

Federal Revision Date: April 4, 2014

Subpart A—General Provisions

Contents

§60.1 Applicability.
§60.2 Definitions.
§60.3 Units and abbreviations.
§60.4 Address.
§60.5 Determination of construction or modification.
§60.6 Review of plans.
§60.7 Notification and record keeping.
§60.8 Performance tests.
§60.9 Availability of information.
§60.10 State authority.
§60.11 Compliance with standards and maintenance requirements.
§60.12 Circumvention.
§60.13 Monitoring requirements.
§60.14 Modification.
§60.15 Reconstruction.
§60.16 Priority list.
§60.17 Incorporations by reference.
§60.18 General control device and work practice requirements.
§60.19 General notification and reporting requirements.
Table 1 to Subpart A of Part 60—Detection Sensitivity Levels (grams per hour)

§60.1 Applicability.

(a) Except as provided in subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (Act) as amended November 15, 1990 (42 U.S.C. 7661). For more information about obtaining an operating permit see part 70 of this chapter.

(d) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) 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”).

(2) Except for compliance with 40 CFR 60.49b(u), the site shall have the option of either complying directly with the requirements of this part, or reducing the site-wide emissions caps 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 site-wide emissions caps 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 part.

(3) Notwithstanding the provisions of paragraph (d)(2) of this section, for any provisions of this part except for Subpart Kb, the owner/operator of the site shall comply with the applicable provisions of this part if the Administrator determines that compliance with the provisions of this part is necessary for achieving the objectives of the regulation and the Administrator notifies the site in accordance with the provisions of the permit issued pursuant to 40 CFR 52.2454.

[40 FR 53346, Nov. 17, 1975, as amended at 55 FR 51382, Dec. 13, 1990; 59 FR 12427, Mar. 16, 1994; 62 FR 52641, Oct. 8, 1997]

§60.2 Definitions.

The terms used in this part are defined in the Act or in this section as follows:

Act means the Clean Air Act (42 U.S.C. 7401 *et seq.*)

Administrator means the Administrator of the Environmental Protection Agency or his authorized representative.

Affected facility means, with reference to a stationary source, any apparatus to which a standard is applicable.

Alternative method means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

Approved permit program means a State permit program approved by the Administrator as meeting the requirements of part 70 of this chapter or a Federal permit program established in this chapter pursuant to Title V of the Act (42 U.S.C. 7661).

Capital expenditure means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable "annual asset guideline repair allowance percentage" specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any "excluded additions" as defined in IRS Publication 534, as would be done for tax purposes.

Clean coal technology demonstration project means a project using funds appropriated under the heading 'Department of Energy-Clean Coal Technology', up to a total amount of \$2,500,000,000 for commercial demonstrations of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency.

Commenced means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

Construction means fabrication, erection, or installation of an affected facility.

Continuous monitoring system means the total equipment, required under the emission monitoring sections in applicable subparts, used to sample and condition (if applicable), to analyze, and to provide a permanent record of emissions or process parameters.

Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

Equivalent method means any method of sampling and analyzing for an air pollutant which has been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference method, under specified conditions.

Excess Emissions and Monitoring Systems Performance Report is a report that must be submitted periodically by a source in order to provide data on its compliance with stated emission limits and operating parameters, and on the performance of its monitoring systems.

Existing facility means, with reference to a stationary source, any apparatus of the type for which a standard is promulgated in this part, and the construction or modification of which was commenced before the date of proposal of that standard; or any apparatus which could be altered in such a way as to be of that type.

Force majeure means, for purposes of §60.8, an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents the owner or operator from complying with the regulatory requirement to conduct performance tests within the specified timeframe despite the affected facility's best efforts to fulfill the obligation. Examples of such events are acts of nature, acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility.

Isokinetic sampling means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

Issuance of a part 70 permit will occur, if the State is the permitting authority, in accordance with the requirements of part 70 of this chapter and the applicable, approved State permit program. When the EPA is the permitting authority, issuance of a Title V permit occurs immediately after the EPA takes final action on the final permit.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

Monitoring device means the total equipment, required under the monitoring of operations sections in applicable subparts, used to measure and record (if applicable) process parameters.

Nitrogen oxides means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

One-hour period means any 60-minute period commencing on the hour.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Owner or operator means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

Part 70 permit means any permit issued, renewed, or revised pursuant to part 70 of this chapter.

Particulate matter means any finely divided solid or liquid material, other than uncombined water, as measured by the reference methods specified under each applicable subpart, or an equivalent or alternative method.

Permit program means a comprehensive State operating permit system established pursuant to title V of the Act (42 U.S.C. 7661) and regulations codified in part 70 of this chapter and applicable State regulations, or a comprehensive Federal operating permit system established pursuant to title V of the Act and regulations codified in this chapter.

Permitting authority means:

(1) The State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to carry out a permit program under part 70 of this chapter; or

(2) The Administrator, in the case of EPA-implemented permit programs under title V of the Act (42 U.S.C. 7661).

Proportional sampling means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

Reactivation of a very clean coal-fired electric utility steam generating unit means any physical change or change in the method of operation associated with the commencement of commercial operations by a coal-fired utility unit after a period of discontinued operation where the unit:

(1) Has not been in operation for the two-year period prior to the enactment of the Clean Air Act Amendments of 1990, and the emissions from such unit continue to be carried in the permitting authority's emissions inventory at the time of enactment;

(2) Was equipped prior to shut-down with a continuous system of emissions control that achieves a removal efficiency for sulfur dioxide of no less than 85 percent and a removal efficiency for particulates of no less than 98 percent;

(3) Is equipped with low-NO_x burners prior to the time of commencement of operations following reactivation; and

(4) Is otherwise in compliance with the requirements of the Clean Air Act.

Reference method means any method of sampling and analyzing for an air pollutant as specified in the applicable subpart.

Repowering means replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of November 15, 1990. Repowering shall also include any oil and/or

gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

Run means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

Shutdown means the cessation of operation of an affected facility for any purpose.

Six-minute period means any one of the 10 equal parts of a one-hour period.

Standard means a standard of performance proposed or promulgated under this part.

Standard conditions means a temperature of 293 K (68F) and a pressure of 101.3 kilopascals (29.92 in Hg).

Startup means the setting in operation of an affected facility for any purpose.

State means all non-Federal authorities, including local agencies, interstate associations, and State-wide programs, that have delegated authority to implement: (1) The provisions of this part; and/or (2) the permit program established under part 70 of this chapter. The term State shall have its conventional meaning where clear from the context.

Stationary source means any building, structure, facility, or installation which emits or may emit any air pollutant.

Title V permit means any permit issued, renewed, or revised pursuant to Federal or State regulations established to implement title V of the Act (42 U.S.C. 7661). A title V permit issued by a State permitting authority is called a part 70 permit in this part.

Volatile Organic Compound means any organic compound which participates in atmospheric photochemical reactions; or which is measured by a reference method, an equivalent method, an alternative method, or which is determined by procedures specified under any subpart.

[44 FR 55173, Sept. 25, 1979, as amended at 45 FR 5617, Jan. 23, 1980; 45 FR 85415, Dec. 24, 1980; 54 FR 6662, Feb. 14, 1989; 55 FR 51382, Dec. 13, 1990; 57 FR 32338, July 21, 1992; 59 FR 12427, Mar. 16, 1994; 72 FR 27442, May 16, 2007]

§60.3 Units and abbreviations.

Used in this part are abbreviations and symbols of units of measure. These are defined as follows:

(a) System International (SI) units of measure:

A—ampere

g—gram

Hz—hertz

J—joule

K—degree Kelvin

kg—kilogram

m—meter

m³—cubic meter

mg—milligram—10⁻³ gram

mm—millimeter—10⁻³ meter

Mg—megagram—10⁶ gram

mol—mole

N—newton

ng—nanogram—10⁻⁹ gram

nm—nanometer—10⁻⁹ meter

Pa—pascal

s—second

V—volt

W—watt

Ω—ohm

μg—microgram—10⁻⁶ gram

(b) Other units of measure:

Btu—British thermal unit

°C—degree Celsius (centigrade)

cal—calorie

cfm—cubic feet per minute

cu ft—cubic feet

dcf—dry cubic feet

dcm—dry cubic meter

dscf—dry cubic feet at standard conditions

dscm—dry cubic meter at standard conditions

eq—equivalent

°F—degree Fahrenheit

ft—feet

gal—gallon

gr—grain

g-eq—gram equivalent

hr—hour

in—inch

k—1,000

l—liter

lpm—liter per minute

lb—pound

meq—milliequivalent

min—minute

ml—milliliter

mol. wt.—molecular weight

ppb—parts per billion

ppm—parts per million

psia—pounds per square inch absolute

psig—pounds per square inch gage

°R—degree Rankine

scf—cubic feet at standard conditions

scfh—cubic feet per hour at standard conditions

scm—cubic meter at standard conditions

sec—second

sq ft—square feet

std—at standard conditions

(c) Chemical nomenclature:

CdS—cadmium sulfide

CO—carbon monoxide

CO₂—carbon dioxide

HCl—hydrochloric acid

Hg—mercury

H₂O—water

H₂S—hydrogen sulfide

H₂SO₄—sulfuric acid

N₂—nitrogen

NO—nitric oxide

NO₂—nitrogen dioxide

NO_x—nitrogen oxides

O₂—oxygen

SO₂—sulfur dioxide

SO₃—sulfur trioxide

SO_x—sulfur oxides

(d) Miscellaneous:

A.S.T.M.—American Society for Testing and Materials

[42 FR 37000, July 19, 1977; 42 FR 38178, July 27, 1977]

§60.4 Address.

All addresses that pertain to Florida have been incorporated.

(a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental Protection Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices.

Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee),
Director, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, 61
Forsyth St. SW., Suite 9T43, Atlanta, Georgia 30303-8960.

(b) Section 111(c) directs the Administrator to delegate to each State, when appropriate, the authority to implement and enforce standards of performance for new stationary sources located in such State. All information required to be submitted to EPA under paragraph (a) of this section, must also be submitted to the appropriate State Agency of any State to which this authority has been delegated (provided, that each specific delegation may except sources from a certain Federal or State reporting requirement). The appropriate mailing address for those States whose delegation request has been approved is as follows:

(K) State of Florida: Florida Department of Environmental Protection, Division of Air Resources

[40 FR 18169, Apr. 25, 1975]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting §60.4 see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and at www.fdsys.gov.

§60.5 Determination of construction or modification.

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

[40 FR 58418, Dec. 16, 1975]

§60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b)(1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974]

§60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

(2) [Reserved]

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in §60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with §60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by §60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by §60.8 in lieu of Method 9 observation data as allowed by §60.11(e)(5) of this part. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) shall both be submitted.

FIGURE 1—SUMMARY REPORT—GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

APPENDIX E - NSPS 40 CFR 60 SUBPART A (GENERAL PROVISIONS)

Pollutant (Circle One—SO₂/NO_x/TRS/H₂S/CO/Opacity)

Reporting period dates: From _____ to _____

Company:

Emission Limitation

Address:

Monitor Manufacturer and Model No.

Date of Latest CMS Certification or Audit

Process Unit(s) Description:

Total source operating time in reporting period¹

Emission data summary¹	CMS performance summary¹	
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:	
a. Startup/shutdown	a. Monitor equipment malfunctions	
b. Control equipment problems	b. Non-Monitor equipment malfunctions	
c. Process problems	c. Quality assurance calibration	
d. Other known causes	d. Other known causes	
e. Unknown causes	e. Unknown causes	
2. Total duration of excess emission	2. Total CMS Downtime	
3. Total duration of excess emissions × (100) [Total source operating time]	3. [Total CMS Downtime] × (100) [Total source operating time]	% ²

¹For opacity, record all times in minutes. For gases, record all times in hours.

²For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in §60.7(c) shall be submitted.

On a separate page, describe any changes since last quarter in CMS, process or controls. I certify that the information contained in this report is true, accurate, and complete.

Name

Signature

Title

Date

(e)(1) Notwithstanding the frequency of reporting requirements specified in paragraph (c) of this section, an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

(iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in paragraphs (e)(1) and (e)(2) of this section.

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

[36 FR 24877, Dec. 28, 1971, as amended at 40 FR 46254, Oct. 6, 1975; 40 FR 58418, Dec. 16, 1975; 45 FR 5617, Jan. 23, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 52 FR 9781, Mar. 26, 1987; 55 FR 51382, Dec. 13, 1990; 59 FR 12428, Mar. 16, 1994; 59 FR 47265, Sep. 15, 1994; 64 FR 7463, Feb. 12, 1999]

§60.8 Performance tests.

(a) Except as specified in paragraphs (a)(1), (a)(2), (a)(3), and (a)(4) of this section, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(1) If a force majeure is about to occur, occurs, or has occurred for which the affected owner or operator intends to assert a claim of force majeure, the owner or operator shall notify the Administrator, in writing as soon as practicable following the date the owner or operator first knew, or through due diligence should have known that the event may cause or caused a delay in testing beyond the regulatory deadline, but the notification must occur before the performance test deadline unless the initial force majeure or a subsequent force majeure event delays the notice, and in such cases, the notification shall occur as soon as practicable.

(2) The owner or operator shall provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in testing beyond the regulatory deadline to the force majeure; describe the measures taken or to be taken to minimize the delay; and identify a date by which the owner or operator proposes to conduct the performance test. The performance test shall be conducted as soon as practicable after the force majeure occurs.

