

§ 153.303 Applicability.

The provisions of this subpart apply to any owner or operator of a vessel or onshore or offshore facility from which a discharge of oil into coastal waters occurs who acts to remove or arranges for the removal of such discharges.

§ 153.305 Methods and procedures for the removal of discharged oil.

Each person who removes or arranges for the removal of a discharge of oil from coastal waters shall:

(a) Use to the maximum extent possible mechanical methods and sorbents that:

- (1) Most effectively expedite removal of the discharged oil; and
- (2) Minimize secondary pollution from the removal operations;

NOTE: The Federal OSC is authorized by the provisions of the National Contingency Plan to require or deny the use of specific mechanical methods and sorbents. Sorbent selection considerations of the OSC include hydrographic and meteorological conditions, characteristics of the sorbent, and availability of a mechanical method for containment and recovery.

(b) Control the source of discharge, prevent further discharges, and halt or slow the spread of the discharge by mechanical methods or sorbents or both to the maximum extent possible;

(c) Recover the discharged oil from the water or adjoining shorelines by mechanical or manual methods or both to the maximum extent possible;

(d) Use chemical agents only in accordance with the provisions of Subpart H of the National Contingency Plan and with the prior approval of the Federal OSC; and

(e) Dispose of recovered oil and oil contaminated materials in accordance with applicable State and local government procedures.

[CGD 73-185, 41 FR 12630, Mar. 25, 1976, as amended by CGD 84-067, 51 FR 17966, May 16, 1986]

§ 153.307 Penalties.

Any person who fails or refuses to comply with the provisions of this part, or to comply with an order issued by the Federal On-Scene Coordinator under 33 U.S.C. § 1321(c) or (e)(1)(B), is liable for a civil penalty per day of violation or an amount equal to three

times the costs incurred by the Oil Spill Liability Trust Fund as a result of such failure.

[USCG-1998-3799, 63 FR 35531, June 30, 1998]

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AUTHORITY: 33 U.S.C. 1321(j)(1)(C), (j)(5), (j)(6), and (m)(2); 46 U.S.C. 70011, 70034; sec. 2, E.O. 12777, 56 FR 54757; Department of Homeland Security Delegation No. 00170.1, Revision No. 01.2. Subpart F is also issued under 33 U.S.C. 2735. Vapor control recovery provisions of Subpart P are also issued under 42 U.S.C. 7511b(f)(2).

EDITORIAL NOTE: Nomenclature changes to part 154 appear by USCG-2025-0186, 90 FR 12238, Mar. 17, 2025.

Subpart A—General

§ 154.100 Applicability.

(a) This part applies to each facility that is capable of transferring oil or hazardous materials, in bulk, to or from a vessel, where the vessel has a total capacity, from a combination of all bulk products carried, of 39.75 cubic meters (250 barrels) or more. This part does not apply to the facility when it is in a caretaker status. This part does not apply to any offshore facility operating under the jurisdiction of the Secretary of the Department of Interior.

(b) Upon written notice to the facility operator, the COTP may apply, as necessary for the safety of the facility, its personnel, or the public, all or portions of § 154.735 to each facility that is capable of transferring oil or hazardous material, in bulk, only to or from a vessel with a capacity of less than 250 barrels. If the facility is in caretaker status, the COTP may not apply the provisions of § 154.735 to the facility if its storage tanks and piping are gas free.

(c) Upon a determination by the COTP under § 154.1016 that an MTR facility, as defined in subpart F, could reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters, adjoining shorelines, or exclusive economic zone, subpart F of this part is applicable to the facility.

(d) The following sections of this part apply to mobile facilities:

- (1) Section 154.105 Definitions.
- (2) Section 154.107 Alternatives.
- (3) Section 154.108 Exemptions.
- (4) Section 154.110 Letter of Intent.
- (5) Section 154.120 Facility examinations.
- (6) Section 154.300 Operations Manual: General.
- (7) Section 154.310 Operations Manual: Contents. Paragraphs (a)(2), (a)(3), (a)(5) through (a)(7), (a)(9), (a)(12), (a)(14), (a)(16), (a)(17)(ii) through (a)(17)(iv), (a)(18), (a)(20) through (23), (c) and (d).
- (8) Section 154.320 Operations Manual: Amendment.
- (9) Section 154.325 Operations Manual: Procedures for examination.

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(10) Section 154.500 Hose assemblies. Paragraphs (a), (b), (c), (d)(1) through (3) and (e)(1) through (3).

(11) Section 154.520 Closure devices.

(12) Section 154.530 Small discharge containment. Paragraphs (a)(1) through (3) and (d).

(13) Section 154.545 Discharge containment equipment.

(14) Section 154.550 Emergency shut-down.

(15) Section 154.560 Communications.

(16) Section 154.570 Lighting. Paragraphs (c) and (d).

(17) Section 154.700 General.

(18) Section 154.710 Persons in charge: Designation and qualification. Paragraphs (a) through (c), (d)(1) through (3), (d)(7) and (e).

(19) Section 154.730 Persons in charge: Evidence of designation.

(20) Section 154.735 Safety requirements. Paragraphs (d), (f), (g), (j)(1) through (2), (k)(1) through (2), (m), (o) through (q), (r)(1) through (3), (s) and (v).

(21) Section 154.740 Records. Paragraphs (a) through (f) and (j).

(22) Section 154.750 Compliance with Operations Manual.

[CGD 86-034, 55 FR 36252, Sept. 4, 1990, as amended by CGD 91-036, 58 FR 7352, Feb. 5, 1993; CGD 93-056, 61 FR 41457, Aug. 8, 1996]

§ 154.105 Definitions.

As used in this part:

Barrel means a quantity of liquid equal to 42 U.S. gallons.

Boundary Line means any of the lines described in 46 CFR part 7.

Captain of the Port (COTP) means the U.S. Coast Guard officer commanding a Captain of the Port Zone described in part 3 of this chapter, or that person's authorized representative.

Caretaker status denotes a facility where all piping, hoses, loading arms, storage tanks, and related equipment in the marine transfer area are completely free of oil or hazardous materials, where these components have been certified as being gas free, where piping, hoses, and loading arms terminating near any body of water have been blanked, and where the facility operator has notified the COTP that the facility will be in caretaker status.

Commandant means the Commandant of the Coast Guard or an authorized representative.

Contiguous Zone means the entire zone established by the United States under Article 24 of the Convention on the Territorial Sea and the Contiguous Zone, but not extending beyond 12 miles from the baseline from which the breadth of the territorial sea is measured.

District Commander means the officer of the Coast Guard designated by the Commandant to command a Coast Guard District, as described in part 3 of this chapter or an authorized representative.

Facility means either an onshore or offshore facility, except for an offshore facility operating under the jurisdiction of the Secretary of the Department of Interior, and includes, but is not limited to, structure, equipment, and appurtenances thereto, used or capable of being used to transfer oil or hazardous materials to or from a vessel or public vessel. Also included are facilities that tank clean or strip and any floating structure that is used to support an integral part of the facility's operation. A facility includes federal, state, municipal, and private facilities.

Facility operator means the person who owns, operates, or is responsible for the operation of the facility.

Hazardous material means a liquid material or substance, other than oil or liquefied gases, listed under 46 CFR 153.40 (a), (b), (c), or (e).

Marine transfer area means that part of a waterfront facility handling oil or hazardous materials in bulk between the vessel, or where the vessel moors, and the first manifold or shutoff valve on the pipeline encountered after the pipeline enters the secondary containment required under 40 CFR 112.7 or 49 CFR 195.264 inland of the terminal manifold or loading arm, or, in the absence of secondary containment, to the valve or manifold adjacent to the bulk storage tank, including the entire pier or wharf to which a vessel transferring oil or hazardous materials is moored.

MARPOL 73/78 means the International Convention for the Prevention of Pollution from Ships, 1973 (done at London, November 2, 1973) as modified

by the Protocol of 1978 relating to the International Convention for the Prevention of Pollution from Ships, 1973 (done at London, February 17, 1978).

Mobile facility means any facility that can readily change location, such as a tank truck or tank car, other than a vessel or public vessel.

Monitoring device means any fixed or portable sensing device used to monitor for a discharge of oil or hazardous material onto the water, within or around a facility, and designed to notify operating personnel of a discharge of oil or hazardous material.

Officer in Charge, Marine Inspection (OCMI) means the U.S. Coast Guard officer commanding a Marine Inspection Zone described in part 3 of this chapter, or an authorized representative.

Offshore facility means any facility of any kind located in, on, or under, any of the navigable waters of the United States, and any facility of any kind which is subject to the jurisdiction of the United States and is located in, on, or under any other waters, other than a vessel or a public vessel.

Oil means oil of any kind or in any form, including but not limited to, petroleum, fuel oil, sludge, oil refuse, and oil mixed with wastes other than dredged spoil.

Onshore facility means any facility (including, but not limited to, motor vehicles and rolling stock) of any kind located in, on, or under any land within the United States other than submerged land.

Person in charge means an individual designated as a person in charge of transfer operations under §154.710 (for facilities) or §155.700 (for vessels) of this chapter.

STCW means the International Convention on Standards of Training, Certification, and Watchkeeping for Seafarers, 1978.

Self-propelled tank vessel means a self-propelled tank vessel other than a tankship.

Tank barge means a non-self-propelled tank vessel.

Tankship means a self-propelled tank vessel constructed or adapted primarily to carry oil or hazardous material in bulk in the cargo spaces.

Tank vessel means a vessel that is constructed or adapted to carry, or

that carries, oil or hazardous material in bulk as cargo or cargo residue, and that—

- (a) Is a vessel of the United States;
- (b) Operates on the navigable waters of the United States; or
- (c) Transfers oil or hazardous material in a port or place subject to the jurisdiction of the United States.

Transfer means any movement of oil or hazardous material to, from, or within a vessel by means of pumping, gravitation, or displacement. A transfer is considered to begin when the person in charge on the transferring vessel or facility and the person in charge on the receiving facility or vessel first meet to begin completing the declaration of inspection as required by §156.150 of this chapter. A transfer is considered to be complete when all the connections for the transfer have been uncoupled and secured with blanks or other closure devices and both of the persons in charge have completed the declaration of inspection to include the date and time the transfer was complete.

Vessel operator means a person who owns, operates, or is responsible for the operation of a vessel.

[CGD 75-124, 45 FR 7169, Jan. 31, 1980, as amended by CGD 86-034, 55 FR 36252, Sept. 4, 1990; CGD 79-116, 60 FR 17141, Apr. 4, 1995; CGD 93-056, 61 FR 41458, Aug. 8, 1996; 62 FR 3610, Jan. 24, 1997; CGD 79-116, 62 FR 25125, May 8, 1997]

§ 154.106 Incorporation by reference.

(a) Certain material is incorporated by reference (IBR) 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 Coast Guard must publish a 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 Coast Guard Headquarters. Contact Commandant (CG-ENG), Attn: Office of Design and Engineering Standards, U.S. Coast Guard Stop 7509, 2703 Martin Luther King Jr. Avenue SE., Washington, DC 20593-7509, telephone 202-372-1418. You may also contact 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. Also, it is available from the sources indicated in this section.

(b) American National Standards Institute (ANSI), 25 West 43rd Street, 4th floor, New York, NY 10036.

(1) ANSI B16.5, Steel Pipe Flanges and Flanged Fittings, 1988, IBR approved for §§ 154.500(d), 154.2100(b), 154.2101(d), 154.2202(d), and Appendix A, 7.3 to part 154.

(2) ANSI B16.24, Bronze Pipe Flanges and Flange Fittings Class 150 and 300, 1979, IBR approved for §§ 154.500(d) and 154.2100(b).

(3) ANSI B31.3, Chemical Plant and Petroleum Refinery Piping, 1987 (including B31.3a-1988, B31.3b-1988, and B31.3c-1989 addenda), IBR approved for §§ 154.510(a) and 154.2100(b).

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

(1) API Standard 2000, Venting Atmospheric and Low-Pressure Storage Tanks (Non-refrigerated and Refrigerated), Third Edition, January 1982 (reaffirmed December 1987) (“API 2000”), IBR approved for §§ 154.2103(j) and 154.2203(e), (k), and (l).

(2) API Recommended Practice 550, Manual on Installation of Refinery Instruments and Control Systems, Part II—Process Stream Analyzers, Section 1—Oxygen Analyzers, Fourth Edition, February 1985 (“API 550”), IBR approved for § 154.2107(f).

(d) American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016.

(1) ASME B16.34 - 2004, Valves—Flanged, Threaded, and Welding End, issued September 2, 2005, IBR approved for § 154.2100(b).

(2) [Reserved]

(e) ASTM International (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959.

(1) ASTM F631-93, Standard Guide for Collecting Skimmer Performance Data in Controlled Environments (“ASTM F631”), IBR approved for Appendix C, 6.3 to part 154.

(2) ASTM F715-95, Standard Test Methods for Coated Fabrics Used for

Oil Spill Control and Storage (“ASTM F715”), IBR approved for Appendix C, 2.3.1 to part 154.

(3) ASTM F722-82 (Reapproved 2008), Standard Specification for Welded Joints for Shipboard Piping Systems (“ASTM F722”), approved November 1, 2008, IBR approved for Appendix A, 8.4, 8.6 to part 154.

(4) ASTM F1122-87 (Reapproved 1992), Standard Specification for Quick Disconnect Couplings (“ASTM F1122”), IBR approved for § 154.500(d).

(5) ASTM F1155-98, Standard Practice for Selection and Application of Piping System Materials (“ASTM F1155”), IBR approved for Appendix A, 7.1, 8.4 to part 154.

(6) ASTM F1273-91 (Reapproved 2007) Standard Specification for Tank Vent Flame Arresters (“ASTM F1273”), approved December 1, 2007, IBR approved for §§ 154.2001 and 154.2105(j).