(3) The decision as to whether or not to grant an extension to the performance test deadline is solely within the discretion of the Administrator. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an extension as soon as practicable.

(4) Until an extension of the performance test deadline has been approved by the Administrator under paragraphs (a)(1), (2), and (3) of this section, the owner or operator of the affected facility remains strictly subject to the requirements of this part.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when

necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the Administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

(g) The performance testing shall include a test method performance audit (PA) during the performance test. The PAs consist of blind audit samples supplied by an accredited audit sample provider and analyzed during the performance test in order to provide a measure of test data bias. Gaseous audit samples are designed to audit the performance of the sampling system as well as the analytical system and must be collected by the sampling system during the compliance test just as the compliance samples are collected. If a liquid or solid audit sample is designed to audit the sampling system, it must also be collected by the sampling system during the compliance test. If multiple sampling systems or sampling trains are used during the compliance test for any of the test methods, the tester is only required to use one of the sampling systems per method to collect the audit sample. The audit sample must be analyzed by the same analyst using the same analytical reagents and analytical system and at the same time as the compliance samples. Retests are required when there is a failure to produce acceptable results for an audit sample. However, if the audit results do not affect the compliance or noncompliance status of the affected facility, the compliance authority may waive the reanalysis requirement, further audits, or retests and accept the results of the

compliance test. Acceptance of the test results shall constitute a waiver of the reanalysis requirement, further audits, or retests. The compliance authority may also use the audit sample failure and the compliance test results as evidence to determine the compliance or noncompliance status of the affected facility. A blind audit sample is a sample whose value is known only to the sample provider and is not revealed to the tested facility until after they report the measured value of the audit sample. For pollutants that exist in the gas phase at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in air or nitrogen that can be introduced into the sampling system of the test method at or near the same entry point as a sample from the emission source. If no gas phase audit samples are available, an acceptable alternative is a sample of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. For samples that exist only in a liquid or solid form at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. An accredited audit sample provider (AASP) is an organization that has been accredited to prepare audit samples by an independent, third party accrediting body.

(1) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3A and 3C of appendix A-3 of part 60, Methods 6C, 7E, 9, and 10 of appendix A-4 of part 60, Methods 18 and 19 of appendix A-6 of part 60, Methods 20, 22, and 25A of appendix A-7 of part 60, Methods 30A and 30B of appendix A-8 of part 60, and Methods 303, 318, 320, and 321 of appendix A of part 63 of this chapter. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. "Commercially available" means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, www.epa.gov/ttn/emc, to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request and the compliance authority may grant a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

(2) An AASP shall have and shall prepare, analyze, and report the true value of audit samples in accordance with a written technical criteria document that describes how audit samples will be prepared and distributed in a manner that will ensure the integrity of the audit sample program. An acceptable technical criteria document shall contain standard operating procedures for all of the following operations:

- (i) Preparing the sample;
- (ii) Confirming the true concentration of the sample;

(iii) Defining the acceptance limits for the results from a well qualified tester. This procedure must use well established statistical methods to analyze historical results from well qualified testers. The acceptance limits shall be set so that there is 95 percent confidence that 90 percent of well qualified labs will produce future results that are within the acceptance limit range.

(iv) Providing the opportunity for the compliance authority to comment on the selected concentration level for an audit sample;

(v) Distributing the sample to the user in a manner that guarantees that the true value of the sample is unknown to the user;

(vi) Recording the measured concentration reported by the user and determining if the measured value is within acceptable limits;

(vii) The AASP shall report the results from each audit sample in a timely manner to the compliance authority and then to the source owner, operator, or representative. The AASP shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the source owner, operator, or representative. The results shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, and whether the testing company passed or failed the audit. The AASP shall report the true value of the audit sample to the compliance authority. The AASP may report the true value to the source owner, operator, or representative if the AASP's operating plan ensures that no laboratory will receive the same audit sample twice.

(viii) Evaluating the acceptance limits of samples at least once every two years to determine in cooperation with the voluntary consensus standard body if they should be changed;

(ix) Maintaining a database, accessible to the compliance authorities, of results from the audit that shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, the true value of the audit sample, the acceptance range for the measured value, and whether the testing company passed or failed the audit.

(3) The accrediting body shall have a written technical criteria document that describes how it will ensure that the AASP is operating in accordance with the AASP technical criteria document that describes how audit samples are to be prepared and distributed. This document shall contain standard operating procedures for all of the following operations:

(i) Checking audit samples to confirm their true value as reported by the AASP;

(ii) Performing technical systems audits of the AASP's facilities and operating procedures at least once every two years;

(iii) Providing standards for use by the voluntary consensus standard body to approve the accrediting body that will accredit the audit sample providers.

(4) The technical criteria documents for the accredited sample providers and the accrediting body shall be developed through a public process guided by a voluntary consensus standards body (VCSB). The VCSB shall operate in accordance with the procedures and requirements in the Office of Management and Budget Circular A-119. A copy of Circular A-119 is available upon request by writing the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, by calling (202) 395-6880 or downloading online at http://standards.gov/standards_gov/a119.cfm. The VCSB shall approve all accrediting bodies. The Administrator will review all technical criteria documents. If the technical criteria

documents do not meet the minimum technical requirements in paragraphs (g)(2) through (4) of this section, the technical criteria documents are not acceptable and the proposed audit sample program is not capable of producing audit samples of sufficient quality to be used in a compliance test. All acceptable technical criteria documents shall be posted on the EPA Web site at the following URL, <http://www.epa.gov/ttn/emc>.

(h) Unless otherwise specified in the applicable subpart, each test location must be verified to be free of cyclonic flow and evaluated for the existence of emission gas stratification and the required number of sampling traverse points. If other procedures are not specified in the applicable subpart to the regulations, use the appropriate procedures in Method 1 to check for cyclonic flow and Method 7E to evaluate emission gas stratification and selection of sampling points.

(i) Whenever the use of multiple calibration gases is required by a test method, performance specification, or quality assurance procedure in a part 60 standard or appendix, Method 205 of 40 CFR part 51, appendix M of this chapter, "Verification of Gas Dilution Systems for Field Instrument Calibrations," may be used.

[36 FR 24877, Dec. 23, 1971, as amended at 39 FR 9314, Mar. 8, 1974; 42 FR 57126, Nov. 1, 1977; 44 FR 33612, June 11, 1979; 54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989; 64 FR 7463, Feb. 12, 1999; 72 FR 27442, May 16, 2007; 75 FR 55646, Sept. 13, 2010; 79 FR 11241, Feb. 27, 2014]

§60.9 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§60.5 and 60.6 is governed by §§2.201 through 2.213 of this chapter and not by §2.301 of this chapter.)

§60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

§60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by §60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in paragraph (e)(5) of this section. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e)(1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in §60.8 unless one of the following conditions apply. If no performance test under §60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under §60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in §60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under §60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in paragraph (e)(5) of this section, the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of this part, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in paragraph (e)(3) of this section, the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with paragraph (b) of this section, shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under §60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in §60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of paragraph (e)(1) of this section shall apply.

(4) An owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by §60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and §60.8 performance test results.

(5) An owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under §60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under §60.8 is conducted. Once the owner or operator of an affected facility

has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under §60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under §60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under §60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in §60.13(c) of this part, that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine compliance with the opacity standard.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by §60.8, the opacity observation results and observer certification required by §60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by §60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with §60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the FEDERAL REGISTER.

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[38 FR 28565, Oct. 15, 1973, as amended at 39 FR 39873, Nov. 12, 1974; 43 FR 8800, Mar. 3, 1978; 45 FR 23379, Apr. 4, 1980; 48 FR 48335, Oct. 18, 1983; 50 FR 53113, Dec. 27, 1985; 51 FR 1790, Jan. 15, 1986; 52 FR 9781, Mar. 26, 1987; 62 FR 8328, Feb. 24, 1997; 65 FR 61749, Oct. 17, 2000]

§60.12 Circumvention.

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[39 FR 9314, Mar. 8, 1974]

§60.13 Monitoring requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to this part, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under §60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under §60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of this part before the performance test required under §60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under §60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of this part. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under §60.8 and as described in §60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in paragraph (c) of this section at least 10 days before the performance test required under §60.8 is conducted.

(2) Except as provided in paragraph (c)(1) of this section, the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d)(1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once each operating day in accordance with a written procedure. The zero and span must, at a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part must check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is defined in the applicable version of PS-1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures must be followed for a COMS. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition using a certified neutral density filter or other related technique to produce a known obstruction of the light beam. Such procedures must provide a system check of all active analyzer internal optics with power or curvature, all active electronic circuitry including the light source and photodetector assembly, and electronic or electro-mechanical systems and hardware and or software used during normal measurement operation.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraph (c) of this section for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(2) All continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(h)(1) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in §60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

(i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, *i.e.*, one data point in each of the 15-minute quadrants of the hour.

(ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or

(B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Owners and operators complying with the requirements of §60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (e.g., hours with 30 minutes of unit operation under §60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O₂ or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in Section 8.4 of Performance Specification 2 and substitute the procedures in Section 16.0 if the results of a performance test conducted according to the requirements in §60.8 of this subpart or other tests performed following the criteria in §60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in Section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure, that the CEMS data indicate that the source emissions are approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., §60.45(g) (2) and (3), §60.73(e), and §60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in Section 8.4 of Performance Specification 2.

[40 FR 46255, Oct. 6, 1975; 40 FR 59205, Dec. 22, 1975, as amended at 41 FR 35185, Aug. 20, 1976; 48 FR 13326, Mar. 30, 1983; 48 FR 23610, May 25, 1983; 48 FR 32986, July 20, 1983; 52 FR 9782, Mar. 26, 1987; 52 FR 17555, May 11, 1987; 52 FR 21007, June 4, 1987; 64 FR 7463, Feb. 12, 1999; 65 FR 48920, Aug. 10, 2000; 65 FR 61749, Oct. 17, 2000; 66 FR 44980, Aug. 27, 2001; 71 FR 31102, June 1, 2006; 72 FR 32714, June 13, 2007; 79 FR 11242, Feb. 27, 2014]

EDITORIAL NOTE: At 65 FR 61749, Oct. 17, 2000, §60.13 was amended by revising the words “ng/J of pollutant” to read “ng of pollutant per J of heat input” in the sixth sentence of paragraph (h). However, the amendment could not be incorporated because the words “ng/J of pollutant” do not appear in the sixth sentence of paragraph (h).

§60.14 Modification.

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon

modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(d) [Reserved]

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and §60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by §60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(j)(1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:

(i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A *temporary clean coal control technology demonstration project*, for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

[40 FR 58419, Dec. 16, 1975, as amended at 43 FR 34347, Aug. 3, 1978; 45 FR 5617, Jan. 23, 1980; 57 FR 32339, July 21, 1992; 65 FR 61750, Oct. 17, 2000]

§60.15 Reconstruction.

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) “Reconstruction” means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

[40 FR 58420, Dec. 16, 1975]

§60.16 Priority list.

PRIORITIZED MAJOR SOURCE CATEGORIES

<i>Priority Number</i> ¹	<i>Source Category</i>
1.	Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Volatile Organic Liquid Storage Vessels and Handling Equipment
	(a) SOCMI unit processes
	(b) Volatile organic liquid (VOL) storage vessels and handling equipment
	(c) SOCMI fugitive sources
	(d) SOCMI secondary sources
2.	Industrial Surface Coating: Cans
3.	Petroleum Refineries: Fugitive Sources
4.	Industrial Surface Coating: Paper
5.	Dry Cleaning
	(a) Perchloroethylene
	(b) Petroleum solvent
6.	Graphic Arts
7.	Polymers and Resins: Acrylic Resins
8.	Mineral Wool (Deleted)
9.	Stationary Internal Combustion Engines
10.	Industrial Surface Coating: Fabric
11.	Industrial-Commercial-Institutional Steam Generating Units.
12.	Incineration: Non-Municipal (Deleted)
13.	Non-Metallic Mineral Processing
14.	Metallic Mineral Processing
15.	Secondary Copper (Deleted)
16.	Phosphate Rock Preparation
17.	Foundries: Steel and Gray Iron
18.	Polymers and Resins: Polyethylene
19.	Charcoal Production
20.	Synthetic Rubber
	(a) Tire manufacture
	(b) SBR production
21.	Vegetable Oil
22.	Industrial Surface Coating: Metal Coil

APPENDIX E - NSPS 40 CFR 60 SUBPART A (GENERAL PROVISIONS)

23.	Petroleum Transportation and Marketing
24.	By-Product Coke Ovens
25.	Synthetic Fibers
26.	Plywood Manufacture
27.	Industrial Surface Coating: Automobiles
28.	Industrial Surface Coating: Large Appliances
29.	Crude Oil and Natural Gas Production
30.	Secondary Aluminum
31.	Potash (Deleted)
32.	Lightweight Aggregate Industry: Clay, Shale, and Slate ²
33.	Glass
34.	Gypsum
35.	Sodium Carbonate
36.	Secondary Zinc (Deleted)
37.	Polymers and Resins: Phenolic
38.	Polymers and Resins: Urea-Melamine
39.	Ammonia (Deleted)
40.	Polymers and Resins: Polystyrene
41.	Polymers and Resins: ABS-SAN Resins
42.	Fiberglass
43.	Polymers and Resins: Polypropylene
44.	Textile Processing
45.	Asphalt Processing and Asphalt Roofing Manufacture
46.	Brick and Related Clay Products
47.	Ceramic Clay Manufacturing (Deleted)
48.	Ammonium Nitrate Fertilizer
49.	Castable Refractories (Deleted)
50.	Borax and Boric Acid (Deleted)
51.	Polymers and Resins: Polyester Resins
52.	Ammonium Sulfate
53.	Starch
54.	Perlite
55.	Phosphoric Acid: Thermal Process (Deleted)
56.	Uranium Refining

APPENDIX E - NSPS 40 CFR 60 SUBPART A (GENERAL PROVISIONS)

57.	Animal Feed Defluorination (Deleted)
58.	Urea (for fertilizer and polymers)
59.	Detergent (Deleted)
<i>Other Source Categories</i>	
Lead acid battery manufacture ³	
Organic solvent cleaning ³	
Industrial surface coating: metal furniture ³	
Stationary gas turbines ⁴	
Municipal solid waste landfills ⁴	

¹Low numbers have highest priority, e.g., No. 1 is high priority, No. 59 is low priority.

²Formerly titled “Sintering: Clay and Fly Ash”.

³Minor source category, but included on list since an NSPS is being developed for that source category.

⁴Not prioritized, since an NSPS for this major source category has already been promulgated.

[47 FR 951, Jan. 8, 1982, as amended at 47 FR 31876, July 23, 1982; 51 FR 42796, Nov. 25, 1986; 52 FR 11428, Apr. 8, 1987; 61 FR 9919, Mar. 12, 1996]

§60.17 Incorporations by reference.

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the EPA must publish notice of change in the FEDERAL REGISTER and the material must be available to the public. All approved material is available for inspection at the Air and Radiation Docket and Information Center, U.S. EPA, 401 M St. SW., Washington, DC, telephone number 202-566, and is available from the sources listed below. It is also available for inspection at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741-6030 or go to http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.

(b) American Gas Association, available through ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990), IBR approved for §60.107a(d).

(2) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 2: Specification and Installation Requirements (2000), IBR approved for §60.107a(d).

(3) American Gas Association Report No. 11: Measurement of Natural Gas by Coriolis Meter (2003), IBR approved for §60.107a(d).

(4) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Revised February 2006), IBR approved for §60.107a(d).

(c) American Hospital Association (AHA) Service, Inc., Post Office Box 92683, Chicago, Illinois 60675-2683. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-124), Room M-1500, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

(1) An Ounce of Prevention: Waste Reduction Strategies for Health Care Facilities. American Society for Health Care Environmental Services of the American Hospital Association. Chicago, Illinois. 1993. AHA Catalog No. 057007. ISBN 0-87258-673-5. IBR approved for §§60.35e and 60.55c.

(2) [Reserved]

(d) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005.

(1) API Publication 2517, Evaporation Loss from External Floating Roof Tanks, Second Edition, February 1980, IBR approved for §§60.111(i), 60.111a(f), and 60.116b(e).

(2) API Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices, First Edition, August 2005, IBR approved for §60.107a(d).

(e) American Public Health Association, 1015 18th Street NW., Washington, DC 20036.

(1) “Standard Methods for the Examination of Water and Wastewater,” 16th edition, 1985. Method 303F: “Determination of Mercury by the Cold Vapor Technique.” Incorporated by reference for appendix A-8 to part 60, Method 29, §§9.2.3, 10.3, and 11.1.3.

(2) 2540 G. Total, Fixed, and Volatile Solids in Solid and Semisolid Samples, in Standard Methods for the Examination of Water and Wastewater, 20th Edition, 1998, IBR approved for §60.154(b).

(f) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016-5990, Telephone (800) 843-2763, and is also available at the following Web site: <http://www.asme.org>.

(1) ASME Interim Supplement 19.5 on Instruments and Apparatus: Application, Part II of Fluid Meters, 6th Edition (1971), IBR approved for §§60.58a(h), 60.58b(i), 60.1320(a), and 60.1810(a).

(2) ASME MFC-3M-2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, IBR approved for §60.107a(d).

(3) ASME/ANSI MFC-4M-1986 (Reaffirmed 2008), Measurement of Gas Flow by Turbine Meters, IBR approved for §60.107a(d).

(4) ASME/ANSI MFC-5M-1985 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, IBR approved for §60.107a(d).

(5) ASME MFC-6M-1998 (Reaffirmed 2005), Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for §60.107a(d).

(6) ASME/ANSI MFC-7M-1987 (Reaffirmed 2006), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, IBR approved for §60.107a(d).

(7) ASME/ANSI MFC-9M-1988 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits by Weighing Method, IBR approved for §60.107a(d).

(8) ASME MFC-11M-2006, Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for §60.107a(d).

(9) ASME MFC-14M-2003, Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for §60.107a(d).

(10) ASME MFC-16-2007, Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters, IBR approved for §60.107a(d).

(11) ASME MFC-18M-2001, Measurement of Fluid Flow Using Variable Area Meters, IBR approved for §60.107a(d).

(12) ASME MFC-22-2007, Measurement of Liquid by Turbine Flowmeters, IBR approved for §60.107a(d).

(13) ASME PTC 4.1-1964 (Reaffirmed 1991), Power Test Codes: Test Code for Steam Generating Units (with 1968 and 1969 Addenda), IBR approved for §§60.46b, 60.58a(h), 60.58b(i), 60.1320(a), and 60.1810(a).

(14) ASME/ANSI PTC 19.10-1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], (Issued August 31, 1981), IBR approved for §§60.56c(b), 60.63(f), 60.106(e), 60.104a(d), (h), (i), and (j), 60.105a(d), (f), and (g), §60.106a(a), §60.107a(a), (c), and (d), tables 1 and 3 to subpart EEEE, tables 2 and 4 to subpart FFFF, table 2 to subpart JJJJ, §60.285a(f), §§60.4415(a), 60.2145(s) and (t), 60.2710(s) (t), and (w), 60.2730(q), 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§60.5406(c) and 60.5413(b).

(15) ASME QRO-1-1994, Standard for the Qualification and Certification of Resource Recovery Facility Operators, IBR approved for §§60.54b(a) and (b), 60.56a, 60.1185(a) and (c), and 60.1675(a) and (c).

(g) American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428-2959; also available through ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106.

(1) ASTM A99-76, Standard Specification for Ferromanganese, IBR approved for §60.261.

(2) ASTM A99-82 (Reapproved 1987), Standard Specification for Ferromanganese, IBR approved for §60.261.

(3) ASTM A100-69, Standard Specification for Ferrosilicon, IBR approved for §60.261.

(4) ASTM A100-74, Standard Specification for Ferrosilicon, IBR approved for §60.261.

(5) ASTM A100-93, Standard Specification for Ferrosilicon, IBR approved for §60.261.

(6) ASTM A101-73, Standard Specification for Ferrochromium, IBR approved for §60.261.

(7) ASTM A101-93, Standard Specification for Ferrochromium, IBR approved for §60.261.

(8) ASTM A482-76, Standard Specification for Ferrochromesilicon, IBR approved for §60.261.

(9) ASTM A482-93, Standard Specification for Ferrochromesilicon, IBR approved for §60.261.

- (10) ASTM A483-64, Standard Specification for Silicomanganese, IBR approved for §60.261.
- (11) ASTM A483-74 (Reapproved 1988), Standard Specification for Silicomanganese, IBR approved for §60.261.
- (12) ASTM A495-76, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for §60.261.
- (13) ASTM A495-94, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for §60.261.
- (14) ASTM D86-78, Distillation of Petroleum Products, IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).
- (15) ASTM D86-82, Distillation of Petroleum Products, IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).
- (16) ASTM D86-90, Distillation of Petroleum Products, IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).
- (17) ASTM D86-93, Distillation of Petroleum Products, IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).
- (18) ASTM D86-95, Distillation of Petroleum Products, IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h).
- (19) ASTM D86-96, Distillation of Petroleum Products, (Approved April 10, 1996), IBR approved for §§60.562-2(d), 60.593(d), 60.593a(d), 60.633(h), and 60.5401(f).
- (20) ASTM D129-64, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (21) ASTM D129-78, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (22) ASTM D129-95, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§60.106(j) and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (23) ASTM D129-00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §60.335(b).
- (24) ASTM D129-00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §60.4415(a).
- (25) ASTM D240-76, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.
- (26) ASTM D240-92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§60.46(c), 60.296(b), and appendix A-7: Method 19, Section 12.5.2.2.3.
- (27) ASTM D240-02 (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, (Approved May 1, 2007), IBR approved for §60.107a(d).

(28) ASTM D270-65, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.

(29) ASTM D270-75, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.

(30) ASTM D323-82, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§60.111(l), 60.111a(g), 60.111b, and 60.116b(f).

(31) ASTM D323-94, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§60.111(l), 60.111a(g), 60.111b, and 60.116b(f).

(32) ASTM D388-77, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(33) ASTM D388-90, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(34) ASTM D388-91, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(35) ASTM D388-95, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(36) ASTM D388-98a, Standard Specification for Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(37) ASTM D388-99 (Reapproved 2004)^{e, 1} Standard Specification for Classification of Coals by Rank, IBR approved for §§60.41, 60.45(f), 60.41Da, 60.41b, 60.41c, and 60.251.

(38) ASTM D396-78, Standard Specification for Fuel Oils, IBR approved for §§60.41b, 60.41c, 60.111(b), and 60.111a(b).

(39) ASTM D396-89, Standard Specification for Fuel Oils, IBR approved for §§60.41b, 60.41c, 60.111(b), and 60.111a(b).

(40) ASTM D396-90, Standard Specification for Fuel Oils, IBR approved for §§60.41b, 60.41c, 60.111(b), and 60.111a(b).

(41) ASTM D396-92, Standard Specification for Fuel Oils, IBR approved for §§60.41b, 60.41c, 60.111(b), and 60.111a(b).

(42) ASTM D396-98, Standard Specification for Fuel Oils, IBR approved for §§60.41b, 60.41c, 60.111(b), and 60.111a(b).

(43) ASTM D975-78, Standard Specification for Diesel Fuel Oils, IBR approved for §§60.111(b) and 60.111a(b).

(44) ASTM D975-96, Standard Specification for Diesel Fuel Oils, IBR approved for §§60.111(b) and 60.111a(b).

- (45) ASTM D975-98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§60.111(b) and 60.111a(b).
- (46) ASTM D975-08a, Standard Specification for Diesel Fuel Oils, IBR approved for §§60.41b and 60.41c.
- (47) ASTM D1072-80, Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.335(b).
- (48) ASTM D1072-90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.335(b).
- (49) ASTM D1072-90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for §60.4415(a).
- (50) ASTM D1137-53, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for §60.45(f).
- (51) ASTM D1137-75, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for §60.45(f).
- (52) ASTM D1193-77, Standard Specification for Reagent Water, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A-4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A-5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A-8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.
- (53) ASTM D1193-91, Standard Specification for Reagent Water, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; appendix A-4 to part 60: Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; appendix A-5 to part 60: Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; appendix A-8 to part 60: Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.
- (54) ASTM D1266-87, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§60.106(j) and 60.335(b).
- (55) ASTM D1266-91, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§60.106(j) and 60.335(b).
- (56) ASTM D1266-98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§60.106(j) and 60.335(b).
- (57) ASTM D1266-98 (Reapproved 2003)^{e, 1}, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §60.4415(a).
- (58) ASTM D1475-60 (Reapproved 1980), Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for §60.435(d), appendix A-8 to part 60: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.
- (59) ASTM D1475-90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for §60.435(d), appendix A-8 to part 60: Method 24, Section 6.1; and Method 24A, §§6.5 and 7.1.
- (60) ASTM D1552-83, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(61) ASTM D1552-95, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(62) ASTM D1552-01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§60.106(j), 60.335(b), and appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(63) ASTM D1552-03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §60.4415(a).

(64) ASTM D1826-77, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§60.45(f), 60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.3.2.4.

(65) ASTM D1826-94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§60.45(f), 60.46(c), 60.296(b), and appendix A-7 to part 60: Method 19, Section 12.3.2.4.

(66) ASTM D1826-94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, (Approved May 10, 2003), IBR approved for §60.107a(d).

(67) ASTM D1835-87, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§60.41Da, 60.41b, and 60.41c.

(68) ASTM D1835-91, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§60.41Da, 60.41b, and 60.41c.

(69) ASTM D1835-97, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§60.41Da, 60.41b, and 60.41c.

(70) ASTM D1835-03a, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§60.41Da, 60.41b, and 60.41c.

(71) ASTM D1945-64, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §60.45(f).

(72) ASTM D1945-76, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §60.45(f).

(73) ASTM D1945-91, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §60.45(f).

(74) ASTM D1945-96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for §60.45(f).

(75) ASTM D1945-03 (Reapproved 2010), Standard Method for Analysis of Natural Gas by Gas Chromatography, (Approved January 1, 2010), IBR approved for §§60.107a(d) and 60.5413(d).

(76) ASTM D1946-77, Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§60.18(f), 60.45(f), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(77) ASTM D1946-90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§60.18(f), 60.45(f), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(78) ASTM D1946-90 (Reapproved 2006), Standard Method for Analysis of Reformed Gas by Gas Chromatography, (Approved June 1, 2006), IBR approved for §60.107a(d).

(79) ASTM D2013-72, Standard Method of Preparing Coal Samples for Analysis, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(80) ASTM D2013-86, Standard Method of Preparing Coal Samples for Analysis, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(81) ASTM D2015-77 (Reapproved 1978), Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §§60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(82) ASTM D2015-96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for §§60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(83) ASTM D2016-74, Standard Test Methods for Moisture Content of Wood, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(84) ASTM D2016-83, Standard Test Methods for Moisture Content of Wood, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(85) ASTM D2234-76, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(86) ASTM D2234-96, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(87) ASTM D2234-97b, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(88) ASTM D2234-98, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.1.