(f) International Electrotechnical Commission (IEC), Bureau Central de la Commission Electrotechnique Internationale, 3, rue de Varembé, P.O. Box 131, CH-1211 Geneva 20, Switzerland.

(1) IEC 60309-1 Plugs, Socket-Outlets and Couplers for Industrial Purposes—Part 1: General Requirements, Edition 4.2 2012-06, IBR approved for § 154.2102(b).

(2) IEC 60309-2 Plugs, Socket-Outlets and Couplers for Industrial Purposes—Part 2: Dimensional Interchangeability Requirements for Pin and Contact-tube Accessories, Edition 4.2 2012-05, IBR approved for § 154.2102(b).

(g) National Electrical Manufacturers Association (NEMA), 1300 North 17th Street, Suite 1752, Rosslyn, VA 22209.

(1) ANSI NEMA WD-6—Wiring Devices, Dimensional Requirements, 1988 (“NEMA WD-6”), IBR approved for § 154.2102(a).

(2) [Reserved]

(h) National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, MA 02169-7471.

(1) NFPA 51B, Standard for Fire Prevention in Use of Cutting and Welding Processes, 1994, IBR approved for § 154.735(l).

(2) NFPA 70, National Electrical Code, 1987 (“NFPA 70 (1987)”), IBR approved for § 154.735(q).

(3) NFPA 70, National Electrical Code, 2011 (“NFPA 70 (2011)”), IBR approved for §§ 154.2100(c) and 154.2102(a).

(i) Oil Companies International Marine Forum (OCIMF), 29 Queen Anne’s Gate, London, SW1H 9BU, England.

(1) International Safety Guide for Oil Tankers and Terminals, Fifth Ed., 2006 (“ISGOTT”), IBR approved for §§ 154.735(s), 154.2101(g), and 154.2203(m).

(2) [Reserved]

(j) Underwriters Laboratories, Inc. (UL), 333 Pfingsten Road, Northbrook, IL 60062.

(1) UL 525 Standard for Flame Arresters, 8th Edition, May 9, 2008, IBR approved for §§ 154.2001 and 154.2105(j).

(2) [Reserved]

[USCG–1999–5150, 78 FR 42616, July 16, 2013, as amended by USCG–2014–0410, 79 FR 38436, July 7, 2014]

§ 154.107 Alternatives.

(a) The COTP may consider and approve alternative procedures, methods, or equipment standards to be used by a facility operator in lieu of any requirement in this part if:

(1) Compliance with the requirement is economically or physically impractical;

(2) The alternative provides an equivalent level of safety and protection from pollution by oil or hazardous material, which is documented in the request; and

(3) The facility operator submits a written request for the alternative.

(b) The COTP takes final approval or disapproval action on the request, submitted in accordance with paragraph (a) of this section, in writing within 30 days of receipt of the request.

[CGD 75–124, 45 FR 7169, Jan. 31, 1980, as amended by CGD 86–034, 55 FR 36252, Sept. 4, 1990; CGD 93–056, 61 FR 41458, Aug. 8, 1996]

§ 154.108 Exemptions.

(a) The Assistant Commandant for Marine Safety, Security and Environmental Protection, acting for the Commandant, grants an exemption or partial exemption from compliance with any requirement in this part if:

(1) A facility operator submits an application for the exemption via the COTP; and

(2) It is determined, from the application, that:

(i) Compliance with the requirement is economically or physically impractical;

(ii) No alternative procedures, methods, or equipment standards exist that would provide an equivalent level of safety and protection from pollution by oil or hazardous material; and

(iii) The likelihood of oil or hazardous material being discharged is not substantially increased as a result of the exemption.

(b) If requested, the applicant must submit any appropriate information, including an environmental and economic assessment of the effects of and reasons for the exemption, and proposed procedures, methods or equipment standards.

(c) The exemption may specify the procedures, methods, or equipment standards that will apply.

(d) An exemption is granted or denied in writing. The decision of the Assistant Commandant for Marine Safety, Security and Environmental Protection is a final agency action.

[CGD 75–124, 45 FR 7169, Jan. 31, 1980, as amended by CGD 88–052, 53 FR 25122, July 1, 1988; CGD 86–034, 55 FR 36252, Sept. 4, 1990; 55 FR 49997, Dec. 4, 1990; CGD 96–026, 61 FR 33666, June 28, 1996; CGD 93–056, 61 FR 41458, Aug. 8, 1996; CGD 97–023, 62 FR 33364, June 19, 1997; USCG–2002–12471, 67 FR 41333, June 18, 2002]

§ 154.110 Letter of intent.

(a) The facility operator of any facility to which this part applies must submit a letter of intent to operate a facility or to conduct mobile facility operations to the COTP not less than 60 days before the intended operations unless a shorter period is allowed by the COTP. Previously submitted letters of intent need not be resubmitted.

(b) The letter of intent required by paragraph (a) of this section may be in any form but must contain:

(1) The names, addresses, and telephone numbers of the facility operator and the facility owner;

(2) The name, address, and telephone number of the facility or, in the case of a mobile facility, the dispatching office; and

(3) Except for a mobile facility, the geographical location of the facility in relation to the associated body of navigable waters.

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(c) The facility operator of any facility for which a letter of intent has been submitted, shall within five (5) days advise the COTP in writing of any changes of information and shall cancel, in writing, the letter for any facility at which transfer operations are no longer conducted.

[CGD 75-124, 45 FR 7169, Jan. 31, 1980, as amended by CGD 86-034, 55 FR 36252, Sept. 4, 1990; CGD 93-056, 61 FR 41458, Aug. 8, 1996]

§ 154.120 Facility examinations.

(a) The facility operator shall allow the Coast Guard, at any time, to make any examination and shall perform, upon request, any test to determine compliance with this part and part 156, as applicable. The facility operator shall conduct all required testing of facility equipment in a manner acceptable to the Coast Guard.

(b) The COTP shall provide the facility operator with a written report of the results of the examination for the record required by §154.740(e) and shall list the deficiencies in the report when the facility is not in compliance with the requirements in this part and part 156 of this chapter.

[CGD 75-124, 45 FR 7169, Jan. 31, 1980]

Subpart B—Operations Manual

§ 154.300 Operations manual: General.

(a) The facility operator of each facility to which this part applies must submit to the COTP of the zone(s) in which the facility operates, with the letter of intent, an Operations Manual in printed or electronic format that:

(1) Describes how the applicant meets the operating rules and equipment requirements prescribed by this part and part 156 of this chapter;

(2) Describes the responsibilities of personnel under this part and part 156 of this chapter in conducting transfer operations; and

(3) Includes translations into a language or languages understood by all designated persons in charge of transfer operations employed by the facility.

(4) After September 10, 2021, includes a date, revision date, or other revision-specific identifying information.

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(b) The facility operator must maintain the operations manual so that it is:

(1) Current; and

(2) Readily available for examination by the COTP.

(c) The COTP must examine the Operations Manual when submitted, after any substantial amendment, and as otherwise required by the COTP.

(d) In determining whether the manual meets the requirements of this part and part 156 of this chapter, the COTP will consider the products transferred, and the size, complexity, and capability of the facility.

(e) If the manual meets the requirements of this part and part 156 of this chapter, the COTP will provide notice to the facility stating the manual has been examined by the Coast Guard as described in §154.325. The notice will include the date, revision date of the manual, or other revision-specific identifying information.

(f) The facility operator must ensure printed or electronic copies of the most recently examined Operations Manual, including any translations required by paragraph (a)(3) of this section, are readily available for each facility person in charge while conducting a transfer operation. Electronic devices used to display the manual must comply with applicable electrical safety standards in this part;

NOTE: The facility operator may request that the contents of the operations manual or portions thereof be considered commercial or financial information that is privileged or confidential. Under the Freedom of Information Act, the Coast Guard would withhold any part of the contents of the operations manual from public disclosure upon determining that it is commercial or financial information that is privileged or confidential.

[CGD 75-124, 45 FR 7169, Jan. 31, 1980, as amended by CGD 86-034, 55 FR 36253, Sept. 4, 1990; CGD 93-056, 61 FR 41458, Aug. 8, 1996; USCG-2020-0315, 86 FR 43940, Aug. 11, 2021]

§ 154.310 Operations manual: Contents.

(a) Each operations manual required by §154.300 must contain:

(1) The geographic location of the facility;

(2) A physical description of the facility including a plan and/or plans, maps, drawings, aerial photographs or diagrams, showing the boundaries of the

facility subject to Coast Guard jurisdiction, mooring areas, transfer locations, control stations, wharfs, the extent and scope of the piping subject to the tests required by §156.170(c)(4) of this chapter, and the locations of safety equipment. For mobile facilities, a physical description of the facility;

(3) The hours of operation of the facility;

(4) The sizes, types, and number of vessels that the facility can transfer oil or hazardous material to or from simultaneously;

(5) For each product transferred at the facility:

(i) Generic or chemical name; and

(ii) The following cargo information:

(a) The name of the cargo as listed under appendix II of annex II of MARPOL 73/78, Table 30.25-1 of 46 CFR 30.25-1, Table 151.05 of 46 CFR 151.05-1, or Table 1 of 46 CFR part 153.

(b) A description of the appearance of the cargo;

(c) A description of the odor of the cargo;

(d) The hazards involved in handling the cargo;

(e) Instructions for safe handling of the cargo;

(f) The procedures to be followed if the cargo spills or leaks, or if a person is exposed to the cargo; and

(g) A list of fire fighting procedures and extinguishing agents effective with fires involving the cargo.

(6) The minimum number of persons on duty during transfer operations and their duties;

(7) The name and telephone number of the qualified individual identified under §154.1026 of this part and the title and/or position and telephone number of the Coast Guard, State, local, and other personnel who may be called by the employees of the facility in an emergency;

(8) The duties of watchmen, required by §155.810 of this chapter and 46 CFR 35.05-15, for unmanned vessels moored at the facility;

(9) A description of each communication system required by this part;

(10) The location and facilities of each personnel shelter, if any;

(11) A description and instructions for the use of drip and discharge collec-

tion and vessel slop reception facilities, if any;

(12) A description and the location of each emergency shutdown system;

(13) Quantity, types, locations, and instructions for use of monitoring devices if required by §154.525;

(14) Quantity, type, location, instructions for use, and time limits for gaining access to the containment equipment required by §154.545;

(15) Quantity, type, location, and instructions for use of fire extinguishing equipment required by §154.735(d) of this part;

(16) The maximum allowable working pressure (MAWP) of each loading arm, transfer pipe system, and hose assembly required to be tested by §156.170 of this chapter, including the maximum relief valve setting (or maximum system pressure when relief valves are not provided) for each transfer system;

(17) Procedures for:

(i) Operating each loading arm including the limitations of each loading arm;

(ii) Transferring oil or hazardous material;

(iii) Completion of pumping; and

(iv) Emergencies;

(18) Procedures for reporting and initial containment of oil or hazardous material discharges;

(19) A brief summary of applicable Federal, state, and local oil or hazardous material pollution laws and regulations;

(20) Procedures for shielding portable lighting authorized by the COTP under §154.570(c); and

(21) A description of the training and qualification program for persons in charge.

(22) Statements explaining that each hazardous materials transfer hose is marked with either the name of each product which may be transferred through the hose or with letters, numbers, symbols, color codes or other system acceptable to the COTP representing all such products and the location in the Operations Manual where a chart or list of symbols utilized is located and a list of the compatible products which may be transferred through the hose can be found for consultation before each transfer; and

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(23) For facilities that conduct tank cleaning or stripping operations, a description of their procedures.

(b)(1) The operations manual must contain a description of the facility's vapor control system (VCS), if the facility—

(i) Collects vapor emitted from vessel cargo tanks for recovery, destruction, or dispersion; or

(ii) Balances or transfers vapor to or from vessel cargo tanks.

(2) The VCS description required by paragraph (b)(1) of this section must include a line diagram or simplified piping and instrumentation diagram (P&ID) of the facility's VCS piping, including the location of each valve, control device, pressure-vacuum relief valve, pressure indicator, flame arrester, and detonation arrester;

(3) The VCS description required by paragraph (b)(1) of this section must describe the design and operation of its—

(i) Vapor line connection;

(ii) Startup and shutdown procedures;

(iii) Steady-state operating procedures;

(iv) Provisions for dealing with pyrophoric sulfide (for facilities which handle inerted vapors of cargoes containing sulfur);

(v) Alarms and shutdown devices; and

(vi) Pre-transfer equipment inspection requirements.

(4) The VCS description required by paragraph (b)(1) of this section must include all test procedures and a checklist for use during the testing of the VCS required by 33 CFR 156.170(g). The test procedures must specify—

(i) All tests required for initial certification under 33 CFR 154.2022(d);

(ii) All components that are to be tested; and

(iii) Procedures for testing each component.

(5) The VCS description required by paragraph (b)(1) of this section must include—

(i) A list of all cargoes the VCS is approved to control; and

(ii) Copies of any Coast Guard letters exempting the VCS from regulatory requirements.

(6) The VCS description required by paragraph (b)(1) of this section must

include detailed operating instructions for a cargo line clearance system as described in 33 CFR 154.2104, if such a system is used by a facility;

(7) The VCS description required by paragraph (b)(1) of this section must include the following for a tank barge cleaning facility:

(i) A physical description of the facility and facility plan showing mooring areas, locations where cleaning operations are conducted, control stations, and locations of safety equipment;

(ii) The sizes, types, and number of tank barges from which the facility can conduct cleaning operations simultaneously; and

(iii) The minimum number of persons required to be on duty during cleaning operations and the duties of each.

(c) The facility operator shall incorporate a copy of each amendment to the operations manual under §154.320 in each copy of the manual with the related existing requirement, or add the amendment at the end of each manual if not related to an existing requirement.

(d) The operations manual must be written in the order specified in paragraph (a) of this section, or contain a cross-referenced index page in that order.

(Approved by the Office of Management and Budget under control number 1625–0093)

[CGD 75–124, 45 FR 7171, Jan. 31, 1980, as amended by CGD 88–102, 55 FR 25428, June 21, 1990; CGD 86–034, 55 FR 36253, Sept. 4, 1990; CGD 92–027, 58 FR 39662, July 26, 1993; CGD 93–056, 61 FR 41459, Aug. 8, 1996; USCG–2006–25150, 71 FR 39209, July 12, 2006; USCG–1999–5150, 78 FR 42617, July 16, 2013]

§154.320 Operations manual: Amendment.

(a) Using the following procedures, the COTP may require the facility operator to amend the operations manual if the COTP finds that the operations manual does not meet the requirements in this subchapter:

(1) The COTP will notify the facility operator in writing of any inadequacies in the Operations Manual. The facility operator may submit information, views, and arguments regarding the inadequacies identified, and proposals for amending the Manual, in print or electronically, within 45 days from the

date of the COTP notice. After considering all relevant material presented, the COTP will notify the facility operator of any amendment required or adopted, or the COTP will rescind the notice. The amendment becomes effective 60 days after the facility operator receives the notice, unless the facility operator petitions the Commandant to review the COTP's notice, in which case its effective date is delayed pending a decision by the Commandant. Petitions to the Commandant must be submitted in writing via the COTP who issued the requirement to amend the Operations Manual.

(2) If the COTP finds that there is a condition requiring immediate action to prevent the discharge or risk of discharge of oil or hazardous material that makes the procedure in paragraph (a)(1) of this section impractical or contrary to the public interest, the COTP may issue an amendment effective on the date the facility operator receives notice of it. In such a case, the COTP will include a brief statement of the reasons for the findings in the notice. The owner or operator may petition the Commandant to review the amendment, but the petition does not delay the amendment.

(b) The facility operator may propose amendments to the operations manual by:

(1) Submitting any proposed amendment and reasons for the amendment to the COTP in printed or electronic format not less than 30 days before the requested effective date of the proposed amendment; or

(2) If an immediate amendment is needed, requesting the COTP to examine the amendment immediately.

(c) The COTP will respond to proposed amendments submitted under paragraph (b) of this section by:

(1) Notifying the facility operator that the amendments have been examined by the Coast Guard; or

(2) Notifying the facility operator of any inadequacies in the operations manual or proposed amendments, with an explanation of why the manual or amendments do not meet the requirements of this subchapter.

(d) Amendments to personnel and telephone number lists required by §154.310(a)(7) of this part do not require

examination by the COTP, but the COTP must be advised of such amendments as they occur.

(e) Amendments may be submitted as page replacements or as an entire manual. When an entire manual is submitted, the facility operator must highlight or otherwise annotate the changes that were made since the last version examined by the Coast Guard. A revision date or other revision-specific identifying information must be included on the page replacements or amended manual.

[CGD 75-124, 45 FR 7171, Jan. 31, 1980, as amended by CGD 86-034, 55 FR 36253, Sept. 4, 1990; CGD 93-056, 61 FR 41459, Aug. 8, 1996; USCG-2020-0315, 86 FR 43940, Aug. 11, 2021]

§ 154.325 Operations manual: Procedures for examination.

(a) Not less than 60 days prior to the first transfer operation, the operator of a new facility must submit, with the letter of intent, an Operations Manual in printed or electronic format to the COTP of the zone(s) in which the facility is located.

(b) After a facility is removed from caretaker status, not less than 30 days prior to the first transfer operation, the operator of that facility must submit an Operations Manual in printed or electronic format to the COTP of the zone in which the facility is located, unless the manual has been previously examined and no changes have been made since the examination.

(c) If the COTP finds that the Operations Manual meets the requirements of this part and part 156 of this chapter, the COTP will provide notice to the facility stating the manual has been examined by the Coast Guard. The notice will include the date, revision date of the manual, or other revision-specific identifying information.

(d) If the COTP finds that the Operations Manual does not meet the requirements of this part or part 156 of this subchapter, the COTP will notify the facility with an explanation of why the manual does not meet the requirements of this subchapter.

(e) No person may use any Operations Manual for transfer operations as required by this chapter unless the Operations Manual has been examined by the COTP.

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(f) The Operations Manual is voided if the facility operator—

(1) Amends the Operations Manual without following the procedures in § 154.320 of this part;

(2) Fails to amend the Operations Manual when required by the COTP; or

(3) Notifies the COTP in writing that the facility will be placed in caretaker status.

[CGD 93–056, 61 FR 41459, Aug. 8, 1996, as amended by USCG–2020–0315, 86 FR 43941, Aug. 11, 2021]

Subpart C—Equipment Requirements

§ 154.500 Hose assemblies.

Each hose assembly used for transferring oil or hazardous material must meet the following requirements:

(a) The minimum design burst pressure for each hose assembly must be at least four times the sum of the pressure of the relief valve setting (or four times the maximum pump pressure when no relief valve is installed) plus the static head pressure of the transfer system, at the point where the hose is installed.

(b) The maximum allowable working pressure (MAWP) for each hose assembly must be more than the sum of the pressure of the relief valve setting (or the maximum pump pressure when no relief valve is installed) plus the static head pressure of the transfer system, at the point where the hose is installed.

(c) Each nonmetallic hose must be usable for oil or hazardous material service.

(d) Each hose assembly must either have—

(1) Full threaded connections;

(2) Flanges that meet ANSI B16.5 or ANSI B16.24 (both incorporated by reference, see 33 CFR 154.106); or

(3) Quick-disconnect couplings that meet ASTM F1122 (incorporated by reference, see 33 CFR 154.106).

(e) Each hose must be marked with one of the following:

(1) The name of each product for which the hose may be used; or

(2) For oil products, the words “OIL SERVICE”; or

(3) For hazardous materials, the words “HAZMAT SERVICE—SEE

LIST” followed immediately by a letter, number or other symbol that corresponds to a list or chart contained in the facility’s operations manual or the vessel’s transfer procedure documents which identifies the products that may be transferred through a hose bearing that symbol.

(f) Each hose also must be marked with the following, except that the information required by paragraphs (f)(2) and (3) of this section need not be marked on the hose if it is recorded in the hose records of the vessel or facility, and the hose is marked to identify it with that information:

(1) Maximum allowable working pressure;

(2) Date of manufacture; and

(3) Date of the latest test required by 33 CFR 156.170.

(g) The hose burst pressure and the pressure used for the test required by 33 CFR 156.170 must not be marked on the hose and must be recorded elsewhere at the facility as described in paragraph (f) of this section.

(h) Each hose used to transfer fuel to a vessel that has a fill pipe for which containment cannot practically be provided must be equipped with an automatic back pressure shutoff nozzle.

[USCG–1999–5150, 78 FR 42617, July 16, 2013]

§ 154.510 Loading arms.

(a) Each mechanical loading arm used for transferring oil or hazardous material and placed into service after June 30, 1973, must meet the design, fabrication, material, inspection, and testing requirements in ANSI B31.3 (incorporated by reference; see § 154.106).

(b) The manufacturer’s certification that the standard in paragraph (a) of this section has been met must be permanently marked on the loading arm or recorded elsewhere at the facility with the loading arm marked to identify it with that information.

(c) Each mechanical loading arm used for transferring oil or hazardous material must have a means of being drained or closed before being disconnected after transfer operations are completed.

[CGD 75–124, 45 FR 7172, Jan. 31, 1980, as amended by CGD 86–034, 55 FR 36253, Sept. 4, 1990; USCG–2001–8661, 74 FR 45022, Aug. 31, 2009]

§ 154.520 Closure devices.

(a) Except as provided in paragraph (b) of this section, each facility to which this part applies must have enough butterfly valves, wafer-type resilient seated valves, blank flanges, or other means acceptable to the COTP to blank off the ends of each hose or loading arm that is not connected for the transfer of oil or hazardous material. Such hoses and/or loading arms must be blanked off during the transfer of oil or hazardous material. A suitable material in the joints and couplings shall be installed on each end of the hose assembly or loading arm not being used for transfer to ensure a leak-free seal.

(b) A new, unused hose, and a hose that has been cleaned and is gas free, is exempt from the requirements of paragraph (a) of this section.

[CGD 93-056, 61 FR 41459, Aug. 8, 1996]

§ 154.525 Monitoring devices.

The COTP may require the facility to install monitoring devices if the installation of monitoring devices at the facility would significantly limit the size of a discharge of oil or hazardous material and either:

(a) The environmental sensitivity of the area requires added protection;

(b) The products transferred at the facility pose a significant threat to the environment; or

(c) The size or complexity of the transfer operation poses a significant potential for a discharge of oil or hazardous material.

[CGD 75-124, 45 FR 7172, Jan. 31, 1980, as amended by CGD 86-034, 55 FR 36253, Sept. 4, 1990]

§ 154.530 Small discharge containment.

(a) Except as provided in paragraphs (c), (d), and (e) of this section, each facility to which this part applies must have fixed catchments, curbing, or other fixed means to contain oil or hazardous material discharged in at least—

(1) Each hose handling and loading arm area (that area on the facility that is within the area traversed by the free end of the hose or loading arm when moved from its normal stowed or idle position into a position for connection);

(2) Each hose connection manifold area; and

(3) Under each hose connection that will be coupled or uncoupled as part of the transfer operation during coupling, uncoupling, and transfer.

(b) The discharge containment means required by paragraph (a) of this section must have a capacity of at least:

(1) Two barrels if it serves one or more hoses of 6-inch inside diameter or smaller, or loading arms of 6-inch nominal pipe size diameter or smaller;

(2) Three barrels if it serves one or more hoses with an inside diameter of more than 6-inches, but less than 12 inches, or loading arms with a nominal pipe size diameter of more than 6 inches, but less than 12 inches; or

(3) Four barrels if it serves one or more hoses of 12-inch inside diameter or larger, or loading arms of 12-inch nominal pipe size diameter or larger.

(c) The facility may use portable means of not less than ½ barrel capacity each to meet the requirements of paragraph (a) of this section for part or all of the facility if the COTP finds that fixed means to contain oil or hazardous material discharges are not feasible.

(d) A mobile facility may have portable means of not less than five gallons capacity to meet the requirements of paragraph (a) of this section.

(e) Fixed or portable containment may be used to meet the requirements of paragraph (a)(3) of this section.

[CGD 75-124, 45 FR 7172, Jan. 31, 1980, as amended by CGD 86-034, 55 FR 36253, Sept. 4, 1990; CGD 93-056, 61 FR 41460, Aug. 8, 1996]

§ 154.540 Discharge removal.

Each facility to which this part applies must have a means to safely remove discharged oil or hazardous material, within one hour of completion of the transfer, from the containment required by §154.530 of this part without discharging the oil or hazardous material into the water.

[CGD 93-056, 61 FR 41460, Aug. 8, 1996]

§ 154.545 Discharge containment equipment.

(a) Each facility must have ready access to enough containment material and equipment to contain any oil or

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hazardous material discharged on the water from operations at that facility.

(b) For the purpose of this section, “access” may be by direct ownership, joint ownership, cooperative venture, or contractual agreement.

(c) Each facility must establish time limits, subject to approval by the COTP, for deployment of the containment material and equipment required by paragraph (a) of this section considering:

- (1) Oil or hazardous material handling rates;
- (2) Oil or hazardous material capacity susceptible to being spilled;
- (3) Frequency of facility operations;
- (4) Tidal and current conditions;
- (5) Facility age and configuration; and
- (6) Past record of discharges.

(d) The COTP may require a facility to surround each vessel conducting an oil or hazardous material transfer operation with containment material before commencing a transfer operation if—

- (1) The environmental sensitivity of the area requires the added protection;
- (2) The products transferred at the facility pose a significant threat to the environment;
- (3) The past record of discharges at the facility is poor; or
- (4) The size or complexity of the transfer operation poses a significant potential for a discharge of oil or hazardous material; and
- (5) The use of vessel containment provides the only practical means to reduce the extent of environmental damage.

(e) Equipment and procedures maintained to satisfy the provisions of this chapter may be utilized in the planning requirements of subpart F and subpart H of this part.

[CGD 75-124, 45 FR 7172, Jan. 31, 1980, as amended by CGD 86-034, 55 FR 36253, Sept. 4, 1990; CGD 93-056, 61 FR 41460, Aug. 8, 1996; USCG-1999-5149, 65 FR 40825, June 30, 2000]

§ 154.550 Emergency shutdown.

(a) The facility must have an emergency means to enable the person in charge of the transfer on board the vessel, at that person’s usual operating station, to stop the flow of oil or haz-

ardous material from the facility to the vessel. The means must be—

- (1) An electrical, pneumatic, or mechanical linkage to the facility; or
- (2) An electronic voice communications system continuously operated by a person on the facility who can stop the flow of oil or hazardous material immediately.

(b) The point in the transfer system at which the emergency means stops the flow of oil or hazardous material on the facility must be located near the dock manifold connection to minimize the loss of oil or hazardous material in the event of the rupture or failure of the hose, loading arm, or manifold valve.

(c) For oil transfers, the means used to stop the flow under paragraph (a) of this section must stop that flow within—

- (1) 60 seconds on any facility or portion of a facility that first transferred oil on or before November 1, 1980; and
- (2) 30 seconds on any facility that first transfers oil after November 1, 1980.

(d) For hazardous material transfers, the means used to stop the flow under paragraph (a) of this section must stop that flow within—

- (1) 60 seconds on any facility or portion of a facility that first transferred hazardous material before October 4, 1990; and
- (2) 30 seconds on any facility that first transfers hazardous material on or after October 4, 1990.