(89) ASTM D2369-81, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.

(90) ASTM D2369-87, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.

(91) ASTM D2369-90, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.

(92) ASTM D2369-92, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.

(93) ASTM D2369-93, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.

(94) ASTM D2369-95, Standard Test Method for Volatile Content of Coatings, IBR approved for appendix A-8 to part 60: Method 24, Section 6.2.

(95) ASTM D2382-76, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(96) ASTM D2382-88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(e), 60.664(e), and 60.704(d).

(97) ASTM D2504-67, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§60.485(g) and 60.485a(g).

(98) ASTM D2504-77, Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§60.485(g) and 60.485a(g).

(99) ASTM D2504-88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§60.485(g) and 60.485a(g).

(100) ASTM D2584-68(Reapproved 1985), Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for §60.685(c).

(101) ASTM D2584-94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for §60.685(c).

(102) ASTM D2597-94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for §60.335(b).

(103) ASTM D2622-87, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§60.106(j) and 60.335(b).

(104) ASTM D2622-94, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§60.106(j) and 60.335(b).

(105) ASTM D2622-98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§60.106(j) and 60.335(b).

(106) ASTM D2622-05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.4415(a).

(107) ASTM D2879-83 Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).

(108) ASTM D2879-96, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).

(109) ASTM D2879-97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§60.111b(f)(3), 60.116b(e), 60.116b(f), 60.485(e), and 60.485a(e).

(110) ASTM D2880-78, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§60.111(b), 60.111a(b), and 60.335(d).

(111) ASTM D2880-96, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§60.111(b), 60.111a(b), and 60.335(d).

(112) ASTM D2908-74, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for §60.564(j).

(113) ASTM D2908-91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for §60.564(j).

(114) ASTM D2986-71, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Diethyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(115) ASTM D2986-78, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Diethyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(116) ASTM D2986-95a, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Diethyl Phthalate) Smoke Test, IBR approved for appendix A-3 to part 60: Method 5, Section 7.1.1; appendix A-5 to part 60: Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(117) ASTM D3173-73, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(118) ASTM D3173-87, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(119) ASTM D3176-74, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for §60.45(f)(5)(i) and appendix A-7 to part 60: Method 19, Section 12.3.2.3.

(120) ASTM D3176-89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for §60.45(f)(5)(i) and appendix A-7 to part 60: Method 19, Section 12.3.2.3.

(121) ASTM D3177-75, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(122) ASTM D3177-89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(123) ASTM D3178-73 (Reapproved 1979), Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for §60.45(f).

(124) ASTM D3178-89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for §60.45(f).

(125) ASTM D3246-81, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.335(b).

(126) ASTM D3246-92, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.335(b).

(127) ASTM D3246-96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.335(b).

(128) ASTM D3246-05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for §60.4415(a)(1).

(129) ASTM D3270-73T, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(130) ASTM D3270-80, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(131) ASTM D3270-91, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(132) ASTM D3270-95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for appendix A-5 to part 60: Method 13A, Section 16.1.

(133) ASTM D3286-85, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(134) ASTM D3286-96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(135) ASTM D3370-76, Standard Practices for Sampling Water, IBR approved for §60.564(j).

(136) ASTM D3370-95a, Standard Practices for Sampling Water, IBR approved for §60.564(j).

(137) ASTM D3588-98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, (Approved May 10, 2003), IBR approved for §§60.107a(d) and 60.5413(d).

(138) ASTM D3699-08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008), IBR approved for §§60.41b and 60.41c.

(139) ASTM D3792-79, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.3.

(140) ASTM D3792-91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.3.

(141) ASTM D4017-81, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.

(142) ASTM D4017-90, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.

(143) ASTM D4017-96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for appendix A-7 to part 60: Method 24, Section 6.4.

(144) ASTM D4057-81, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(145) ASTM D4057-95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.3.

(146) ASTM D4057-95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for §60.4415(a).

(147) ASTM D4084-82, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §60.334(h).

(148) ASTM D4084-94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §60.334(h).

(149) ASTM D4084-05, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §§60.4360 and 60.4415(a).

(150) ASTM D4177-95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.2.1.

(151) ASTM D4177-95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for §60.4415(a).

(152) ASTM D4239-85, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(153) ASTM D4239-94, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(154) ASTM D4239-97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(155) ASTM D4294-02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.335(b).

(156) ASTM D4294-03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §60.4415(a).

(157) ASTM D4442-84, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(158) ASTM D4442-92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(159) ASTM D4444-92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters, IBR approved for appendix A-8 to part 60: Method 28, Section 16.1.1.

(160) ASTM D4457-85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1,1,1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for appendix A-7 to part 60: Method 24, Section 6.5.

(161) ASTM D4468-85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§60.335(b) and 60.4415(a).

(162) ASTM D4468-85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, (Approved June 1, 2006), IBR approved for §60.107a(e).

(163) ASTM D4629-02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for §§60.49b(e) and 60.335(b).

(164) ASTM D4809-95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§60.18(f), 60.485(g), 60.485a(g), 60.564(f), 60.614(d), 60.664(e), and 60.704(d).

(165) ASTM D4809-06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), (Approved December 1, 2006), IBR approved for §60.107a(d).

(166) ASTM D4810-88 (Reapproved 1999), Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for §§60.4360 and 60.4415(a).

(167) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, (Approved June 1, 2006), IBR approved for §§60.107a(d) and 60.5413(d).

(168) ASTM D5287-97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for §60.4415(a).

(169) ASTM D5403-93, Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved for appendix A-7 to part 60: Method 24, Section 6.6.

(170) ASTM D5453-00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for §60.335(b).

(171) ASTM D5453-05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for §60.4415(a).

(172) ASTM D5504-01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§60.334(h) and 60.4360.

(173) ASTM D5504-08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, (Approved June 15, 2008), IBR approved for §§60.107a(e) and 60.5413(d).

(174) ASTM D5762-02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for §60.335(b).

(175) ASTM D5865-98, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for §§60.45(f) and 60.46(c), and appendix A-7 to part 60: Method 19, Section 12.5.2.1.3.

(176) ASTM D5865-10, Standard Test Method for Gross Calorific Value of Coal and Coke, (Approved January 1, 2010), IBR approved for §§60.45(f), 60.46(c), and appendix A-7 to part 60: Method 19, section 12.5.2.1.3.

(177) ASTM D6216-98, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, IBR approved for appendix B to part 60: Performance Specification 1.

(178) ASTM D6228-98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §60.334(h).

(179) ASTM D6228-98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §§60.4360 and 60.4415.

(180) ASTM D6348-03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, (Approved October 1, 2003), IBR approved for §60.73a(b), table 7 to subpart IIII, and table 2 to subpart JJJJ.

(181) ASTM D6366-99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for §60.335(b)(9).

(182) ASTM D6420-99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, (Approved October 1, 2004), IBR approved for §60.107a(d) and table 2 to subpart JJJJ.

(183) ASTM D6522-00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for §60.335(a).

(184) ASTM D6522-00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, (Approved October 1, 2005), IBR approved for table 2 to subpart JJJJ, and §§60.5413(b) and (d).

(185) ASTM D6667-01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for §60.335(b).

(186) ASTM D6667-04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for §60.4415(a).

(187) ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§60.41b and 60.41c.

(188) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for §60.56c(b) and appendix B to part 60: Performance Specification 12A, Section 8.6.2.

(189) ASTM D6784-02 (Reapproved 2008) Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), (Approved April 1, 2008), IBR approved for §§60.2165(j) and 60.2730(j), tables 1, 5, 6 and 8 to subpart CCCC, and tables 2, 6, 7, and 9 to subpart DDDD, §§60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, and tables 2 and 3 to subpart MMMM.

(190) ASTM D7467-10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§60.41b and 60.41c.

(191) ASTM E168-67, General Techniques of Infrared Quantitative Analysis, IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(192) ASTM E168-77, General Techniques of Infrared Quantitative Analysis, IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(193) ASTM E168-92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), 60.632(f), and 60.5400.

(194) ASTM E169-63, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(195) ASTM E169-77, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§60.485a(d), 60.593(b), and 60.593a(b), 60.632(f).

(196) ASTM E169-93, General Techniques of Ultraviolet Quantitative Analysis, (Approved May 15, 1993), IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), 60.632(f), and 60.5400(f).

(197) ASTM E260-73, General Gas Chromatography Procedures, IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(198) ASTM E260-91, General Gas Chromatography Procedures, (IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), and 60.632(f).

(199) ASTM E260-96, General Gas Chromatography Procedures, (Approved April 10, 1996), IBR approved for §§60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f), and 60.5406(b).

(200) ASTM E1584-11, Standard Test Method for Assay of Nitric Acid, (Approved August 1, 2011), IBR approved for §60.73a(c).

(201) ASTM UOP539-97, Refinery Gas Analysis by Gas Chromatography, (Copyright 1997), IBR approved for §60.107a(d).

(h) Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209.

(1) AOAC Method 9, Official Methods of Analysis of the Association of Official Analytical Chemists (AOAC), 11th edition, 1970, pp. 11-12, IBR approved for §§60.204(b), 60.214(b), 60.224(b), and 60.234(b).

(2) [Reserved]

(i) U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW., Washington, DC 20460, (202) 272-0167, <http://www.epa.gov>.

(1) EPA-454/R-98-015, Office of Air Quality Planning and Standards (OAQPS) Fabric Filter Bag Leak Detection Guidance, September 1997, IBR approved for §§60.2145(r), 60.2710(r), 60.4905(b), and 60.5225(b).

(2) [Reserved]

(j) The Gas Processors Association, 6526 East 60th Street, Tulsa, OK 74145; also available through Information Handling Services, 15 Inverness Way East, PO Box 1154, Englewood, CO 80150-1154. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20460.

(1) Gas Processors Association Standard 2172-09, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (2009), IBR approved for §60.107a(d).

(2) Gas Processors Association Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (2000), IBR approved for §60.107a(d).

(3) Gas Processors Association Standard 2377-86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, 1986 Revision, IBR approved for §§60.105(b), 60.107a(b), 60.334(h), 60.4360, and 60.4415(a).

(k) International Organization for Standardization (ISO) available through IHS Inc., 15 Inverness Way East, Englewood, CO 80112.

(1) ISO 8178-4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—part 4: Test Cycles for Different Engine Applications, IBR approved for §60.4241(b).

(2) [Reserved]

(l) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, <http://www.iso.org/iso/home.htm>.

(1) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987-10-01)—First Edition, IBR approved for §60.107a(d).

(2) [Reserved]

(m) This material is available for purchase from the National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, Virginia 22161. You may inspect a copy at the EPA's Air and Radiation Docket and Information Center (Docket A-91-61, Item IV-J-125), Room M-1500, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

(1) OMB Bulletin No. 93-17: Revised Statistical Definitions for Metropolitan Areas. Office of Management and Budget, June 30, 1993. NTIS No. PB 93-192-664. IBR approved for §60.31e.

(2) [Reserved]

(n) North American Electric Reliability Corporation, 1325 G Street NW., Suite 600, Washington, DC 20005-3801, <http://www.nerc.com>.

(1) North American Electric Reliability Corporation Reliability Standard EOP-002-3, Capacity and Energy Emergencies, updated November 19, 2012, IBR approved for §§60.4211(f) and 60.4243(d). Also available online: http://www.nerc.com/files/EOP-002-3_1.pdf.

(2) [Reserved]

(o) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Suite 115, Peachtree Corners, GA 30092, Telephone (800) 332-8686, and is also available at the following Web site: <http://www.tappi.org>.

(1) TAPPI Method T 624 cm-11, (Copyright 2011), IBR approved, for §§60.285(d) and 60.285a(d).

(2) [Reserved]

(p) Underwriter's Laboratories, Inc. (UL), 333 Pfingsten Road, Northbrook, IL 60062.

(1) UL 103, Sixth Edition revised as of September 3, 1986, Standard for Chimneys, Factory-built, Residential Type and Building Heating Appliance, IBR approved for Appendix A-8 to part 60.

(2) [Reserved]

(q) Water Pollution Control Federation (WPCF), 2626 Pennsylvania Avenue NW., Washington, DC 20037.

(1) Method 209A, Total Residue Dried at 103-105 °C, in Standard Methods for the Examination of Water and Wastewater, 15th Edition, 1980, IBR approved for §60.683(b).

(2) [Reserved]

(r) West Coast Lumber Inspection Bureau, 6980 SW. Barnes Road, Portland, OR 97223.

(1) West Coast Lumber Standard Grading Rules No. 16, pages 5-21, 90 and 91, September 3, 1970, revised 1984, IBR approved for Appendix A-8 to part 60.

(2) [Reserved]

[79 FR 11242, Feb. 27, 2014, as amended at 79 FR 18965, Apr. 4, 2014]

§60.18 General control device and work practice requirements.

(a) *Introduction.* (1) This section contains requirements for control devices used to comply with applicable subparts of 40 CFR parts 60 and 61. The requirements are placed here for administrative convenience and apply only to facilities covered by subparts referring to this section.

(2) This section also contains requirements for an alternative work practice used to identify leaking equipment. This alternative work practice is placed here for administrative convenience and is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, Appendix A-7, Method 21 monitor.

(b) *Flares.* Paragraphs (c) through (f) apply to flares.