[CGD 86-034, 55 FR 36253, Sept. 4, 1990]

§ 154.560 Communications.

(a) Each facility must have a means that enables continuous two-way voice communication between the person in charge of the vessel transfer operation and the person in charge of the facility transfer operation.

(b) Each facility must have a means, which may be the communications system itself, that enables a person on board a vessel or on the facility to effectively indicate the desire to use the means of communication required by paragraph (a) of this section.

(c) The means required by paragraph (a) of this section must be usable and effective in all phases of the transfer

operation and all conditions of weather at the facility.

(d) A facility may use the system in §154.550(a)(2) to meet the requirement of paragraph (a) of this section.

(e) Portable radio devices used to comply with paragraph (a) of this section during the transfer of flammable or combustible liquids must be marked as intrinsically safe by the manufacturer of the device and certified as intrinsically safe by a national testing laboratory or other certification organization approved by the Commandant as defined in 46 CFR 111.105-11. As an alternative to the marking requirement, facility operators may maintain documentation at the facility certifying that the portable radio devices in use at the facility are in compliance with this section.

[CGD 75-124, 45 FR 7172, Jan. 31, 1980; 45 FR 43705, June 30, 1980, as amended by CGD 93-056, 61 FR 41460, Aug. 8, 1996]

§ 154.570 Lighting.

(a) Except as provided in paragraph (c) of this section, for operations between sunset and sunrise, a facility must have fixed lighting that adequately illuminates:

- (1) Each transfer connection point on the facility;
- (2) Each transfer connection point in use on any barge moored at the facility to or from which oil or hazardous material is being transferred;
- (3) Each transfer operations work area on the facility; and
- (4) Each transfer operation work area on any barge moored at the facility to or from which oil or hazardous material is being transferred.

(b) Where the illumination is apparently inadequate, the COTP may require verification by instrument of the levels of illumination. On a horizontal plane 3 feet above the barge deck or walking surface, illumination must measure at least:

- (1) 5.0 foot candles at transfer connection points; and
- (2) 1.0 foot candle in transfer operations work areas.

(c) For small or remote facilities, the COTP may authorize operations with an adequate level of illumination provided by the vessel or by portable means.

(d) Lighting must be located or shielded so as not to mislead or otherwise interfere with navigation on the adjacent waterways.

[CGD 75-124, 45 FR 7172, Jan. 31, 1980, as amended by CGD 86-034, 55 FR 36253, Sept. 4, 1990]

Subpart D—Facility Operations

§ 154.700 General.

No person may operate a facility unless the equipment, personnel, and operating procedures of that facility meet the requirements of this part.

[CGD 75-124, 45 FR 7173, Jan. 31, 1980]

§ 154.710 Persons in charge: Designation and qualification.

No person may serve, and the facility operator may not use the services of a person, as person in charge of facility transfer operations unless:

(a) The facility operator has designated that person as a person in charge;

(b) The person has had at least 48 hours of experience in transfer operations at a facility in operations to which this part applies. The person also has enough experience at the facility for which qualification is desired to enable the facility operator to determine that the person's experience is adequate;

(c) The person has completed a training and qualification program established by the facility operator and described in the Operations Manual in accordance with §154.310(a)(21), that provides the person with the knowledge and training necessary to properly operate the transfer equipment at the facility, perform the duties described in paragraph (d) of this section, follow the procedures required by this part, and fulfill the duties required of a person in charge during an emergency, except that the COTP may approve alternative experience and training requirements for new facilities; and

(d) The facility operator must certify that each person in charge has the knowledge of, and skills necessary to—

- (1) The hazards of each product to be transferred;
- (2) The rules in this part and in part 156 of this chapter;

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- (3) The facility operating procedures as described in the operations manual;
- (4) Vessel transfer systems, in general;
- (5) Vessel transfer control systems, in general;
- (6) Each facility transfer control system to be used;
- (7) Follow local discharge reporting procedures; and
- (8) Carry out the facility's response plan for discharge reporting and containment.

(e) Training conducted to comply with the hazard communication programs required by the Occupational Safety and Health Administration (OSHA) of the Department of Labor (DOL) (29 CFR 1910.1200) or the Environmental Protection Agency (EPA) (40 CFR 311.1), or to meet the requirements of subpart F of this part may be used to satisfy the requirements in paragraphs (c) and (d) of this section, as long as the training addresses the requirements in paragraphs (c) and (d) of this section.

(Sec. 311(j)(1)(C) of the Federal Water Pollution Control Act (86 Stat. 816, 868); 33 U.S.C. 1161(j)(1)(C); E.O. 11548, 3 CFR, 1966-1970 Comp., p. 949; 49 CFR 1.46(m))

[CGD 71-160R, 37 FR 28253, Dec. 21, 1972, as amended by CGD 86-034, 55 FR 36253, Sept. 4, 1990; CGD 93-056, 61 FR 41460, Aug. 8, 1996]

§ 154.730 Persons in charge: Evidence of designation.

Each person in charge shall carry evidence of his designation as a person in charge when he is engaged in transfer operations unless such evidence is immediately available at the facility.

(Sec. 311(j)(1)(C) of the Federal Water Pollution Control Act (86 Stat. 816, 868); 33 U.S.C. 1161(j)(1)(C); E.O. 11548, 3 CFR, 1966-1970 Comp., p. 949; 49 CFR 1.46(m))

[CGD 71-160R, 37 FR 28253, Dec. 21, 1972]

§ 154.735 Safety requirements.

Each operator of a facility to which this part applies shall ensure that the following safety requirements are met at the facility:

- (a) Access to the facility by fire-fighting personnel, fire trucks, or other emergency personnel is not impeded.
- (b) Materials which are classified as hazardous under 49 CFR parts 170 through 179 are kept only in the quan-

ties needed for the operation or maintenance of the facility and are stored in storage compartments.

(c) Gasoline or other fuel is not stored on a pier, wharf, or other similar structure.

(d) A sufficient number of fire extinguishers approved by an independent laboratory listed in 46 CFR 162.028-5 for fighting small, localized fires are in place throughout the facility and maintained in a ready condition.

(e) The location of each hydrant, standpipe, hose station, fire extinguisher, and fire alarm box is conspicuously marked and readily accessible.

(f) Each piece of protective equipment is ready to operate.

(g) Signs indicating that smoking is prohibited are posted in areas where smoking is not permitted.

(h) Trucks and other motor vehicles are operated or parked only in designated locations.

(i) All rubbish is kept in receptacles.

(j) All equipment with internal combustion engines used on the facility—

(1) Does not constitute a fire hazard; and

(2) Has a fire extinguisher attached that is approved by an independent laboratory listed in 46 CFR 162.028-5, unless such a fire extinguisher is readily accessible nearby on the facility.

(k) Spark arresters are provided on chimneys or appliances which—

(1) Use solid fuel; or

(2) Are located where sparks constitute a hazard to nearby combustible material.

(1) All welding or hot work conducted on or at the facility is the responsibility of the facility operator. The COTP may require that the operator of the facility notify the COTP before any welding or hot work operations are conducted. Any welding or hot work operations conducted on or at the facility must be conducted in accordance with NFPA 51B (incorporated by reference; see §154.106). The facility operator shall ensure that the following additional conditions or criteria are met:

(1) Welding or hot work is prohibited during gas freeing operations, within 30.5 meters (100 feet) of bulk cargo operations involving flammable or combustible materials, within 30.5 meters

(100 feet) of fueling operations, or within 30.5 meters (100 feet) of explosives or 15.25 meters (50 feet) of other hazardous materials.

(2) If the welding or hot work is on the boundary of a compartment (*i.e.*, bulkhead, wall or deck) an additional fire watch shall be stationed in the adjoining compartment.

(3) Personnel on fire watch shall have no other duties except to watch for the presence of fire and to prevent the development of hazardous conditions.

(4) Flammable vapors, liquids or solids must first be completely removed from any container, pipe or transfer line subject to welding or hot work.

(5) Tanks used for storage of flammable or combustible substances must be tested and certified gas free prior to starting hot work.

(6) Proper safety precautions in relation to purging, inserting, or venting shall be followed for hot work on containers;

(7) All local laws and ordinances shall be observed;

(8) In case of fire or other hazard, all cutting, welding or other hot work equipment shall be completely secured.

(m) Heating equipment has sufficient clearance to prevent unsafe heating of nearby combustible material.

(n) Automotive equipment having an internal combustion engine is not refueled on a pier, wharf, or other similar structure.

(o) There are no open fires or open flame lamps.

(p) Electric wiring and equipment is maintained in a safe condition so as to prevent fires.

(q) Electrical wiring and electrical equipment installed after October 4, 1990, meet NFPA 70 (1987) (incorporated by reference, see 33 CFR 154.106).

(r) Electrical equipment, fittings, and devices installed after October 4, 1990, show approval for that use by—

(1) Underwriters Laboratories;

(2) Factory Mutual Research Corporation; or

(3) Canadian Standards Association.

(s) Tank-cleaning or gas-freeing operations conducted by the facility on vessels carrying oil residues or mixtures must be conducted in accordance with sections 11.3 and 11.4 of OCIMF ISGOTT

(incorporated by reference, see 33 CFR 154.106), except that—

(1) Prohibitions in ISGOTT against the use of recirculated wash water do not apply if the wash water is first processed to remove product residues;

(2) The provisions in ISGOTT section 11.3.6.10 that removal of sludge, scale, and sediment do not apply if personnel use breathing apparatuses which protect them from the tank atmosphere; and

(3) Upon the request of the facility owner or operator in accordance with 33 CFR 154.107, the COTP may approve the use of alternate standards to ISGOTT if the COTP determines that the alternative standards provide an equal level of protection to the ISGOTT standards.

(t) Guards are stationed, or equivalent controls acceptable to the COTP are used to detect fires, report emergency conditions, and ensure that access to the marine transfer area is limited to—

(1) Personnel who work at the facility including persons assigned for transfer operations, vessel personnel, and delivery and service personnel in the course of their business;

(2) Coast Guard personnel;

(3) Other Federal, State, or local governmental officials; and

(4) Other persons authorized by the operator.

(u) Smoking shall be prohibited at the facility except that facility owners or operators may authorize smoking in designated areas if—

(1) Smoking areas are designated in accordance with local ordinances and regulations;

(2) Signs are conspicuously posted marking such authorized smoking areas; and

(3) “No Smoking” signs are conspicuously posted elsewhere on the facility.

(v) Warning signs shall be displayed on the facility at each shoreside entry to the dock or berth, without obstruction, at all times for fixed facilities and for mobile facilities during coupling, transfer operation, and uncoupling. The warning signs shall conform

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to 46 CFR 151.45-2(e)(1) or 46 CFR 153.955.

[CGD 86-034, 55 FR 36253, Sept. 4, 1990, as amended by CGD 93-056, 61 FR 41460, Aug. 8, 1996; USCG-2001-8661, 74 FR 45022, Aug. 31, 2009; USCG-1999-5150, 78 FR 42618, July 16, 2013]

§ 154.740 Records.

Each facility operator shall maintain at the facility and make available for examination by the COTP:

(a) A copy of the letter of intent for the facility;

(b) The name of each person designated as a person in charge of transfer operations at the facility and certification that each person in charge has completed the training requirements of § 154.710 of this part;

(c) The date and result of the most recent test or examination of each item tested or examined under § 156.170 of this chapter;

(d) The hose information required by § 154.500 (e) and (g) except that marked on the hose;

(e) The record of all examinations of the facility by the COTP within the last 3 years;

(f) The Declaration of Inspection required by § 156.150(f) of this chapter;

(g) A record of all repairs made within the last three years involving any component of the facility's vapor control system required by subpart P of this part;

(h) A record of all automatic shut downs of the facility's vapor control system within the last 3 years; and

(i) Plans, calculations, and specifications of the facility's vapor control system certified under 33 CFR 154.2020 through 154.2025.

(j) If they are not marked as such, documentation that the portable radio devices in use at the facility under § 154.560 of this part are intrinsically safe.

(Approved by the Office of Management and Budget under control number 1625-0060)

[CGD 75-124, 45 FR 7173, Jan. 31, 1980, as amended by CGD 88-102, 55 FR 25429, June 21, 1990; CGD 86-034, 55 FR 36254, Sept. 4, 1990; CGD 93-056, 61 FR 41461, Aug. 8, 1996; USCG-2006-25150, 71 FR 39209, July 12, 2006; USCG-1999-5150, 78 FR 42618, July 16, 2013]

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§ 154.750 Compliance with operations manual.

The facility operator shall require facility personnel to use the procedures in the operations manual prescribed by § 154.300 for operations under this part.

[CGD 75-124, 45 FR 7174, Jan. 31, 1980]

Subpart E [Reserved]

Subpart F—Response Plans for Oil Facilities

SOURCE: CGD 91-036, 61 FR 7917, Feb. 29, 1996, unless otherwise noted.

§ 154.1010 Purpose.

This subpart establishes oil spill response plan requirements for all marine transportation-related (MTR) facilities (hereafter also referred to as facilities) that could reasonably be expected to cause substantial harm or significant and substantial harm to the environment by discharging oil into or on the navigable waters, adjoining shorelines, or exclusive economic zone. The development of a response plan prepares the facility owner or operator to respond to an oil spill. These requirements specify criteria to be used during the planning process to determine the appropriate response resources. The specific criteria for response resources and their arrival times are not performance standards. The criteria are based on a set of assumptions that may not exist during an actual oil spill incident.

§ 154.1015 Applicability.

(a) This subpart applies to all MTR facilities that because of their location could reasonably be expected to cause at least substantial harm to the environment by discharging oil into or on the navigable waters, adjoining shorelines, or exclusive economic zone.