(c)(1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i)(A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, V_{max} , as determined by the following equation:

$$V_{max} = (X_{H2} - K_1) * K_2$$

Where:

V_{max} = Maximum permitted velocity, m/sec.

K_1 = Constant, 6.0 volume-percent hydrogen.

K_2 = Constant, 3.9(m/sec)/volume-percent hydrogen.

X_{H2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in §60.17).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4)(i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, V_{max} , as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max} , as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f)(1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

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where:

H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

$$K = \text{Constant}, 1.740 \times 10^{-7} \left(\frac{1}{\text{ppm}} \right) \left(\frac{\text{g mole}}{\text{scm}} \right) \left(\frac{\text{MJ}}{\text{kcal}} \right)$$

where the standard temperature for $\left(\frac{\text{g mole}}{\text{scm}} \right)$ is 20°C;

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C_i = Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in §60.17); and

H_i = Net heat of combustion of sample component i , kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in §60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity, V_{\max} , for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$$\text{Log}_{10}(V_{\max}) = (H_T + 28.8) / 31.7$$

V_{\max} = Maximum permitted velocity, M/sec

28.8 = Constant

31.7 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity, V_{\max} , for air-assisted flares shall be determined by the following equation.

$$V_{\max} = 8.706 + 0.7084 (H_T)$$

V_{\max} = Maximum permitted velocity, m/sec

8.706=Constant

0.7084=Constant

H_T = The net heating value as determined in paragraph (f)(3).

(g) *Alternative work practice for monitoring equipment for leaks.* Paragraphs (g), (h), and (i) of this section apply to all equipment for which the applicable subpart requires monitoring with a 40 CFR part 60, Appendix A-7, Method 21 monitor, except for closed vent systems, equipment designated as leakless, and equipment identified in the applicable subpart as having no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background. An owner or operator may use an optical gas imaging instrument instead of a 40 CFR part 60, Appendix A-7, Method 21 monitor. Requirements in the existing subparts that are specific to the Method 21 instrument do not apply under this section. All other requirements in the applicable subpart that are not addressed in paragraphs (g), (h), and (i) of this section apply to this standard. For example, equipment specification requirements, and non-Method 21 instrument recordkeeping and reporting requirements in the applicable subpart continue to apply. The terms defined in paragraphs (g)(1) through (5) of this section have meanings that are specific to the alternative work practice standard in paragraphs (g), (h), and (i) of this section.

(1) *Applicable subpart* means the subpart in 40 CFR parts 60, 61, 63, or 65 that requires monitoring of equipment with a 40 CFR part 60, Appendix A-7, Method 21 monitor.

(2) *Equipment* means pumps, valves, pressure relief valves, compressors, open-ended lines, flanges, connectors, and other equipment covered by the applicable subpart that require monitoring with a 40 CFR part 60, Appendix A-7, Method 21 monitor.

(3) *Imaging* means making visible emissions that may otherwise be invisible to the naked eye.

(4) *Optical gas imaging instrument* means an instrument that makes visible emissions that may otherwise be invisible to the naked eye.

(5) *Repair* means that equipment is adjusted, or otherwise altered, in order to eliminate a leak.

(6) *Leak* means:

(i) Any emissions imaged by the optical gas instrument;

(ii) Indications of liquids dripping;

(iii) Indications by a sensor that a seal or barrier fluid system has failed; or

(iv) Screening results using a 40 CFR part 60, Appendix A-7, Method 21 monitor that exceed the leak definition in the applicable subpart to which the equipment is subject.

(h) The alternative work practice standard for monitoring equipment for leaks is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, Appendix A-7, Method 21 monitor.

(1) An owner or operator of an affected source subject to CFR parts 60, 61, 63, or 65 can choose to comply with the alternative work practice requirements in paragraph (i) of this section instead of using the 40 CFR part 60,

Appendix A-7, Method 21 monitor to identify leaking equipment. The owner or operator must document the equipment, process units, and facilities for which the alternative work practice will be used to identify leaks.

(2) Any leak detected when following the leak survey procedure in paragraph (i)(3) of this section must be identified for repair as required in the applicable subpart.

(3) If the alternative work practice is used to identify leaks, re-screening after an attempted repair of leaking equipment must be conducted using either the alternative work practice or the 40 CFR part 60, Appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart to which the equipment is subject.

(4) The schedule for repair is as required in the applicable subpart.

(5) When this alternative work practice is used for detecting leaking equipment, choose one of the monitoring frequencies listed in Table 1 to subpart A of this part in lieu of the monitoring frequency specified for regulated equipment in the applicable subpart. Reduced monitoring frequencies for good performance are not applicable when using the alternative work practice.

(6) When this alternative work practice is used for detecting leaking equipment the following are not applicable for the equipment being monitored:

(i) Skip period leak detection and repair;

(ii) Quality improvement plans; or

(iii) Complying with standards for allowable percentage of valves and pumps to leak.

(7) When the alternative work practice is used to detect leaking equipment, the regulated equipment in paragraph (h)(1)(i) of this section must also be monitored annually using a 40 CFR part 60, Appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart. The owner or operator may choose the specific monitoring period (for example, first quarter) to conduct the annual monitoring. Subsequent monitoring must be conducted every 12 months from the initial period. Owners or operators must keep records of the annual Method 21 screening results, as specified in paragraph (i)(4)(vii) of this section.

(i) An owner or operator of an affected source who chooses to use the alternative work practice must comply with the requirements of paragraphs (i)(1) through (i)(5) of this section.

(1) Instrument Specifications. The optical gas imaging instrument must comply with the requirements in (i)(1)(i) and (i)(1)(ii) of this section.

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in paragraph (i)(2) of this section. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Daily Instrument Check. On a daily basis, and prior to beginning any leak monitoring work, test the optical gas imaging instrument at the mass flow rate determined in paragraph (i)(2)(i) of this section in accordance with the procedure specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each camera configuration used during monitoring (for example, different lenses used), unless an alternative method to demonstrate daily instrument checks has been approved in accordance with paragraph (i)(2)(v) of this section.

(i) Calculate the mass flow rate to be used in the daily instrument check by following the procedures in paragraphs (i)(2)(i)(A) and (i)(2)(i)(B) of this section.

(A) For a specified population of equipment to be imaged by the instrument, determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level.

(B) Multiply the standard detection sensitivity level, corresponding to the selected monitoring frequency in Table 1 of subpart A of this part, by the mass fraction of detectable chemicals from the stream identified in paragraph (i)(2)(i)(A) of this section to determine the mass flow rate to be used in the daily instrument check, using the following equation.

$$E_{dic} = (E_{sds}) \sum_{i=1}^k x_i$$

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Where:

E_{dic} = Mass flow rate for the daily instrument check, grams per hour

x_i = Mass fraction of detectable chemical(s) i seen by the optical gas imaging instrument, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level, E_{sds} .

E_{sds} = Standard detection sensitivity level from Table 1 to subpart A, grams per hour

k = Total number of detectable chemicals emitted from the leaking equipment and seen by the optical gas imaging instrument.

(ii) Start the optical gas imaging instrument according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer's instructions.

(iii) Use any gas chosen by the user that can be viewed by the optical gas imaging instrument and that has a purity of no less than 98 percent.

(iv) Establish a mass flow rate by using the following procedures:

(A) Provide a source of gas where it will be in the field of view of the optical gas imaging instrument.

(B) Set up the optical gas imaging instrument at a recorded distance from the outlet or leak orifice of the flow meter that will not be exceeded in the actual performance of the leak survey. Do not exceed the operating parameters of the flow meter.

(C) Open the valve on the flow meter to set a flow rate that will create a mass emission rate equal to the mass rate specified in paragraph (i)(2)(i) of this section while observing the gas flow through the optical gas imaging instrument viewfinder. When an image of the gas emission is seen through the viewfinder at the required emission rate, make a record of the reading on the flow meter.

(v) Repeat the procedures specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each configuration of the optical gas imaging instrument used during the leak survey.

(vi) To use an alternative method to demonstrate daily instrument checks, apply to the Administrator for approval of the alternative under §60.13(i).

(3) Leak Survey Procedure. Operate the optical gas imaging instrument to image every regulated piece of equipment selected for this work practice in accordance with the instrument manufacturer's operating parameters. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

(4) Recordkeeping. You must keep the records described in paragraphs (i)(4)(i) through (i)(4)(vii) of this section:

(i) The equipment, processes, and facilities for which the owner or operator chooses to use the alternative work practice.

(ii) The detection sensitivity level selected from Table 1 to subpart A of this part for the optical gas imaging instrument.

(iii) The analysis to determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, as specified in paragraph (i)(2)(i)(A) of this section.

(iv) The technical basis for the mass fraction of detectable chemicals used in the equation in paragraph (i)(2)(i)(B) of this section.

(v) The daily instrument check. Record the distance, per paragraph (i)(2)(iv)(B) of this section, and the flow meter reading, per paragraph (i)(2)(iv)(C) of this section, at which the leak was imaged. Keep a video record of the daily instrument check for each configuration of the optical gas imaging instrument used during the leak survey (for example, the daily instrument check must be conducted for each lens used). The video record must include a time and date stamp for each daily instrument check. The video record must be kept for 5 years.

(vi) Recordkeeping requirements in the applicable subpart. A video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping requirements of the applicable subparts if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.

(vii) The results of the annual Method 21 screening required in paragraph (h)(7) of this section. Records must be kept for all regulated equipment specified in paragraph (h)(1) of this section. Records must identify the equipment screened, the screening value measured by Method 21, the time and date of the screening, and calibration information required in the existing applicable subpart.

(5) Reporting. Submit the reports required in the applicable subpart. Submit the records of the annual Method 21 screening required in paragraph (h)(7) of this section to the Administrator via e-mail to *CCG-AWP@EPA.GOV*.

[51 FR 2701, Jan. 21, 1986, as amended at 63 FR 24444, May 4, 1998; 65 FR 61752, Oct. 17, 2000; 73 FR 78209, Dec. 22, 2008]

[↑ Back to Top](#)

§60.19 General notification and reporting requirements.

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word "calendar" is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f)(1)(i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

[59 FR 12428, Mar. 16, 1994, as amended at 64 FR 7463, Feb. 12, 1998]

Table 1 to Subpart A of Part 60—Detection Sensitivity Levels (grams per hour)

Monitoring frequency per subpart^a	Detection sensitivity level
Bi-Monthly	60
Semi-Quarterly	85
Monthly	100

^aWhen this alternative work practice is used to identify leaking equipment, the owner or operator must choose one of the monitoring frequencies listed in this table in lieu of the monitoring frequency specified in the applicable subpart. Bi-monthly means every other month. Semi-quarterly means twice per quarter. Monthly means once per month.

[73 FR 78211, Dec. 22, 2008]

APPENDIX F - NSPS 40 CFR 60 SUBPART K

Federal Revision Date: 10/17/00

Subpart K—Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978

§ 60.110 Applicability and designation of affected facility.

- (a) Except as provided in §60.110(b), the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,412 liters (40,000 gallons).
- (b) This subpart does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.
- (c) Subject to the requirements of this subpart is any facility under paragraph (a) of this section which:
- (1) Has a capacity greater than 151, 416 liters (40,000 gallons), but not exceeding 246,052 liters (65,000 gallons), and commences construction or modification after March 8, 1974, and prior to May 19, 1978.
 - (2) Has a capacity greater than 246,052 liters (65,000 gallons) and commences construction or modification after June 11, 1973, and prior to May 19, 1978.

[42 FR 37937, July 25, 1977, as amended at 45 FR 23379, Apr. 4, 1980]

§ 60.111 Definitions.

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

- (a) *Storage vessel* means any tank, reservoir, or container used for the storage of petroleum liquids, but does not include:
- (1) Pressure vessels which are designed to operate in excess of 15 pounds per square inch gauge without emissions to the atmosphere except under emergency conditions,
 - (2) Subsurface caverns or porous rock reservoirs, or
 - (3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.
- (b) *Petroleum liquids* means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM D396–78, 89, 90, 92, 96, or 98, gas turbine fuel oils Nos. 2–GT through 4–GT as specified in ASTM D2880–78 or 96, or diesel fuel oils Nos. 2–D and 4–D as specified in ASTM D975–78, 96, or 98a. (These three methods are incorporated by reference—see §60.17.)
- (c) *Petroleum refinery* means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or reforming of unfinished petroleum derivatives.
- (d) *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.
- (e) *Hydrocarbon* means any organic compound consisting predominantly of carbon and hydrogen.
- (f) *Condensate* means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature and/or pressure and remains liquid at standard conditions.
- (g) *Custody transfer* means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.
- (h) *Drilling and production facility* means all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary nontransportation-related equipment used in the production of petroleum but does not include natural gasoline plants.
- (i) *True vapor pressure* means the equilibrium partial pressure exerted by a petroleum liquid as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from External Floating-Roof Tanks, Second Edition, February 1980 (incorporated by reference—see §60.17).

APPENDIX F - NSPS 40 CFR 60 SUBPART K

(j) *Floating roof* means a storage vessel cover consisting of a double deck, pontoon single deck, internal floating cover or covered floating roof, which rests upon and is supported by the petroleum liquid being contained, and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.

(k) *Vapor recovery system* means a vapor gathering system capable of collecting all hydrocarbon vapors and gases discharged from the storage vessel and a vapor disposal system capable of processing such hydrocarbon vapors and gases so as to prevent their emission to the atmosphere.

(l) *Reid vapor pressure* is the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids, except liquified petroleum gases, as determined by ASTM D323-82 or 94 (incorporated by reference—see §60.17).