(b) The following MTR facilities that handle, store, or transport oil, in bulk, could reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines and are classified as substantial harm MTR facilities:

(1) Fixed MTR onshore facilities capable of transferring oil to or from a

vessel with a capacity of 250 barrels or more and deepwater ports;

(2) Mobile MTR facilities used or intended to be used to transfer oil to or from a vessel with a capacity of 250 barrels or more; and

(3) Those MTR facilities specifically designated as substantial harm facilities by the COTP under §154.1016.

(c) The following MTR facilities that handle, store, or transport oil in bulk could not only reasonably be expected to cause substantial harm, but also significant and substantial harm, to the environment by discharging oil into or on the navigable waters, adjoining shorelines, or exclusive economic zone and are classified as significant and substantial harm MTR facilities:

(1) Deepwater ports, and fixed MTR onshore facilities capable of transferring oil to or from a vessel with a capacity of 250 barrels or more except for facilities that are part of a non-transportation-related fixed onshore facility with a storage capacity of less than 42,000 gallons; and

(2) Those MTR facilities specifically designated as significant and substantial harm facilities by the COTP under §154.1016.

(d) An MTR facility owner or operator who believes the facility is improperly classified may request review and reclassification in accordance with §154.1075.

§ 154.1016 Facility classification by COTP.

(a) The COTP may upgrade the classification of:

(1) An MTR facility not specified in §154.1015 (b) or (c) to a facility that could reasonably be expected to cause substantial harm to the environment; or

(2) An MTR facility specified in §154.1015(b) to a facility that could reasonably be expected to cause significant and substantial harm to the environment.

(b) The COTP may downgrade, the classification of:

(1) An MTR facility specified in §154.1015(c) to a facility that could reasonably be expected to cause substantial harm to the environment; or

(2) An MTR facility specified in §154.1015(b) to a facility that could not

reasonably be expected to cause substantial, or significant and substantial harm to the environment.

(3) The COTP will consider downgrading an MTR facility's classification only upon receiving a written request for a downgrade of classification from the facility's owner or operator.

(c) When changing a facility classification the COTP may, as appropriate, consider all relevant factors including, but not limited to: Type and quantity of oils handled in bulk; facility spill history; age of facility; proximity to public and commercial water supply intakes; proximity to navigable waters based on the definition of navigable waters in 33 CFR 2.36; and proximity to fish and wildlife and sensitive environments.

[CGD 91-036, 61 FR 7917, Feb. 29, 1996, as amended by USCG-2008-0179, 73 FR 35014, June 19, 2008]

§ 154.1017 Response plan submission requirements.

(a) The owner or operator of an MTR facility identified only in §154.1015(b), or designated by the COTP as a substantial harm facility, shall prepare and submit to the cognizant COTP a response plan that meets the requirements of §154.1030, §154.1040, §154.1045, or §154.1047, as appropriate. This applies to:

(1) A mobile MTR facility used or intended to be used to transfer oil to or from a vessel with a capacity of 250 barrels or more; and

(2) A fixed MTR facility specifically designated as a substantial harm facility by the COTP under §154.1016.

(b) The owner or operator of an MTR facility identified in §154.1015(c) or designated by the COTP as a significant and substantial harm facility shall prepare and submit for review and approval of the cognizant COTP a response plan that meets the requirements of §154.1030, §154.1035, §154.1045, or §154.1047, as appropriate. This applies to:

(1) A fixed MTR facility capable of transferring oil, in bulk, to or from a vessel with a capacity of 250 barrels or more; and

(2) An MTR facility specifically designated as a significant and substantial

harm facility by the COTP under § 154.1016.

(c) In addition to the requirements in paragraphs (a) and (b) of this section, the response plan for a mobile MTR facility must meet the requirements of § 154.1041 subpart F.

§ 154.1020 Definitions.

Except as otherwise defined in this section, the definition in 33 CFR 154.105 apply to this subpart and subparts H and I.

Adverse weather means the weather conditions that will be considered when identifying response systems and equipment in a response plan for the applicable operating environment. Factors to consider include, but are not limited to, significant wave height as specified in § 154.1045, § 154.1047, § 154.1225, or § 154.1325, as appropriate; ice conditions, temperatures, weather-related visibility, and currents within the COTP zone in which the systems or equipment are intended to function.

Animal fat means a non-petroleum oil, fat, or grease derived from animals, and not specifically identified elsewhere in this part.

Average most probable discharge means a discharge of the lesser of 50 barrels or 1 percent of the volume of the worst case discharge.

Captain of the Port (COTP) Zone means a zone specified in 33 CFR part 3 and, where applicable, the seaward extension of that zone to the outer boundary of the exclusive economic zone (EEZ).

Complex means a facility possessing a combination of marine-transportation related and non-transportation-related components that is subject to the jurisdiction of more than one Federal agency under section 311(j) of the Clean Water Act.

Dispersant-application platform means the vessel or aircraft outfitted with the dispersant-application equipment acting as the delivery system for the dispersant onto the oil spill.

Effective Daily Application Capacity or EDAC means the estimated amount of dispersant that can be applied to a discharge by an application system given the availability of supporting dispersant stockpiles, when operated in accordance with approved standards and

within acceptable environmental conditions.

Estimated Dispersant System Potential Calculator (EDSP) means an internet-accessible application that estimates EDAC for different dispersant response systems. The NSFCC will use EDSP for evaluating OSRO dispersant classification levels.

Exclusive economic zone (EEZ) means the zone contiguous to the territorial sea of the United States extending to a distance up to 200 nautical miles from the baseline from which the breadth of the territorial sea is measured.

Facility that could reasonably be expected to cause significant and substantial harm means any MTR facility (including piping and any structures that are used for the transfer of oil between a vessel and a facility) classified as a “significant and substantial harm” facility under § 154.1015(c) and § 154.1216.

Facility that could reasonably be expected to cause substantial harm means any MTR facility classified as a “substantial harm” facility under § 154.1015(b) and § 154.1216.

Fish and Wildlife and Sensitive Environment means areas that may be identified by either their legal designation or by Area Committees in the applicable Area Contingency Plan (ACP) (for planning) or by members of the Federal On-Scene Coordinator’s spill response structure (during responses). These areas may include: Wetlands, national and state parks, critical habitats for endangered or threatened species, wilderness and natural resource areas, marine sanctuaries and estuarine reserves, conservation areas, preserves, wildlife areas, wildlife refuges, wild and scenic rivers, areas of economic importance, recreational areas, national forests, Federal and state lands that are research areas, heritage program areas, land trust areas, and historical and archaeological sites and parks. These areas may also include unique habitats such as: aquaculture sites and agricultural surface water intakes, bird nesting areas, critical biological resource areas, designated migratory routes, and designated seasonal habitats.

Great Lakes means Lakes Superior, Michigan, Huron, Erie, and Ontario, their connecting and tributary waters,

the Saint Lawrence River as far as Saint Regis, and adjacent port areas.

Gulf Coast means, for the purposes of dispersant-application requirements, the region encompassing the following Captain of the Port Zones:

- (1) Corpus Christi, TX.
- (2) Houston/Galveston, TX.
- (3) Port Arthur, TX.
- (4) Morgan City, LA.
- (5) New Orleans, LA.
- (6) Mobile, AL.
- (7) St. Petersburg, FL.

Higher volume port area means the following ports:

- (1) Boston, MA.
- (2) New York, NY.
- (3) Delaware Bay and River to Philadelphia, PA.
- (4) St. Croix, VI.
- (5) Pascagoula, MS.
- (6) Mississippi River from Southwest Pass, LA. to Baton Rouge, LA.
- (7) Louisiana Offshore Oil Port (LOOP), LA.
- (8) Lake Charles, LA.
- (9) Sabine-Neches River, TX.
- (10) Galveston Bay and Houston Ship Channel, TX.
- (11) Corpus Christi, TX.
- (12) Los Angeles/Long Beach harbor, CA.
- (13) San Francisco Bay, San Pablo Bay, Carquinez Strait, and Suisun Bay to Antioch, CA.
- (14) Straits of Juan De Fuca from Port Angeles, WA, to and including Puget Sound, WA.
- (15) Prince William Sound, AK.

Inland area means the area shoreward of the boundary lines defined in 46 CFR part 7, except in the Gulf of America. In the Gulf of America, it means the area shoreward of the lines of demarcation (COLREG lines) defined in §§ 80.740 through 80.850 of this chapter. The inland area does not include the Great Lakes.

Marine transportation-related facility (MTR facility) means any onshore facility or segment of a complex regulated under section 311(j) of the Federal Water Pollution Control Act (FWPCA) by two or more Federal agencies, including piping and any structure used or intended to be used to transfer oil to or from a vessel, subject to regulation under this part and any deepwater port subject to regulation under part 150 of

this chapter. For a facility or segment of a complex regulated by two or more Federal agencies under section 311(j) of the FWPCA, the MTR portion of the complex extends from the facility oil transfer system's connection with the vessel to the first valve inside the secondary containment surrounding tanks in the non-transportation-related portion of the facility or, in the absence of secondary containment, to the valve or manifold adjacent to the tanks comprising the non-transportation-related portion of the facility, unless another location has otherwise been agreed to by the COTP and the appropriate Federal official.

Maximum extent practicable means the planned capability to respond to a worst case discharge in adverse weather, as contained in a response plan that meets the criteria in this subpart or in a specific plan approved by the cognizant COTP.

Maximum most probable discharge means a discharge of the lesser of 1,200 barrels or 10 percent of the volume of a worst case discharge.

Nearshore area means the area extending seaward 12 miles from the boundary lines defined in 46 CFR part 7, except in the Gulf of America. In the Gulf of America, it means the area extending seaward 12 miles from the line of demarcation (COLREG lines) defined in §§ 80.740–80.850 of this chapter.

Non-persistent or Group I oil means a petroleum-based oil that, at the time of shipment, consists of hydrocarbon fractions—

- (1) At least 50 percent of which by volume, distill at a temperature of 340 degrees C (645 degrees F); and
- (2) At least 95 percent of which by volume, distill at a temperature of 370 degrees C (700 degrees F).

Ocean means the offshore area and nearshore area as defined in this subpart.

Offshore area means the area beyond 12 nautical miles measured from the boundary lines defined in 46 CFR part 7 extending seaward to 50 nautical miles, except in the Gulf of America. In the Gulf of America, it is the area beyond 12 nautical miles of the line of demarcation (COLREG lines) defined in §§ 80.740–80.850 of this chapter extending seaward to 50 nautical miles.

Oil means oil of any kind or in any form, including, but not limited to, petroleum, fuel oil, sludge, oil refuse, oil mixed with wastes other than dredge spoil.

Oil spill removal organization (OSRO) means an entity that provides response resources.

On-Scene Coordinator (OSC) means the definition in the National Oil and Hazardous Substances Pollution Contingency Plan (40 CFR part 300).

Operating area means Rivers and Canals, Inland, Nearshore, Great Lakes, or Offshore geographic location(s) in which a facility is handling, storing, or transporting oil.

Operating environment means Rivers and Canals, Inland, Great Lakes, or Ocean. These terms are used to define the conditions in which response equipment is designed to function.

Operating in compliance with the plan means operating in compliance with the provisions of this subpart including, ensuring the availability of the response resources by contract or other approved means, and conducting the necessary training and drills.

Operational effectiveness monitoring means monitoring concerned primarily with determining whether the dispersant was properly applied and how the dispersant is affecting the oil.

Other non-petroleum oil means a non-petroleum oil of any kind that is not generally an animal fat or vegetable oil.

Persistent oil means a petroleum-based oil that does not meet the distillation criteria for a non-persistent oil. For the purposes of this subpart, persistent oils are further classified based on specific gravity as follows:

- (1) Group II—specific gravity of less than .85.
- (2) Group III—specific gravity equal to or greater than .85 and less than .95.
- (3) Group IV—specific gravity equal to or greater than .95 and less than or equal to 1.0.
- (4) Group V—specific gravity greater than 1.0.

Pre-authorization for dispersant use means an agreement, adopted by a regional response team in coordination with area committees, which authorizes the use of dispersants at the discretion of the Federal On-Scene Coor-

dinator without the further approval of other Federal or State authorities. These pre-authorization areas are generally limited to particular geographic areas within each region.

Primary dispersant staging site means a site designated within a Captain of the Port zone that has been identified as a forward staging area for dispersant application platforms and the loading of dispersant stockpiles. Primary staging sites are typically the planned locations where platforms load or reload dispersants before departing for application at the site of the discharge and may not be the locations where dispersant stockpiles are stored or application platforms are home-based.

Qualified individual and alternate qualified individual means a person located in the United States who meets the requirements of §154.1026.

Response activities means the containment and removal of oil from the land, water, and shorelines, the temporary storage and disposal of recovered oil, or the taking of other actions as necessary to minimize or mitigate damage to the public health or welfare or the environment.

Response resources means the personnel, equipment, supplies, and other capability necessary to perform the response activities identified in a response plan.

Rivers and canals means a body of water confined within the inland area, including the Intracoastal Waterways and other waterways artificially created for navigation, that has a project depth of 12 feet or less.

Specific gravity means the ratio of the mass of a given volume of liquid at 15 °C (60 °F) to the mass of an equal volume of pure water at the same temperature.

Spill management team means the personnel identified to staff the organizational structure identified in a response plan to manage response plan implementation.

Substantial threat of a discharge means any incident or condition involving a facility that may create a risk of discharge of oil. Such incidents include, but are not limited to storage tank or

pipings failures, above ground or underground leaks, fires, explosions, flooding, spills contained within the facility, or other similar occurrences.

Tier means the combination of required response resources and the times within which the resources must arrive on scene.

NOTE: Tiers are applied in three categories:

- (1) Higher Volume Port Areas,
- (2) Great Lakes, and
- (3) All other operating environments, including rivers and canals, inland, nearshore, and offshore areas.