[39 FR 9317, Mar. 8, 1974; 39 FR 13776, Apr. 17, 1974, as amended at 39 FR 20794, June 14, 1974; 45 FR 23379, Apr. 4, 1980; 48 FR 3737, Jan. 27, 1983; 52 FR 11429, Apr. 8, 1987; 65 FR 61755, Oct. 17, 2000]

§ 60.112 Standard for volatile organic compounds (VOC).

(a) The owner or operator of any storage vessel to which this subpart applies shall store petroleum liquids as follows:

(1) If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalents.

(2) If the true vapor pressure of the petroleum liquid as stored is greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a vapor recovery system or its equivalent.

[39 FR 9317, Mar. 8, 1974; 39 FR 13776, Apr. 17, 1974, as amended at 45 FR 23379, Apr. 4, 1980]

§ 60.113 Monitoring of operations.

(a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.

(b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).

(c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).

(d) The following are exempt from the requirements of this section:

(1) Each owner or operator of each affected facility which stores petroleum liquids with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).

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

[45 FR 23379, Apr. 4, 1980]

APPENDIX G - NSPS 40 CFR 60 SUBPART Ka

Federal Register Date: 12/14/00

Subpart Ka—Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984.

§ 60.110a Applicability and designation of affected facility.

- (a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel for petroleum liquids which has a storage capacity greater than 151,416 liters (40,000 gallons) that is used to store petroleum liquids for which construction is commenced after May 18, 1978.
- (b) Each petroleum liquid storage vessel with a capacity of less than 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer is not an affected facility and, therefore, is exempt from the requirements of this subpart.
- (c) *Alternative means of compliance* –
 - (1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§ 60.112a through 60.114a for storage vessels that are subject to this subpart that store petroleum liquids that, as stored, have a maximum true vapor pressure equal to or greater than 10.3 kPa (1.5 psia). Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.
 - (2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (c)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.

§ 60.111a Definitions.

In addition to the terms and their definitions listed in the Act and subpart A of this part the following definitions apply in this subpart:

- (a) *Storage vessel* means each tank, reservoir, or container used for the storage of petroleum liquids, but does not include:
 - (1) Pressure vessels which are designed to operate in excess of 204.9 kPa (15 psig) without emissions to the atmosphere except under emergency conditions.
 - (2) Subsurface caverns or porous rock reservoirs, or
 - (3) Underground tanks if the total volume of petroleum liquids added to and taken from a tank annually does not exceed twice the volume of the tank.
- (b) *Petroleum liquids* means petroleum, condensate, and any finished or intermediate products manufactured in a petroleum refinery but does not mean Nos. 2 through 6 fuel oils as specified in ASTM D396–78, 89, 90, 92, 96, or 98 gas turbine fuel oils Nos. 2–GT through 4–GT as specified in ASTM D2880–78 or 96, gas turbine fuel oils Nos. 2–GT through 4–GT as specified in ASTM D2880–78 or 96, or diesel fuel oils Nos. 2–D and 4–D as specified in ASTM D975–78, 96 or 98a. (These three methods are incorporated by reference— see § 60.17.)
- (c) *Petroleum refinery* means each facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, extracting, or re-forming of unfinished petroleum derivatives.
- (d) *Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.
- (e) *Condensate* means hydrocarbon liquid separated from natural gas which condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.
- (f) *True vapor pressure* means the equilibrium partial pressure exerted by a petroleum liquid such as determined in accordance with methods described in American Petroleum Institute Bulletin 2517, Evaporation Loss from External Floating-Roof Tanks, Second Edition, February 1980 (incorporated by reference—see § 60.17).

APPENDIX G - NSPS 40 CFR 60 SUBPART Ka

- (g) *Reid vapor pressure* is the absolute vapor pressure of volatile crude oil and nonviscous petroleum liquids, except liquified petroleum gases, as determined by ASTM D323–82 or 94 (incorporated by reference—see § 60.17).
- (h) *Liquid-mounted seal* means a foam or liquid-filled primary seal mounted in contact with the liquid between the tank wall and the floating roof continuously around the circumference of the tank.
- (i) *Metallic shoe seal* includes but is not limited to a metal sheet held vertically against the tank wall by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.
- (j) *Vapor-mounted seal* means a foam-filled primary seal mounted continuously around the circumference of the tank so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the tank wall, the liquid surface, and the floating roof.
- (k) *Custody transfer* means the transfer of produced petroleum and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.

[45 FR 23379, Apr. 4, 1980, as amended at 48 FR 3737, Jan. 27, 1983; 52 FR 11429, Apr. 8, 1987]

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

- (a) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure equal to or greater than 10.3 kPa (1.5 psia) but not greater than 76.6 kPa (11.1 psia) shall equip the storage vessel with one of the following:
 - (1) An external floating roof, consisting of a pontoon-type or double-deck-type cover that rests on the surface of the liquid contents and is equipped with a closure device between the tank § 60.112a wall and the roof edge. Except as provided in paragraph (a)(1)(ii)(D) of this section, the closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal and the upper seal is referred to as the secondary seal. The roof is to be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.
 - (i) The primary seal is to be either a metallic shoe seal, a liquid-mounted seal, or a vapor-mounted seal. Each seal is to meet the following requirements:
 - (A) The accumulated area of gaps between the tank wall and the metallic shoe seal or the liquid-mounted seal shall not exceed 212 cm² per meter of tank diameter (10.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 3.81 cm (1 1/2 in).
 - (B) The accumulated area of gaps between the tank wall and the vapor-mounted seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (1/2 in).
 - (C) One end of the metallic shoe is to extend into the stored liquid and the other end is to extend a minimum vertical distance of 61 cm (24 in) above the stored liquid surface.
 - (D) There are to be no holes, tears, or other openings in the shoe, seal fabric, or seal envelope.
 - (ii) The secondary seal is to meet the following requirements:
 - (A) The secondary seal is to be installed above the primary seal so that it completely covers the space between the roof edge and the tank wall except as provided in paragraph (a)(1)(ii)(B) of this section.
 - (B) The accumulated area of gaps between the tank wall and the secondary seal used in combination with a metallic shoe or liquid-mounted primary seal shall not exceed 21.2 cm² per meter of tank diameter (1.0 in² per ft. of tank diameter) and the width of any portion of any gap shall not exceed 1.27 cm (1/2 in.). There shall be no gaps between the tank wall and the secondary seal used in combination with a vapor-mounted primary seal.
 - (C) There are to be no holes, tears or other openings in the seal or seal fabric.
 - (D) The owner or operator is exempted from the requirements for secondary seals and the secondary seal gap criteria when performing gap measurements or inspections of the primary seal.
 - (iii) Each opening in the roof except for automatic bleeder vents and rim space vents is to provide a projection below the liquid surface. Each opening in the roof except for automatic bleeder vents, rim space vents and leg sleeves is to be equipped with a cover, seal or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use or as described in paragraph (a)(1)(iv) of this section. Automatic bleeder vents are to be closed at all times when the roof is floating, except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting.

APPENDIX G - NSPS 40 CFR 60 SUBPART Ka

- (iv) Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.
- (2) A fixed roof with an internal floating type cover equipped with a continuous closure device between the tank wall and the cover edge. The cover is to be floating at all times, (i.e., off the leg supports) except during initial fill and when the tank is completely emptied and subsequently refilled. The process of emptying and refilling when the cover is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible. Each opening in the cover except for automatic bleeder vents and the rim space vents is to provide a projection below the liquid surface. Each opening in the cover except for automatic bleeder vents, rim space vents, stub drains and leg sleeves is to be equipped with a cover, seal, or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the cover is floating except when the cover is being floated off or is being landed on the leg supports. Rim vents are to be set to open only when the cover is being floated off the leg supports or at the manufacturer's recommended setting.
- (3) A vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.
- (4) A system equivalent to those described in paragraphs (a)(1), (a)(2), or (a)(3) of this section as provided in § 60.114a.
- (b) The owner or operator of each storage vessel to which this subpart applies which contains a petroleum liquid which, as stored, has a true vapor pressure greater than 76.6 kPa (11.1 psia), shall equip the storage vessel with a vapor recovery system which collects all VOC vapors and gases discharged from the storage vessel, and a vapor return or disposal system which is designed to process such VOC vapors and gases so as to reduce their emission to the atmosphere by at least 95 percent by weight.

[45 FR 23379, Apr. 4, 1980, as amended at 45 FR 83229, Dec. 18, 1980]

§ 60.113a Testing and procedures.

- (a) Except as provided in § 60.8(b) compliance with the standard prescribed in § 60.112a shall be determined as follows or in accordance with an equivalent procedure as provided in § 60.114a.
 - (1) The owner or operator of each storage vessel to which this subpart applies which has an external floating roof shall meet the following requirements:
 - (i) Determine the gap areas and maximum gap widths between the primary seal and the tank wall and between the secondary seal and the tank wall according to the following frequency:
 - (A) For primary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every five years thereafter. All primary seal inspections or gap measurements which require the removal or dislodging of the secondary seal shall be accomplished as rapidly as possible and the secondary seal shall be replaced as soon as possible.
 - (B) For secondary seals, gap measurements shall be performed within 60 days of the initial fill with petroleum liquid and at least once every year thereafter.
 - (C) If any storage vessel is out of service for a period of one year or more, subsequent refilling with petroleum liquid shall be considered initial fill for the purposes of paragraphs (a)(1)(i)(A) and (a)(1)(i)(B) of this section.
 - (D) Keep records of each gap measurement at the plant for a period of at least 2 years following the date of measurement. Each record shall identify the vessel on which the measurement was performed and shall contain the date of the seal gap measurement, the raw data obtained in the measurement process required by paragraph (a)(1)(ii) of this section and the calculation required by paragraph (a)(1)(iii) of this section.
 - (E) If either the seal gap calculated in accord with paragraph (a)(1)(iii) of this section or the measured maximum seal gap exceeds the limitations specified by § 60.112a of this subpart, a report shall be furnished to the Administrator within 60 days of the date of measurements. The report shall identify the vessel and list each reason why the vessel did not meet the specifications of § 60.112a. The report shall also describe the actions necessary to bring the storage vessel into compliance with the specifications of § 60.112a.
 - (ii) Determine gap widths in the primary and secondary seals individually by the following procedures:
 - (A) Measure seal gaps, if any, at one or more floating roof levels when the roof is floating off the roof leg supports.
 - (B) Measure seal gaps around the entire circumference of the tank in each place where a (1/8)" diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the tank wall and measure the circumferential distance of each such location.

APPENDIX G - NSPS 40 CFR 60 SUBPART Ka

- (C) The total surface area of each gap described in paragraph (a)(1)(ii)(B) of this section shall be determined by using probes of various widths to accurately measure the actual distance from the tank wall to the seal and multiplying each such width by its respective circumferential distance.
 - (iii) Add the gap surface area of each gap location for the primary seal and the secondary seal individually. Divide the sum for each seal by the nominal diameter of the tank and compare each ratio to the appropriate ratio in the standard in § 60.112a(a)(1)(i) and § 60.112a(a)(1)(ii).
 - (iv) Provide the Administrator 30 days prior notice of the gap measurement to afford the Administrator the opportunity to have an observer present.
- (2) The owner or operator of each storage vessel to which this subpart applies which has a vapor recovery and return or disposal system shall provide the following information to the Administrator on or before the date on which construction of the storage vessel commences:
- (i) Emission data, if available, for a similar vapor recovery and return or disposal system used on the same type of storage vessel, which can be used to determine the efficiency of the system. A complete description of the emission measurement method used must be included.
 - (ii) The manufacturer's design specifications and estimated emission reduction capability of the system.
 - (iii) The operation and maintenance plan for the system.
 - (iv) Any other information which will be useful to the Administrator in evaluating the effectiveness of the system in reducing VOC emissions.

[45 FR 23379, Apr. 4, 1980, as amended at 52 FR 11429, Apr. 8, 1987]

§ 60.114a Alternative means of emission limitation.

- (a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in § 60.112a, the Administrator will publish in the FEDERAL REGISTER a notice permitting the use of the alternative means for purposes of compliance with that requirement.
- (b) Any notice under paragraph (a) of this section will be published only after notice and an opportunity for a hearing.
- (c) Any person seeking permission under this section shall submit to the Administrator a written application including:
 - (1) An actual emissions test that uses a full-sized or scale-model storage vessel that accurately collects and measures all VOC emissions from a given control device and that accurately simulates wind and accounts for other emission variables such as temperature and barometric pressure.
 - (2) An engineering evaluation that the Administrator determines is an accurate method of determining equivalence.
- (d) The Administrator may condition the permission on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as specified in § 60.112a.
- (e) The primary vapor-mounted seal in the "Volume-Maximizing Seal" manufactured by R.F.I. Services Corporation is approved as equivalent to the vapor-mounted seal required by § 60.112a(a)(1)(i) and must meet the gap criteria specified in § 60.112a(a)(1)(i)(B). There shall be no gaps between the tank wall and any secondary seal used in conjunction with the primary seal in the "Volume-Maximizing Seal".

[52 FR 11429, Apr. 8, 1987]

§ 60.115a Monitoring of operations.

- (a) Except as provided in paragraph (d) of this section, the owner or operator subject to this subpart shall maintain a record of the petroleum liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period.
- (b) Available data on the typical Reid vapor pressure and the maximum expected storage temperature of the stored product may be used to determine the maximum true vapor pressure from nomographs contained in API Bulletin 2517, unless the Administrator specifically requests that the liquid be sampled, the actual storage temperature determined, and the Reid vapor pressure determined from the sample(s).
- (c) The true vapor pressure of each type of crude oil with a Reid vapor pressure less than 13.8 kPa (2.0 psia) or whose physical properties preclude determination by the recommended method is to be determined from available data and recorded if the estimated true vapor pressure is greater than 6.9 kPa (1.0 psia).
- (d) The following are exempt from the requirements of this section:

APPENDIX G - NSPS 40 CFR 60 SUBPART Ka

- (1) Each owner or operator of each storage vessel storing a petroleum liquid with a Reid vapor pressure of less than 6.9 kPa (1.0 psia) provided the maximum true vapor pressure does not exceed 6.9 kPa (1.0 psia).
- (2) 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), or a closed vent system and control device meeting the specifications of 40 CFR 65.42(b)(4), (b)(5), or (c).

Federal Register Date: October 15, 2003

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

§ 60.110b Applicability and designation of affected facility.

- (a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m³) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.
- (b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151m³ storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m³ but less than 151 m³ storing a liquid with a maximum true vapor pressure less than 15.0 kPa.
- (c) [Reserved]
- (d) This subpart does not apply to the following:
 - (1) Vessels at coke oven by-product plants.
 - (2) Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.
 - (3) Vessels permanently attached to mobile vehicles such as trucks, 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.
 - (8) Vessels subject to subpart GGGG of 40 CFR part 63.
- (e) *Alternative means of compliance* –
 - (1) *Option to comply with part 65.* Owners or operators may choose to comply with 40 CFR part 65, subpart C, to satisfy the requirements of §§ 60.112b through 60.117b for storage vessels that are subject to this subpart that meet the specifications in paragraphs (e)(1)(i) and (ii) of this section. When choosing to comply with 40 CFR part 65, subpart C, the monitoring requirements of § 60.116b(c), (e), (f)(1), and (g) still apply. Other provisions applying to owners or operators who choose to comply with 40 CFR part 65 are provided in 40 CFR 65.1.
 - (i) A storage vessel with a design capacity greater than or equal to 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa; or
 - (ii) A storage vessel with a design capacity greater than 75 m³ but less than 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa.
 - (2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart C, must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for those storage vessels. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2) do not apply to owners or operators of storage vessels complying with 40 CFR part 65, subpart C, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart C, must comply with 40 CFR part 65, subpart A.
 - (3) *Internal floating roof report.* If an owner or operator installs an internal floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the Administrator stating that the control equipment meets the specifications of 40 CFR 65.43. This report shall be an attachment to the notification required by 40 CFR 65.5(b).
 - (4) *External floating roof report.* If an owner or operator installs an external floating roof and, at initial startup, chooses to comply with 40 CFR part 65, subpart C, a report shall be furnished to the

Administrator stating that the control equipment meets the specifications of 40 CFR 65.44. This report shall be an attachment to the notification required by 40 CFR 65.5(b).

§ 60.111b Definitions.

Terms used in this subpart are defined in the Act, in subpart A of this part, or in this subpart as follows:

Bulk gasoline plant means any gasoline distribution facility that has a gasoline throughput less than or equal to 75,700 liters per day. Gasoline throughput shall be the maximum calculated design throughput as may be limited by compliance with an enforceable condition under Federal requirement or Federal, State or local law, and discoverable by the Administrator and any other person.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature or pressure, or both, and remains liquid at standard conditions.

Custody transfer means the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

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

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

Maximum true vapor pressure means the equilibrium partial pressure exerted by the volatile organic compounds (as defined in 40 CFR 51.100) in the stored VOL at the temperature equal to the highest calendar-month average of the VOL storage temperature for VOL's stored above or below the ambient temperature or at the local maximum monthly average temperature as reported by the National Weather Service for VOL's stored at the ambient temperature, as determined:

- (1) In accordance with methods de-scribed 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, 96, or 97 (incorporated by reference— see § 60.17);
- (4) Any other method approved by the Administrator.

Reid vapor pressure means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquified petroleum gases, as determined by ASTM D323–82 or 94 (incorporated by reference—see § 60.17).

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

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

Process tank means a tank that is used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations.

Storage vessel means each tank, reservoir, or container used for the storage of volatile organic liquids but does not include:

- (1) Frames, housing, auxiliary supports, or other components that are not directly involved in the containment of liquids or vapors;
- (2) Subsurface caverns or porous rock reservoirs; or
- (3) Process tanks.

Volatile organic liquid (VOL) means any organic liquid which can emit volatile organic compounds (as defined in 40 CFR 51.100) into the atmosphere.

Waste means any liquid resulting from industrial, commercial, mining or agricultural operations, or from community activities that is discarded or is being accumulated, stored, or physically, chemically, or biologically treated prior to being discarded or recycled.

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

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

- (a) The owner or operator of each storage vessel either with a design capacity greater than or equal to 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 5.2 kPa but less than 76.6 kPa or with a design capacity greater than or equal to 75 m³ but less than 151 m³ containing a VOL that, as stored, has a maximum true vapor pressure equal to or greater than 27.6 kPa but less than 76.6 kPa, shall equip each storage vessel with one of the following:
- (1) A fixed roof in combination with an internal floating roof meeting the following specifications:
- (i) The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal floating roof shall be floating on the liquid surface at all times, except during initial fill and during those intervals when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible.
 - (ii) Each internal floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof:
 - (A) A foam- or liquid-filled seal mounted in contact with the liquid (liquid-mounted seal). A liquid-mounted seal means a foam- or liquid-filled seal mounted in contact with the liquid between the wall of the storage vessel and the floating roof continuously around the circumference of the tank.
 - (B) Two seals mounted one above the other so that each forms a continuous closure that completely covers the space between the wall of the storage vessel and the edge of the internal floating roof. The lower seal may be vapor-mounted, but both must be continuous.
 - (C) A mechanical shoe seal. A mechanical shoe seal is a metal sheet held vertically against the wall of the storage vessel by springs or weighted levers and is connected by braces to the floating roof. A flexible coated fabric (envelope) spans the annular space between the metal sheet and the floating roof.
 - (iii) Each opening in a noncontact internal floating roof except for automatic bleeder vents (vacuum breaker vents) and the rim space vents is to provide a projection below the liquid surface.
 - (iv) Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use.
 - (v) Automatic bleeder vents shall be equipped with a gasket and are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports.
 - (vi) Rim space vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting.
 - (vii) Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The sample well shall have a slit fabric cover that covers at least 90 percent of the opening.
 - (viii) Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover.

- (ix) Each penetration of the internal floating roof that allows for passage of a ladder shall have a gasketed sliding cover.
 - (2) An external floating roof. An external floating roof means a pontoon-type or double-deck type cover that rests on the liquid surface in a vessel with no fixed roof. Each external floating roof must meet the following specifications:
 - (i) Each external floating roof shall be equipped with a closure device between the wall of the storage vessel and the roof edge. The closure device is to consist of two seals, one above the other. The lower seal is referred to as the primary seal, and the upper seal is referred to as the secondary seal.
 - (A) The primary seal shall be either a mechanical shoe seal or a liquid-mounted seal. Except as provided in § 60.113b(b)(4), the seal shall completely cover the annular space between the edge of the floating roof and tank wall.
 - (B) The secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion except as allowed in § 60.113b(b)(4).
 - (ii) Except for automatic bleeder vents and rim space vents, each opening in a noncontact external floating roof shall provide a projection below the liquid surface. Except for automatic bleeder vents, rim space vents, roof drains, and leg sleeves, each opening in the roof is to be equipped with a gasketed cover, seal, or lid that is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. Automatic bleeder vents are to be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. Rim vents are to be set to open when the roof is being floated off the roof legs supports or at the manufacturer's recommended setting. Automatic bleeder vents and rim space vents are to be gasketed. Each emergency roof drain is to be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening.
 - (iii) The roof shall be floating on the liquid at all times (i.e., off the roof leg supports) except during initial fill until the roof is lifted off leg supports and when the tank is completely emptied and subsequently refilled. The process of filling, emptying, or refilling when the roof is resting on the leg supports shall be continuous and shall be accomplished as rapidly as possible.
 - (3) A closed vent system and control device meeting the following specifications:
 - (i) The closed vent system shall be designed to collect all VOC vapors and gases discharged from the storage vessel and operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections, as determined in part 60, subpart VV, § 60.485(b).
 - (ii) The control device shall be designed and operated to reduce inlet VOC emissions by 95 percent or 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 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.
- (1) Submit for approval by the Administrator as an attachment to the notification required by § 60.7(a)(1) or, if the facility is exempt from § 60.7(a)(1), as an attachment to the notification required by § 60.7(a)(2), an operating plan containing the information listed below.
 - (i) Documentation demonstrating that the control device will achieve the required control efficiency during maximum loading conditions. This documentation is to include a description of the gas stream which enters the control device, including flow and VOC content under varying liquid level conditions (dynamic and static) and manufacturer's design specifications for the control device. If the control device or the closed vent capture system receives vapors, gases, or liquids other than fuels from sources that are not designated sources under this subpart, the efficiency demonstration is to include consideration of all vapors, gases, and liquids received by the closed vent capture system and control device. If an enclosed combustion device with a minimum residence time of 0.75 seconds and a minimum temperature of 816 °C is used to meet the 95 percent requirement, documentation that those conditions will exist is sufficient to meet the requirements of this paragraph.
 - (ii) A description of the parameter or parameters to be monitored to ensure that the control device will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).
 - (2) Operate the closed vent system and control device and monitor the parameters of the closed vent system and control device in accordance with the operating plan submitted to the Administrator in accordance with paragraph (c)(1) of this section, unless the plan was modified by the Administrator during the review process. In this case, the modified plan applies.
- (d) The owner or operator of each source that is equipped with a closed vent system and a flare to meet the requirements in § 60.112b (a)(3) or (b)(2) shall meet the requirements as specified in the general control device requirements, § 60.18 (e) and (f).

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

§ 60.114b Alternative means of emission limitation.

- (a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved by any requirement in § 60.112b, the Administrator will publish in 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.

- (a) After installing control equipment in accordance with § 60.112b(a)(1) (fixed roof and internal floating roof), the owner or operator shall meet the following requirements.
 - (1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(1) and § 60.113b(a)(1). This report shall be an attachment to the notification required by § 60.7(a)(3).
 - (2) Keep a record of each inspection performed as required by § 60.113b (a)(1), (a)(2), (a)(3), and (a)(4). Each record shall identify the storage vessel on which the inspection was performed and shall contain the date the vessel was inspected and the observed condition of each component of the control equipment (seals, internal floating roof, and fittings).
 - (3) If any of the conditions described in § 60.113b(a)(2) are detected during the annual visual inspection required by § 60.113b(a)(2), a report shall be furnished to the Administrator within 30 days of the inspection. Each report shall identify the storage vessel, the nature of the defects, and the date the storage vessel was emptied or the nature of and date the repair was made.
 - (4) After each inspection required by § 60.113b(a)(3) that finds holes or tears in the seal or seal fabric, or defects in the internal floating roof, or other control equipment defects listed in § 60.113b(a)(3)(ii), a report shall be furnished to the Administrator within 30 days of the inspection. The report shall identify the storage vessel and the reason it did not meet the specifications of § 61.112b(a)(1) or § 60.113b(a)(3) and list each repair made.
- (b) After installing control equipment in accordance with § 61.112b(a)(2) (external floating roof), the owner or operator shall meet the following requirements.
 - (1) Furnish the Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of § 60.112b(a)(2) and § 60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by § 60.7(a)(3).
 - (2) Within 60 days of performing the seal gap measurements required by § 60.113b(b)(1), furnish the Administrator with a report that contains:
 - (i) The date of measurement.
 - (ii) The raw data obtained in the measurement.
 - (iii) The calculations described in § 60.113b (b)(2) and (b)(3).
 - (3) Keep a record of each gap measurement performed as required by § 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:

- (i) The date of measurement.
 - (ii) The raw data obtained in the measurement.
 - (iii) The calculations described in § 60.113b (b)(2) and (b)(3).
 - (4) After each seal gap measurement that detects gaps exceeding the limitations specified by § 60.113b(b)(4), submit a report to the Administrator within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of this section and the date the vessel was emptied or the repairs made and date of repair.
- (c) After installing control equipment in accordance with § 60.112b (a)(3) or (b)(1) (closed vent system and control device other than a flare), the owner or operator shall keep the following records.
- (1) A copy of the operating plan.
 - (2) A record of the measured values of the parameters monitored in accordance with § 60.113b(c)(2).
- (d) After installing a closed vent system and flare to comply with § 60.112b, the owner or operator shall meet the following requirements.
- (1) A report containing the measurements required by § 60.18(f) (1), (2), (3), (4), (5), and (6) shall be furnished to the Administrator as required by § 60.8 of the General Provisions. This report shall be submitted within 6 months of the initial start-up date.
 - (2) Records shall be kept of all periods of operation during which the flare pilot flame is absent.
 - (3) Semiannual reports of all periods recorded under § 60.115b(d)(2) in which the pilot flame was absent shall be furnished to the Administrator.

§ 60.116b Monitoring of operations.