Appendix C, Table 4 of this part, provides specific guidance on calculating response resources. Sections 154.1045(f) and 154.1135, set forth the required times within which the response resources must arrive on-scene.

Vegetable oil means a non-petroleum oil or fat derived from plant seeds, nuts, kernels or fruits, and not specifically identified elsewhere in this part.

Worst case discharge means in the case of an onshore facility and deepwater port, the largest foreseeable discharge in adverse weather conditions meeting the requirements of § 154.1029.

[CGD 91-036, 61 FR 7917, Feb. 29, 1996, as amended by USCG-1999-5149, 65 FR 40825, June 30, 2000; USCG-2001-8661, 74 FR 45023, Aug. 31, 2009; USCG-2018-0874, 84 FR 30880, June 28, 2019]

§ 154.1025 Operating restrictions and interim operating authorization.

(a) The owner or operator of an MTR facility who submitted a response plan prior to May 29, 1996, may elect to comply with any of the provisions of this final rule by revising the appropriate section of the previously submitted plan in accordance with § 154.1065. An owner or operator of an MTR facility who elects to comply with all sections of this final rule must resubmit the plan in accordance with § 154.1060 of this part.

(b) No facility subject to this subpart may handle, store, or transport oil unless it is operating in full compliance with a submitted response plan. No facility categorized under § 154.1015(c) as a significant and substantial harm facility may handle, store, or transport oil unless the submitted response plan has been approved by the COTP. The owner or operator of each new facility to which this subpart applies must submit a response plan meeting the re-

quirements listed in § 154.1017 not less than 60 days prior to handling, storing, or transporting oil. Where applicable, the response plan shall be submitted along with the letter of intent required under § 154.110.

(c) Notwithstanding the requirements of paragraph (b) of this section, a facility categorized under § 154.1015(c) as a significant and substantial harm facility may continue to handle, store, or transport oil for 2 years after the date of submission of a response plan, pending approval of that plan. To continue to handle, store, or transport oil without a plan approved by the COTP, the facility owner or operator shall certify in writing to the COTP that the owner or operator has ensured, by contract or other approved means as described in § 154.1028(a), the availability of the necessary private personnel and equipment to respond, to the maximum extent practicable to a worst case discharge or substantial threat of such a discharge from the facility. Provided that the COTP is satisfied with the certification of response resources provided by the owner or operator of the facility, the COTP will provide written authorization for the facility to handle, store, or transport oil while the submitted response plan is being reviewed. Pending approval of the submitted response plan, deficiencies noted by the COTP must be corrected in accordance with § 154.1070.

(d) A facility may not continue to handle, store, or transport oil if—

(1) The COTP determines that the response resources identified in the facility certification statement or reference response plan do not substantially meet the requirements of this subpart;

(2) The contracts or agreements cited in the facility's certification statement or referenced response plans are no longer valid;

(3) The facility is not operating in compliance with the submitted plan;

(4) The response plan has not been resubmitted or approved within the last 5 years; or

(5) The period of the authorization under paragraph (c) of this section has expired.

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§ 154.1026 Qualified individual and alternate qualified individual.

(a) The response plan must identify a qualified individual and at least one alternate who meet the requirements of this section. The qualified individual or alternate must be available on a 24-hour basis and be able to arrive at the facility in a reasonable time.

(b) The qualified individual and alternate must:

- (1) Be located in the United States;
- (2) Speak fluent English;
- (3) Be familiar with the implementation of the facility response plan; and
- (4) Be trained in the responsibilities of the qualified individual under the response plan.

(c) The owner or operator shall provide each qualified individual and alternate qualified individual identified in the plan with a document designating them as a qualified individual and specifying their full authority to:

- (1) Activate and engage in contracting with oil spill removal organization(s);
- (2) Act as a liaison with the predesignated Federal On-Scene Coordinator (OSC); and
- (3) Obligate funds required to carry out response activities.

(d) The owner or operator of a facility may designate an organization to fulfill the role of the qualified individual and the alternate qualified individual. The organization must then identify a qualified individual and at least one alternate qualified individual who meet the requirements of this section. The facility owner or operator is required to list in the response plan the organization, the person identified as the qualified individual, and the person or person(s) identified as the alternate qualified individual(s).

(e) The qualified individual is not responsible for—

- (1) The adequacy of response plans prepared by the owner or operator; or
- (2) Contracting or obligating funds for response resources beyond the authority contained in their designation from the owner or operator of the facility.

(f) The liability of a qualified individual is considered to be in accordance with the provisions of 33 USC 1321(c)(4).

§ 154.1028 Methods of ensuring the availability of response resources by contract or other approved means.

(a) When required in this subpart, the availability of response resources must be ensured by the following methods:

(1) A written contractual agreement with an oil spill removal organization. The agreement must identify and ensure the availability of specified personnel and equipment required under this subpart within stipulated response times in the specified geographic areas;

(2) Certification by the facility owner or operator that specified personnel and equipment required under this subpart are owned, operated, or under the direct control of the facility owner or operator, and are available within stipulated response times in the specified geographic areas;

(3) Active membership in a local or regional oil spill removal organization that has identified specified personnel and equipment required under this subpart that are available to respond to a discharge within stipulated response times in the specified geographic areas;

(4) A document which—
(i) Identifies the personnel, equipment, and services capable of being provided by the oil spill removal organization within stipulated response times in the specified geographic areas;

(ii) Sets out the parties' acknowledgment that the oil spill removal organization intends to commit the resources in the event of a response;

(iii) Permits the Coast Guard to verify the availability of the identified response resources through tests, inspections, and drills; and

(iv) Is referenced in the response plan; or

(5) The identification of an oil spill removal organization with specified equipment and personnel available within stipulated response times in specified geographic areas. The organization must provide written consent to being identified in the plan.

(b) The contracts and documents required in paragraph (a) of this section must be retained at the facility and must be produced for review upon request by the COTP.

§ 154.1029 Worst case discharge.

(a) The response plan must use the appropriate criteria in this section to develop the worst case discharge.

(b) For the MTR segment of a facility, not less than—

(1) Where applicable, the loss of the entire capacity of all in-line and break out tank(s) needed for the continuous operation of the pipelines used for the purposes of handling or transporting oil, in bulk, to or from a vessel regardless of the presence of secondary containment; plus

(2) The discharge from all piping carrying oil between the marine transfer manifold and the non-transportation-related portion of the facility. The discharge from each pipe is calculated as follows: The maximum time to discover the release from the pipe in hours, plus the maximum time to shut down flow from the pipe in hours (based on historic discharge data or the best estimate in the absence of historic discharge data for the facility) multiplied by the maximum flow rate expressed in barrels per hour (based on the maximum relief valve setting or maximum system pressure when relief valves are not provided) plus the total line drainage volume expressed in barrels for the pipe between the marine manifold and the non-transportation-related portion of the facility; and

(c) For a mobile facility it means the loss of the entire contents of the container in which the oil is stored or transported.

§ 154.1030 General response plan contents.

(a) The plan must be written in English.

(b) A response plan must be divided into the sections listed in this paragraph and formatted in the order specified herein unless noted otherwise. It must also have some easily found marker identifying each section listed below. The following are the sections and subsections of a facility response plan:

- (1) Introduction and plan contents.
- (2) Emergency response action plan:
 - (i) Notification procedures.
 - (ii) Facility's spill mitigation procedures.
 - (iii) Facility's response activities.

(iv) Fish and wildlife and sensitive environments.

(v) Disposal plan.

(3) Training and Exercises:

(i) Training procedures.

(ii) Exercise procedures.

(4) Plan review and update procedures.

(5) Appendices.

(i) Facility-specific information.

(ii) List of contacts.

(iii) Equipment lists and records.

(iv) Communications plan.

(v) Site-specific safety and health plan.

(vi) List of acronyms and definitions.

(vii) A geographic-specific appendix for each zone in which a mobile facility operates.

(c) The required contents for each section and subsection of the plan are contained in §§ 154.1035, 154.1040, and 154.1041, as appropriate.

(d) The sections and subsections of response plans submitted to the COTP must contain at a minimum all the information required in §§ 154.1035, 154.1040, and 154.1041, as appropriate. It may contain other appropriate sections, subsections, or information that are required by other Federal, State, and local agencies.

(e) For initial and subsequent submission, a plan that does not follow the format specified in paragraph (b) of this section must be supplemented with a detailed cross-reference section to identify the location of the applicable sections required by this subpart.

(f) The information contained in a response plan must be consistent with the National Oil and Hazardous Substances Pollution Contingency Plan (NCP) (40 CFR part 300) and the Area Contingency Plan(s) (ACP) covering the area in which the facility operates. Facility owners or operators shall ensure that their response plans are in accordance with the ACP in effect 6 months prior to initial plan submission or the annual plan review required under § 154.1065(a). Facility owners or operators are not required to, but may at their option, conform to an ACP which is less than 6 months old at the time of plan submission.

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§ 154.1035 Specific requirements for facilities that could reasonably be expected to cause significant and substantial harm to the environment.

(a) *Introduction and plan content.* This section of the plan must include facility and plan information as follows:

(1) The facility’s name, street address, city, county, state, ZIP code, facility telephone number, and telefacsimile number, if so equipped. Include mailing address if different from street address.

(2) The facility’s location described in a manner that could aid both a reviewer and a responder in locating the specific facility covered by the plan, such as, river mile or location from a known landmark that would appear on a map or chart.

(3) The name, address, and procedures for contacting the facility’s owner or operator on a 24-hour basis.

(4) A table of contents.

(5) During the period that the submitted plan does not have to conform to the format contained in this subpart, a cross index, if appropriate.

(6) A record of change(s) to record information on plan updates.

(b) *Emergency Response Action Plan.* This section of the plan must be organized in the subsections described in this paragraph:

(1) *Notification procedures.* (i) This subsection must contain a prioritized list identifying the person(s), including name, telephone number, and their role in the plan, to be notified of a discharge or substantial threat of a discharge of oil. The telephone number need not be provided if it is listed separately in the list of contacts required in the plan. This Notification Procedures listing must include—

(A) Facility response personnel, the spill management team, oil spill removal organizations, and the qualified individual(s) and the designated alternate(s); and

(B) Federal, State, or local agencies, as required.

(ii) This subsection must include a form, such as that depicted in Figure 1, which contains information to be provided in the initial and follow-up notifications to Federal, State, and local agencies. The form shall include notification of the National Response Center as required in part 153 of this chapter. Copies of the form also must be placed at the location(s) from which notification may be made. The initial notification form must include space for the information contained in Figure 1. The form must contain a prominent statement that initial notification must not be delayed pending collection of all information.

FIGURE 1—INFORMATION ON DISCHARGE *
[Involved Parties]

(A) Reporting party	(B) Suspected responsible party
Name	Name
Phones () –	Phones () –
Company	Company
Position	Organization Type:
Address	Private citizen
Address	Private enterprise
	Public utility
	Local government
	State government
	Federal government
City	City
State	State
Zip	Zip
* It is not necessary to wait for all information before calling NRC. National Response Center—1-800-424-8802 or direct telephone: 202-267-2675.	
Were materials Discharged (Y/N)?	
Calling for Responsible Party (Y/N)	
Incident Description	
Source and/or Cause of Incident	
Date - - Time:	

Cause
Incident Address/Location Nearest City Distance from City Storage Tank Container Type—Above ground (Y/N) Below ground (Y/N) Unknown
Facility Capacity
Tank Capacity Latitude Degrees Longitude Degrees Mile Post or River Mile
Materials
Discharge Unit of Quantity Measure Discharged Material Quantity in Water
Response Action
Actions Taken to Correct or Mitigate Incident
Impact
Number of Injuries Number of Fatalities Were there Evacuations (Y/N/U)? Number Evacuated Was there any Damage (Y/N/U)? Damage in Dollars
Additional Information
Any information about the Incident not recorded elsewhere in the report
Caller Notifications
USCG EPA State Other

(2) *Facility's spill mitigation procedures.*

(i) This subsection must describe the volume(s) and oil groups that would be involved in the—

(A) Average most probable discharge from the MTR facility;

(B) Maximum most probable discharge from the MTR facility;

(C) Worst case discharge from the MTR facility; and

(D) Where applicable, the worst case discharge from the non-transportation-related facility. This must be the same volume provided in the response plan for the non-transportation-related facility.

(ii) This subsection must contain prioritized procedures for facility personnel to mitigate or prevent any discharge or substantial threat of a discharge of oil resulting from operational activities associated with internal or external facility transfers including specific procedures to shut down affected operations. Facility personnel responsible for performing specified procedures to mitigate or prevent

any discharge or potential discharge shall be identified by job title. A copy of these procedures shall be maintained at the facility operations center. These procedures must address actions to be taken by facility personnel in the event of a discharge, potential discharge, or emergency involving the following equipment and scenarios:

(A) Failure of manifold, mechanical loading arm, other transfer equipment, or hoses, as appropriate;

(B) Tank overfill;

(C) Tank failure;

(D) Piping rupture;

(E) Piping leak, both under pressure and not under pressure, if applicable;

(F) Explosion or fire; and

(G) Equipment failure (e.g. pumping system failure, relief valve failure, or other general equipment relevant to operational activities associated with internal or external facility transfers.)

(iii) This subsection must contain a listing of equipment and the responsibilities of facility personnel to mitigate an average most probable discharge.

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(3) *Facility's response activities.* (i) This subsection must contain a description of the facility personnel's responsibilities to initiate a response and supervise response resources pending the arrival of the qualified individual.

(ii) This subsection must contain a description of the responsibilities and authority of the qualified individual and alternate as required in §154.1026.

(iii) This subsection must describe the organizational structure that will be used to manage the response actions. This structure must include the following functional areas.

- (A) Command and control;
- (B) Public information;
- (C) Safety;
- (D) Liaison with government agencies;
- (E) Spill Operations;
- (F) Planning;
- (G) Logistics support; and
- (H) Finance.

(iv) This subsection of the plan must identify the oil spill removal organizations and the spill management team that will be capable of providing the following resources:

(A) Equipment and supplies to meet the requirements of §§154.1045, 154.1047, or subparts H or I of this part, as appropriate.

(B) Trained personnel necessary to continue operation of the equipment and staff the oil spill removal organization and spill management team for the first 7 days of the response.

(v) This section must include job descriptions for each spill management team member within the organizational structure described in paragraph (b)(3)(iii) of this section. These job descriptions must include the responsibilities and duties of each spill management team member in a response action.

(vi) For facilities that handle, store, or transport group II through group IV petroleum oils, and that operate in waters where dispersant use is pre-authorized, this subsection of the plan must also separately list the resource providers and specific resources, including appropriately trained dispersant-application personnel, necessary to provide the dispersant capabilities required in this subpart. All resource providers and resources must be avail-

able by contract or other approved means as described in §154.1028(a). The dispersant resources to be listed within this section must include the following:

(A) Identification of each primary dispersant staging site to be used by each dispersant-application platform to meet the requirements of this subpart.

(B) Identification of the platform type, resource-providing organization, location, and dispersant payload for each dispersant-application platform identified. Location data must identify the distance between the platform's home base and the identified primary dispersant staging site for this section.

(C) For each unit of dispersant stockpile required to support the effective daily application capacity (EDAC) of each dispersant-application platform necessary to sustain each intended response tier of operation, identify the dispersant product resource provider, location, and volume. Location data must include the stockpile's distance to the primary staging sites where the stockpile would be loaded onto the corresponding platforms.

(D) If an oil spill removal organization has been evaluated by the Coast Guard, and its capability is equal to or exceeds the response capability needed by the owner or operator, the section may identify only the oil spill removal organization, and not the information required in paragraphs (b)(3)(vi)(A) through (b)(3)(vi)(C) of this section.

(vii) This subsection of the plan must also separately list the resource providers and specific resources necessary to provide aerial oil tracking capabilities required in this subpart. The oil tracking resources to be listed within this section must include the following:

(A) The identification of a resource provider; and

(B) Type and location of aerial surveillance aircraft that are ensured available, through contract or other approved means, to meet the oil tracking requirements of §154.1045(j).

(viii) For mobile facilities that operate in more than one COTP zone, the plan must identify the oil spill removal organization and the spill management

team in the applicable geographic-specific appendix. The oil spill removal organization(s) and the spill management team discussed in paragraph (b)(3)(iv) of this section must be included for each COTP zone in which the facility will handle, store, or transport oil in bulk.

(ix) For mobile facilities that operate in more than one COTP zone, the plan must identify the oil spill removal organization and the spill management team in the applicable geographic-specific appendix. The oil spill removal organization(s) and the spill management team discussed in paragraph (b)(3)(iv)(A) of this section must be included for each COTP zone in which the facility will handle, store, or transport oil in bulk.

(4) *Fish and wildlife and sensitive environments.* (i) This section of the plan must identify areas of economic importance and environmental sensitivity, as identified in the ACP, which are potentially impacted by a worst case discharge. ACPs are required under section 311(j)(4) of the FWPCA to identify fish and wildlife and sensitive environments. The applicable ACP shall be used to designate fish and wildlife and sensitive environments in the plan. Changes to the ACP regarding fish and wildlife and sensitive environments shall be included in the annual update of the response plan, when available.

(ii) For a worst case discharge from the facility, this section of the plan must—

(A) List all fish and wildlife and sensitive environments identified in the ACP which are potentially impacted by a discharge of persistent oils, non-persistent oils, or non-petroleum oils.

(B) Describe all the response actions that the facility anticipates taking to protect these fish and wildlife and sensitive environments.

(C) Contain a map or chart showing the location of those fish and wildlife and sensitive environments which are potentially impacted. The map or chart shall also depict each response action that the facility anticipates taking to protect these areas. A legend of activities must be included on the map page.

(iii) For a worst case discharge, this section must identify appropriate equipment and required personnel,

available by contract or other approved means as described in §154.1028, to protect fish and wildlife and sensitive environments which fall within the distances calculated using the methods outlined in this paragraph as follows:

(A) Identify the appropriate equipment and required personnel to protect all fish and wildlife and sensitive environments in the ACP for the distances, as calculated in paragraph (b)(4)(iii)(B) of this section, that the persistent oils, non-persistent oils, or non-petroleum oils are likely to travel in the noted geographic area(s) and number of days listed in table 2 of appendix C of this part;

(B) Calculate the distances required by paragraph (b)(4)(iii)(A) of this section by selecting one of the methods described in this paragraph;

(1) Distances may be calculated as follows:

(i) For persistent oils and non-petroleum oils discharged into non-tidal waters, the distance from the facility reached in 48 hours at maximum current.

(ii) For persistent and non-petroleum oils discharged into tidal waters, 15 miles from the facility down current during ebb tide and to the point of maximum tidal influence or 15 miles, whichever is less, during flood tide.

(iii) For non-persistent oils discharged into non-tidal waters, the distance from the facility reached in 24 hours at maximum current.

(iv) For non-persistent oils discharged into tidal waters, 5 miles from the facility down current during ebb tide and to the point of maximum tidal influence or 5 miles, whichever is less, during flood tide.

(2) A spill trajectory or model may be substituted for the distances calculated under paragraph (b)(4)(iii)(B)(1) of this section. The spill trajectory or model must be acceptable to the COTP.

(3) The procedures contained in the Environmental Protection's Agency's regulations on oil pollution prevention for non-transportation-related onshore facilities at 40 CFR part 112, appendix C, Attachment C-III may be substituted for the distances listed in non-tidal and tidal waters; and

(C) Based on historical information or a spill trajectory or model, the

COTP may require the additional fish and wildlife and sensitive environments also be protected.

(5) *Disposal Plan.* This subsection must describe any actions to be taken or procedures to be used to ensure that all recovered oil and oil contaminated debris produced as a result of any discharge are disposed according to Federal, state, or local requirements.

(c) *Training and exercises.* This section must be divided into the following two subsections:

(1) *Training procedures.* This subsection must describe the training procedures and programs of the facility owner or operator to meet the requirements in § 154.1050.

(2) *Exercise procedures.* This subsection must describe the exercise program to be carried out by the facility owner or operator to meet the requirements in § 154.1055.

(d) *Plan review and update procedures.* This section must address the procedures to be followed by the facility owner or operator to meet the requirements of § 154.1065 and the procedures to be followed for any post-discharge review of the plan to evaluate and validate its effectiveness.

(e) *Appendices.* This section of the response plan must include the appendices described in this paragraph.

(1) *Facility-specific information.* This appendix must contain a description of the facility's principal characteristics.

(i) There must be a physical description of the facility including a plan of the facility showing the mooring areas, transfer locations, control stations, locations of safety equipment, and the location and capacities of all piping and storage tanks.

(ii) The appendix must identify the sizes, types, and number of vessels that the facility can transfer oil to or from simultaneously.

(iii) The appendix must identify the first valve(s) on facility piping separating the transportation-related portion of the facility from the non-transportation-related portion of the facility, if any. For piping leading to a manifold located on a dock serving tank vessels, this valve is the first valve inside the secondary containment required by 40 CFR part 112.

(iv) The appendix must contain information on the oil(s) and hazardous material handled, stored, or transported at the facility in bulk. A material safety data sheet meeting the requirements of 29 CFR 1910.1200, 33 CFR 154.310(a)(5) or an equivalent will meet this requirement. This information can be maintained separately providing it is readily available and the appendix identifies its location. This information must include—

- (A) The generic or chemical name;
- (B) A description of the appearance and odor;
- (C) The physical and chemical characteristics;
- (D) The hazards involved in handling the oil(s) and hazardous materials. This shall include hazards likely to be encountered if the oil(s) and hazardous materials come in contact as a result of a discharge; and
- (E) A list of firefighting procedures and extinguishing agents effective with fires involving the oil(s) and hazardous materials.

(v) The appendix may contain any other information which the facility owner or operator determines to be pertinent to an oil spill response.

(2) *List of contacts.* This appendix must include information on 24-hour contact of key individuals and organizations. If more appropriate, this information may be specified in a geographic-specific appendix. The list must include—

- (i) The primary and alternate qualified individual(s) for the facility;
- (ii) The contact(s) identified under paragraph (b)(3)(iv) of this section for activation of the response resources; and
- (iii) Appropriate Federal, State, and local officials.

(3) *Equipment list and records.* This appendix must include the information specified in this paragraph.

(i) The appendix must contain a list of equipment and facility personnel required to respond to an average most probable discharge, as defined in § 154.1020. The appendix must also list the location of the equipment.

(ii) The appendix must contain a detailed listing of all the major equipment identified in the plan as belonging to an oil spill removal organization(s) that is available, by contract or other approved means as described in §154.1028(a), to respond to a maximum most probable or worst case discharge, as defined in §154.1020. The detailed listing of all major equipment may be located in a separate document referenced by the plan. Either the appendix or the separate document referenced in the plan must provide the location of the major response equipment.

(iii) It is not necessary to list response equipment from oil spill removal organization(s) when the organization has been classified by the Coast Guard and their capacity has been determined to equal or exceed the response capability needed by the facility. For oil spill removal organization(s) classified by the Coast Guard, the classification must be noted in this section of the plan. When it is necessary for the appendix to contain a listing of response equipment, it shall include all of the following items that are identified in the response plan: Skimmers; booms; dispersant application, in-situ burning, bioremediation equipment and supplies, and other equipment used to apply other chemical agents on the NCP Product Schedule (if applicable); communications, firefighting, and beach cleaning equipment; boats and motors; disposal and storage equipment; and heavy equipment. The list must include for each piece of equipment—

(A) The type, make, model, and year of manufacture listed on the nameplate of the equipment;

(B) For oil recovery devices, the effective daily recovery rate, as determined using section 6 of appendix C of this part;

(C) For containment boom, the overall boom height (draft and freeboard) and type of end connectors;

(D) The spill scenario in which the equipment will be used for or which it is contracted;

(E) The total daily capacity for storage and disposal of recovered oil;

(F) For communication equipment, the type and amount of equipment in-

tended for use during response activities. Where applicable, the primary and secondary radio frequencies must be specified.

(G) Location of the equipment; and

(H) The date of the last inspection by the oil spill removal organization(s).

(4) *Communications plan.* This appendix must describe the primary and alternate method of communication during discharges, including communications at the facility and at remote locations within the areas covered by the response plan. The appendix may refer to additional communications packages provided by the oil spill removal organization. This may reference another existing plan or document.

(5) *Site-specific safety and health plan.* This appendix must describe the safety and health plan to be implemented for any response location(s). It must provide as much detailed information as is practicable in advance of an actual discharge. This appendix may reference another existing plan requiring under 29 CFR 1910.120.

(6) *List of acronyms and definitions.* This appendix must list all acronyms used in the response plan including any terms or acronyms used by Federal, State, or local governments and any operational terms commonly used at the facility. This appendix must include all definitions that are critical to understanding the response plan.

[CGD 91-036, 61 FR 7917, Feb. 29, 1996, as amended by USCG-2000-7223, 65 FR 40058, June 29, 2000; USCG-2001-9286, 66 FR 33641, June 25, 2001; USCG-2008-0179, 73 FR 35014, June 19, 2008; USCG-2001-8661, 74 FR 45023, Aug. 31, 2009]

§ 154.1040 Specific requirements for facilities that could reasonably be expected to cause substantial harm to the environment.

(a) The owner or operator of a facility that, under §154.1015, could reasonably be expected to cause substantial harm to the environment, shall submit a response plan that meets the requirements of §154.1035, except as modified by this section.

(b) The facility's response activities section of the response plan need not list the facility or corporate organizational structure that will be used to manage the response, as required by §154.1035(b)(3)(iii).

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(c) The owner or operator of a facility must ensure the availability of response resources required to be identified in §154.1035(b)(3)(iv) by contract or other approved means described in §154.1028.

(d) A facility owner or operator must have at least 200 feet of containment boom and the means of deploying and anchoring the boom available at the spill site within 1 hour of the detection of a spill to respond to the average most probable discharge in lieu of the quantity of containment boom specified in §154.1045(c)(1). Based on site-specific or facility-specific information, the COTP may specify that additional quantities of containment boom are available within one hour. In addition, there must be adequate sorbent material for initial response to an average most probable discharge. If the facility is a fixed facility, the containment boom and sorbent material must be located at the facility. If the facility is a mobile facility, the containment boom and sorbent must be available locally and be at the site of the discharge within 1 hour of its discovery.

§ 154.1041 Specific response information to be maintained on mobile MTR facilities.

(a) Each mobile MTR facility must carry the following information as contained in the response plan when performing transfer operations:

(1) A description of response activities for a discharge which may occur during transfer operations. This may be a narrative description or a list of procedures to be followed in the event of a discharge.

(2) Identity of response resources to respond to a discharge from the mobile MTR facility.

(3) List of the appropriate persons and agencies (including the telephone numbers) to be contacted in regard to a discharge and its handling, including the National Response Center.

(b) The owner or operator of the mobile facility must also retain the information in this paragraph at the principal place of business.

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§ 154.1045 Response plan development and evaluation criteria for facilities that handle, store, or transport Group I through Group IV petroleum oils.

(a) The owner or operator of a facility that handles, stores, or transports Group I through Group IV petroleum oils shall use the criteria in this section to evaluate response resources identified in the response plan for the specified operating environment.

(1) The criteria in Table 1 of appendix C of this part are to be used solely for identification of appropriate equipment in a response plan. These criteria reflect conditions used for planning purposes to select mechanical response equipment and are not conditions that would limit response actions or affect normal facility operations.