- (a) The owner or operator shall keep copies of all records required by this section, except for the record required by paragraph (b) of this section, for at least 2 years. The record required by paragraph (b) of this section will be kept for the life of the source.
- (b) The owner or operator of each storage vessel as specified in § 60.110b(a) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.
- (c) Except as provided in paragraphs (f) and (g) of this section, the owner or operator of each storage vessel either with a design capacity greater than or equal to 151 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, 96, or 97 (incorporated by reference— see § 60.17); or
 - (iii) Measured by an appropriate method approved by the Administrator; or
 - (iv) Calculated by an appropriate method approved by the Administrator.
- (f) The owner or operator of each vessel storing a waste mixture of indeterminate or variable composition shall be subject to the following requirements.
- (1) Prior to the initial filling of the vessel, the highest maximum true vapor pressure for the range of anticipated liquid compositions to be stored will be determined using the methods described in paragraph (e) of this section.
 - (2) For vessels in which the vapor pressure of the anticipated liquid composition is above the cutoff for monitoring but below the cutoff for controls as defined in §60.112b(a), an initial physical test of the vapor pressure is required; and a physical test at least once every 6 months thereafter is required as determined by the following methods:
 - (i) ASTM Method D2879–83, 96, or 97 (incorporated by reference—see § 60.17); or
 - (ii) ASTM Method D323–82 or 94 (incorporated by reference—see §60.17); or
 - (iii) As measured by an appropriate method as approved by the Administrator.
- (g) The owner or operator of each vessel equipped with a closed vent system and control device meeting the specifications of § 60.112b or with emissions reduction equipment as specified in 40 CFR 65.5(b)(4), (b)(5), (b)(6), or (c) 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]

Federal Register Date: December 19, 2003

40 CFR Part 60, Subpart XX - Standards of Performance for Bulk Gasoline Terminals

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

§ 60.500 Applicability and designation of affected facility.

- (a) The affected facility to which the provisions of this subpart apply is the total of all the loading racks at a bulk gasoline terminal which deliver liquid product into gasoline tank trucks.
- (b) Each facility under paragraph (a) of this section, the construction or modification of which is commenced after December 17, 1980, is subject to the provisions of this subpart.
- (c) For purposes of this subpart, any replacement of components of an existing facility, described in paragraph (a) of this section, commenced before August 18, 1983 in order to comply with any emission standard adopted by a State or political subdivision thereof will not be considered a reconstruction under the provisions of 40 CFR 60.15.

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

§ 60.501 Definitions.

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

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

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

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

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

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater which is used as a fuel for internal combustion engines.

Gasoline tank truck means a delivery tank truck used at bulk gasoline terminals which is loading gasoline or which has loaded gasoline on the immediately previous load.

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

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

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

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

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

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

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

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

[48 FR 37590, Aug. 18, 1983, as amended at 65 FR 61763, Oct. 17, 2000; 68 FR 70965, Dec. 19, 2003]

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

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

- (a) Each affected facility shall be equipped with a vapor collection system designed to collect the total organic compounds vapors displaced from tank trucks during product loading.
- (b) The emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline tank trucks are not to exceed 35 milligrams of total organic compounds per liter of gasoline loaded, except as noted in paragraph (c) of this section.
- (c) For each affected facility equipped with an existing vapor processing system, the emissions to the atmosphere from the vapor collection system due to the loading of liquid product into gasoline tank trucks are not to exceed 80 milligrams of total organic compounds per liter of gasoline loaded.
- (d) Each vapor collection system shall be designed to prevent any total organic compounds vapors collected at one loading rack from passing to another loading rack.
- (e) Loadings of liquid product into gasoline tank trucks shall be limited to vapor-tight gasoline tank trucks using the following procedures:
 - (1) The owner or operator shall obtain the vapor tightness documentation described in §60.505(b) for each gasoline tank truck which is to be loaded at the affected facility.
 - (2) The owner or operator shall require the tank identification number to be recorded as each gasoline tank truck is loaded at the affected facility.
 - (3)
 - (i) The owner or operator shall cross-check each tank identification number obtained in paragraph (e)(2) of this section with the file of tank vapor tightness documentation within 2 weeks after the corresponding tank is loaded, unless either of the following conditions is maintained:
 - (A) If less than an average of one gasoline tank truck per month over the last 26 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed each quarter; or
 - (B) If less than an average of one gasoline tank truck per month over the last 52 weeks is loaded without vapor tightness documentation then the documentation cross-check shall be performed semiannually.
 - (ii) If either the quarterly or semiannual cross-check provided in paragraphs (e)(3)(i) (A) through (B) of this section reveals that these conditions were not maintained, the source must return to biweekly monitoring until such time as these conditions are again met.
 - (4) The terminal owner or operator shall notify the owner or operator of each non-vapor-tight gasoline tank truck loaded at the affected facility within 1 week of the documentation cross-check in paragraph (e)(3) of this section.
 - (5) The terminal owner or operator shall take steps assuring that the nonvapor-tight gasoline tank truck will not be reloaded at the affected facility until vapor tightness documentation for that tank is obtained.
 - (6) Alternate procedures to those described in paragraphs (e)(1) through (5) of this section for limiting gasoline tank truck loadings may be used upon application to, and approval by, the Administrator.
- (f) The owner or operator shall act to assure that loadings of gasoline tank trucks at the affected facility are made only into tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.
- (g) The owner or operator shall act to assure that the terminal's and the tank truck's vapor collection systems are connected during each loading of a gasoline tank truck at the affected facility. Examples of actions to accomplish this include training drivers in the hookup procedures and posting visible reminder signs at the affected loading racks.

- (h) The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the delivery tank from exceeding 4,500 pascals (450 mm of water) during product loading. This level is not to be exceeded when measured by the procedures specified in §60.503(d).
- (i) No pressure-vacuum vent in the bulk gasoline terminal's vapor collection system shall begin to open at a system pressure less than 4,500 pascals (450 mm of water).
- (j) Each calendar month, the vapor collection system, the vapor processing system, and each loading rack handling gasoline shall be inspected during the loading of gasoline tank trucks for total organic compounds liquid or vapor leaks. For purposes of this paragraph, detection methods incorporating sight, sound, or smell are acceptable. Each detection of a leak shall be recorded and the source of the leak repaired within 15 calendar days after it is detected.

[48 FR 37590, Aug. 18, 1983; 48 FR 56580, Dec. 22, 1983, as amended at 54 FR 6678, Feb. 14, 1989; 64 FR 7466, Feb. 12, 1999]

§ 60.503 Test methods and procedures.

- (a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). The three-run requirement of §60.8(f) does not apply to this subpart.
- (b) Immediately before the performance test required to determine compliance with §60.502 (b), (c), and (h), the owner or operator shall use Method 21 to monitor for leakage of vapor all potential sources in the terminal's vapor collection system equipment while a gasoline tank truck is being loaded. The owner or operator shall repair all leaks with readings of 10,000 ppm (as methane) or greater before conducting the performance test.
- (c) The owner or operator shall determine compliance with the standards in §60.502 (b) and (c) as follows:
 - (1) The performance test shall be 6 hours long during which at least 300,000 liters of gasoline is loaded. If this is not possible, the test may be continued the same day until 300,000 liters of gasoline is loaded or the test may be resumed the next day with another complete 6-hour period. In the latter case, the 300,000-liter criterion need not be met. However, as much as possible, testing should be conducted during the 6-hour period in which the highest throughput normally occurs.
 - (2) If the vapor processing system is intermittent in operation, the performance test shall begin at a reference vapor holder level and shall end at the same reference point. The test shall include at least two startups and shutdowns of the vapor processor. If this does not occur under automatically controlled operations, the system shall be manually controlled.
 - (3) The emission rate (E) of total organic compounds shall be computed using the following equation:

$$E = K \sum_{i=1}^n (V_{esi} C_{ei}) / (L 10^6)$$

where:

E = emission rate of total organic compounds, mg/liter of gasoline loaded.

V_{esi} = volume of air-vapor mixture exhausted at each interval "i", scm.

C_{ei} = concentration of total organic compounds at each interval "i", ppm.

L = total volume of gasoline loaded, liters.

n = number of testing intervals.

i = emission testing interval of 5 minutes.

K = density of calibration gas, 1.83×10⁶ for propane and 2.41×10⁶ for butane, mg/scm.

- (4) The performance test shall be conducted in intervals of 5 minutes. For each interval "i", readings from each measurement shall be recorded, and the volume exhausted (V_{esi}) and the corresponding average total organic compounds concentration (C_{ei}) shall be determined. The sampling system response time shall be considered in determining the average total organic compounds concentration corresponding to the volume exhausted.
- (5) The following methods shall be used to determine the volume (V_{esi}) air-vapor mixture exhausted at each interval:
 - (i) Method 2B shall be used for combustion vapor processing systems.
 - (ii) Method 2A shall be used for all other vapor processing systems.
- (6) Method 25A or 25B shall be used for determining the total organic compounds concentration (C_{ei}) at each interval. The calibration gas shall be either propane or butane. The owner or operator may exclude the methane and ethane content in the exhaust vent by any method (e.g., Method 18) approved by the Administrator.

- (7) To determine the volume (L) of gasoline dispensed during the performance test period at all loading racks whose vapor emissions are controlled by the processing system being tested, terminal records or readings from gasoline dispensing meters at each loading rack shall be used.
- (d) The owner or operator shall determine compliance with the standard in §60.502(h) as follows:
 - (1) A pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument), capable of measuring up to 500 mm of water gauge pressure with ± 2.5 mm of water precision, shall be calibrated and installed on the terminal's vapor collection system at a pressure tap located as close as possible to the connection with the gasoline tank truck.
 - (2) During the performance test, the pressure shall be recorded every 5 minutes while a gasoline truck is being loaded; the highest instantaneous pressure that occurs during each loading shall also be recorded. Every loading position must be tested at least once during the performance test.
- (e) The performance test requirements of paragraph (c) of this section do not apply to flares defined in §60.501 and meeting the requirements in §60.18(b) through (f). The owner or operator shall demonstrate that the flare and associated vapor collection system is in compliance with the requirements in §§60.18(b) through (f) and 60.503(a), (b), and (d).
- (f) The owner or operator shall use alternative test methods and procedures in accordance with the alternative test method provisions in §60.8(b) for flares that do not meet the requirements in §60.18(b).

[54 FR 6678, Feb. 14, 1989; 54 FR 21344, Feb. 14, 1989, as amended at 68 FR 70965, Dec. 19, 2003]

§ 60.504 [Reserved]

§ 60.505 Reporting and recordkeeping.

- (a) The tank truck vapor tightness documentation required under §60.502(e)(1) shall be kept on file at the terminal in a permanent form available for inspection.
- (b) The documentation file for each gasoline tank truck shall be updated at least once per year to reflect current test results as determined by Method 27. This documentation shall include, as a minimum, the following information:
 - (1) Test title: Gasoline Delivery Tank Pressure Test—EPA Reference Method 27.
 - (2) Tank owner and address.
 - (3) Tank identification number.
 - (4) Testing location.
 - (5) Date of test.
 - (6) Tester name and signature.
 - (7) Witnessing inspector, if any: Name, signature, and affiliation.
 - (8) Test results: Actual pressure change in 5 minutes, mm of water (average for 2 runs).
- (c) A record of each monthly leak inspection required under §60.502(j) shall be kept on file at the terminal for at least 2 years. Inspection records shall include, as a minimum, the following information:
 - (1) Date of inspection.
 - (2) Findings (may indicate no leaks discovered; or location, nature, and severity of each leak).
 - (3) Leak determination method.
 - (4) Corrective action (date each leak repaired; reasons for any repair interval in excess of 15 days).
 - (5) Inspector name and signature.
- (d) The terminal owner or operator shall keep documentation of all notifications required under §60.502(e)(4) on file at the terminal for at least 2 years.
- (e) As an alternative to keeping records at the terminal of each gasoline cargo tank test result as required in paragraphs (a), (c), and (d) of this section, an owner or operator may comply with the requirements in either paragraph (e)(1) or (2) of this section.
 - (1) An electronic copy of each record is instantly available at the terminal.
 - (i) The copy of each record in paragraph (e)(1) of this section is an exact duplicate image of the original paper record with certifying signatures.

- (ii) The permitting authority is notified in writing that each terminal using this alternative is in compliance with paragraph (e)(1) of this section.
- (2) For facilities that utilize a terminal automation system to prevent gasoline cargo tanks that do not have valid cargo tank vapor tightness documentation from loading (*e.g.*, via a card lock-out system), a copy of the documentation is made available (*e.g.*, via facsimile) for inspection by permitting authority representatives during the course of a site visit, or within a mutually agreeable time frame.
 - (i) The copy of each record in paragraph (e)(2) of this section is an exact duplicate image of the original paper record with certifying signatures.
 - (ii) The permitting authority is notified in writing that each terminal using this alternative is in compliance with paragraph (e)(2) of this section.
- (f) The owner or operator of an affected facility shall keep records of all replacements or additions of components performed on an existing vapor processing system for at least 3 years.

[48 FR 37590, Aug. 18, 1983; 48 FR 56580, Dec. 22, 1983, as amended at 68 FR 70965, Dec. 19, 2003]

§ 60.506 Reconstruction.

For purposes of this subpart:

- (a) The cost of the following frequently replaced components of the affected facility shall not be considered in calculating either the “fixed capital cost of the new components” or the “fixed capital costs that would be required to construct a comparable entirely new facility” under §60.15: pump seals, loading arm gaskets and swivels, coupler gaskets, overfill sensor couplers and cables, flexible vapor hoses, and grounding cables and connectors.
- (b) Under §60.15, the “fixed capital cost of the new components” includes the fixed capital cost of all depreciable components (except components specified in §60.506(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following December 17, 1980. For purposes of this paragraph, “commenced” means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.