(2) The response resources must be evaluated considering limitations for the COTP zones in which the facility operates, including but not limited to—

- (i) Ice conditions;
- (ii) Debris;
- (iii) Temperature ranges;
- (iv) Weather-related visibility; and
- (v) Other appropriate environmental conditions as determined by the COTP.

(3) The COTP may reclassify a specific body of water or location within the COTP zone. Any reclassifications will be identified by the COTP in the applicable ACP. Reclassifications may be to—

(i) A more stringent operating environment if the prevailing wave conditions exceed the significant wave height criteria during more than 35 percent of the year; or

(ii) A less stringent operating environment if the prevailing wave conditions do not exceed the significant wave height criteria for the less stringent operating environment during more than 35 percent of the year.

(b) Response equipment must—

(1) Meet or exceed the operating criteria listed in Table 1 of appendix C of this part;

(2) Function in the applicable operating environment; and

(3) Be appropriate for the petroleum oil carried.

(c) The response plan for a facility that handles, stores, or transports Group I through Group IV petroleum

oils must identify response resources that are available, by contract or other approved means as described in §154.1028(a)(1)(4), to respond to the facility's average most probable discharge. The response resources must include, at a minimum—

(1) 1,000 feet of containment boom or two times the length of the largest vessel that regularly conducts petroleum oil transfers to or from the facility, whichever is greater, and the means of deploying and anchoring the boom available at the spill site within 1 hour of the detection of a spill; and

(2) Oil recovery devices and recovered oil storage capacity capable of being at the spill site within 2 hours of the discovery of a petroleum oil discharge from a facility.

(d) The response plan for a facility that handles, stores, or transports Group I through Group IV petroleum oils must identify response resources that are available, by contract or other approved means as described in §154.1028(a)(1)(4), to respond to a discharge up to the facility's maximum most probable discharge volume.

(1) The response resources must include sufficient containment boom, oil recovery devices, and storage capacity for any recovery of up to the maximum most probable discharge planning volume, as contained in appendix C.

(2) The response resources must be appropriate for each group of petroleum oil identified in §154.1020 that is handled, stored, or transported by the facility.

(3) These response resources must be positioned such that they can arrive at the scene of a discharge within the following specified times:

(i) The equipment identified in paragraphs (c)(1) and (c)(2) of this section or in §154.1040(d) must arrive within the times specified in those paragraphs or that section, as appropriate.

(ii) In higher volume port areas and the Great Lakes, response resources must be capable of arriving on scene within 6 hours of the discovery of a petroleum oil discharge from a facility.

(iii) In all other locations, response resources must be capable of arriving on scene within 12 hours of the discovery of a petroleum oil discharge from a facility.

(4) The COTP may determine that mobilizing response resources to an area beyond the response times indicated in this paragraph invalidates the response plan. In this event, the COTP may impose additional operational restrictions (e.g., limitations on the number of transfers at a facility), or, at the COTP's discretion, the facility may operate with temporarily modified response plan development and evaluation criteria (e.g., modified response times, alternate response resources, etc.).

(e) The response plan for a facility that handles, stores, or transports Group I through Group IV petroleum oils must identify the response resources that are available, by contract or other approved means as described in §154.1028(a)(1)(4), to respond to the worst case discharge volume of petroleum oil to the maximum extent practicable.

(1) The location of these response resources must be suitable to meet the response times identified in paragraph (f) of this section for the applicable geographic area(s) of operation and response tier.

(2) The response resources must be appropriate for—

(i) The volume of the facility's worst case discharge;

(ii) Group(s) of petroleum oil as identified in §154.1020 that are handled, stored, or transported by the facility; and

(iii) The geographic area(s) in which the facility operates.

(3) The response resources must include sufficient boom, oil recovery devices, and storage capacity to recover the worst case discharge planning volumes.

(4) The guidelines in appendix C of this part must be used for calculating the quantity of response resources required to respond at each tier to the worst case discharge to the maximum extent practicable.

(5) When determining response resources necessary to meet the requirements of this section, a portion of those resources must be capable of use in close-to-shore response activities in shallow water. The following percentages of the response equipment identified for the applicable geographic area

must be capable of operating in waters of 6 feet or less depth.

- (i) Offshore—10 percent.
- (ii) Nearshore/inland/Great Lakes/rivers and canals—20 percent.

(6) The COTP may determine that mobilizing response resources to an area beyond the response times indicated in this paragraph invalidates the response plan. In this event, the COTP may impose additional operational restrictions (e.g., limitations on the number of transfers at a facility), or, at the COTP's discretion, the facility may be permitted to operate with temporarily modified response plan development and evaluation criteria (e.g., modified response times, alternate response resources, etc.).

(f) Response equipment identified in a response plan for a facility that handles, stores, or transports Group I through Group IV petroleum oils must be capable of arriving on scene within the times specified in this paragraph for the applicable response tier in a higher volume port area, Great Lakes, and in other areas. Response times for these tiers from the time of discovery of a discharge are—

	Tier 1 (hrs.)	Tier 2 (hrs.)	Tier 3 (hrs.)
Higher volume port area (except for a TAPAA facility located in Prince William Sound, see § 154.1135)	6	30	54
Great Lakes	12	36	60
All other river and canal, inland, nearshore, and offshore areas	12	36	60

(g) For the purposes of arranging for response resources for a facility that handles, stores, or transports Group I through Group IV petroleum oils, by contract or other approved means as described in §154.1028(a)(1)–(4), response equipment identified for Tier 1 plan credit must be capable of being mobilized and en route to the scene of a discharge within 2 hours of notification. The notification procedures identified in the plan must provide for notification and authorization of mobilization of identified Tier 1 response resources—

- (1) Either directly or through the qualified individual; and
- (2) Within 30 minutes of a discovery of a discharge or substantial threat of discharge.

(h) Response resources identified for Tier 2 and Tier 3 plan credit must be capable of arriving on scene within the time specified for the applicable tier.

(i) The owner or operator of a facility that handles, stores, or transports groups II through IV petroleum oils within the inland, nearshore, or offshore areas where pre-authorization for dispersant use exists must identify in their response plan, and ensure the availability of, through contract or other approved means, response resources capable of conducting dispersant operations within those areas.

(1) Dispersant response resources must be capable of commencing dispersant-application operations at the site of a discharge within 7 hours of the decision by the Federal On-Scene Coordinator to use dispersants.

(2) Dispersant response resources must include all of the following:

(i) Sufficient volumes of dispersants for application as required by paragraph (i)(3) of this section. Any dispersants identified in a response plan must be of a type listed on the National Oil and Hazardous Substances Pollution Contingency Plan Product Schedule (which is contained in 40 CFR part 300, and available online from the U.S. Government Printing Office).

(ii) Dispersant-application platforms capable of delivering and applying the dispersant on a discharge in the amounts as required by paragraph (i)(3) of this section. At least 50 percent of each EDAC tier requirement must be achieved through the use of fixed-wing, aircraft-based application platforms. For dispersant-application platforms not detailed within the EDSP, adequacy of performance criteria must be documented by presentation of independent evaluation materials (e.g., field tests and reports of actual use) that record the performance of the platform.

(iii) Dispersant-application systems that are consistent in design with, and are capable of applying dispersants within, the performance criteria in ASTM F1413-07 (incorporated by reference, see §154.106). For dispersant-application systems not fully covered by ASTM F1413-07, such as fire monitor-type applicators, adequacy of performance criteria must be documented by

presentation of independent evaluation materials (e.g., laboratory tests, field tests, and reports of actual use) that record the design of performance specifications.

(iv) Dispersant-application personnel trained in and capable of applying dispersants according to the recommended procedures contained within ASTM F1737-07 (incorporated by reference, *see* §154.106).

(3) Dispersant stockpiles, application platforms, and other supporting resources must be available in a quantity and type sufficient to treat a facility's worst-case discharge (as determined by using the criteria in appendix C, section 8) or in quantities sufficient to meet the requirements in Table 154.1045(i) of this section, whichever is the lesser amount.

TABLE 154.1045(i)—TIERS FOR EFFECTIVE DAILY APPLICATION CAPABILITY

	Response time for completed application (hours)	Dispersant application dispersant: oil treated in gallons (Gulf Coast)	Dispersant application dispersant: oil treated in gallons all other U.S.
Tier 1	12	8,250:165,000	4,125:82,500
Tier 2	36	23,375:467,000	23,375:467,000
Tier 3	60	23,375:467,000	23,375:467,000
Total	60	55,000:1,100,000	50,875:1,017,500

NOTE TO TABLE 154.1045(i): Gulf Coast Tier 1 is higher due to greater potential spill size and frequency in that area, and it is assumed that dispersant stockpiles would be centralized in the Gulf area. Alternative application ratios of peer-reviewed scientific evidence of improved capability may be considered upon submission to Coast Guard Headquarters. Contact Commandant (CG-RI), Attn: Office of Incident Management and Preparedness, U.S. Coast Guard Stop 7516, 2703 Martin Luther King Jr. Avenue SE., Washington, DC 20593-7516; telephone 202-372-2234.

(j) The owner or operator of a facility handling Groups I through IV petroleum oil as a primary cargo must identify in the response plan, and ensure the availability through contract or other approved means, of response resources necessary to provide aerial oil tracking to support oil spill assessment and cleanup activities. Facilities operating exclusively on inland rivers are not required to comply with this paragraph. Aerial oil tracking resources must:

(1) Be capable of arriving at the site of a discharge in advance of the arrival of response resources identified in the plan for tiers 1, 2, and 3 Worst-Case Discharge response times, and for a distance up to 50 nautical miles from shore (excluding inland rivers);

(2) Be capable of supporting oil spill removal operations continuously for three 10-hour operational periods dur-

ing the initial 72 hours of the discharge;

(3) Include appropriately located aircraft and personnel capable of meeting the response time requirement for oil tracking from paragraph (j)(1) of this section; and

(4) Include sufficient numbers of aircraft, pilots, and trained observation personnel to support oil spill removal operations, commencing upon initial assessment, and capable of coordinating on-scene cleanup operations, including dispersant and mechanical recovery operations. Observation personnel must be trained in:

(i) The protocols of oil-spill reporting and assessment, including estimation of slick size, thickness, and quantity; and

(ii) The use of assessment techniques in ASTM F1779-08 (incorporated by reference, *see* §154.106), and familiar with the use of other guides, such as NOAA's "Open Water Oil Identification Job Aid for Aerial Observation," and NOAA's "Characteristic Coastal Habitats" guide (available on the Internet at <http://response.restoration.noaa.gov/use> the following links in the order presented: Home|Emergency Response|Responding to Oil Spills).

(k) A response plan for a facility that handles, stores, or transports Group I through Group IV petroleum oils must

identify response resources with fire-fighting capability. The owner or operator of a facility that does not have adequate firefighting resources located at the facility or that can not rely on sufficient local firefighting resources must identify and ensure, by contract or other approved means as described in § 154.1028(a)(1)–(4), the availability of adequate firefighting resources. The response plan must also identify an individual located at the facility to work with the fire department for petroleum oil fires. This individual shall also verify that sufficient well-trained firefighting resources are available within a reasonable time to respond to a worst case discharge. The individual may be the qualified individual as defined in § 154.1020 and identified in the response plan or another appropriate individual located at the facility.

(1) The response plan for a facility that handles, stores, or transports Groups I through IV petroleum oils must identify equipment and required personnel available, by contract or other approved means as described in § 154.1028(a) (1)–(4), to protect fish and wildlife and sensitive environments.

(1) Except as set out in paragraph (k)(2) of this section, the identified response resources must include the quantities of boom sufficient to protect fish and wildlife and sensitive environments as required by § 154.1035(b)(4).

(2) The resources and response methods identified in a facility response plan must be consistent with the required resources and response methods to be used in fish and wildlife and sensitive environments, contained in the appropriate ACP. Facility owners or operators shall ensure that their response plans are in accordance with the ACP in effect 6 months prior to initial plan submission or the annual plan review required under § 154.1065(a). Facility owners or operators are not required to, but may at their option, conform to an ACP which is less than 6 months old at the time of plan submission.

(m) The response plan for a facility that handles, stores, or transports Groups I through IV petroleum oils must identify an oil spill removal organization(s) with response resources that are available, by contract or other

approved means as described in § 154.1028(a) (1)–(4), to effect a shoreline cleanup operation commensurate with the quantity of emulsified petroleum oil to be planned for in shoreline cleanup operations.

(1) Except as required in paragraph (1)(2) of this section, the shoreline cleanup response resources required must be determined as described in appendix C of this part.

(2) The resources and response methods identified in a facility response plan must be consistent with the required shoreline cleanup resources and methods contained in the appropriate ACP. Facility owners or operators shall ensure that their response plans are in accordance with the ACP in effect 6 months prior to initial plan submission or the annual plan review required under § 154.1065(a). Facility owners or operators are not required to, but may at their option, conform to an ACP which is less than 6 months old at the time of plan submission.

(n) Appendix C of this part describes the procedures to determine the maximum extent practicable quantity of response resources that must be identified and available, by contract or other approved means as described in § 154.1028(a) (1)–(4), for the maximum most probable discharge volume, and for each worst case discharge response tier.

(1) Included in appendix C of this part is a cap that recognizes the practical and technical limits of response capabilities that an individual facility owner or operator can be expected to contract for in advance.

(2) Table 5 in appendix C of this part lists the caps that apply in February 18, 1993, and February 18, 1998. Depending on the quantity and type of petroleum oil handled by the facility and the facility's geographic area of operations, the resource capability caps in this table may be reached. The owner or operator of a facility whose estimated recovery capacity exceeds the applicable contracting caps in Table 5 shall identify sources of additional equipment equal to twice the cap listed in Tiers 1, 2, and 3 or the amount necessary to reach the calculated planning

volume, whichever is lower. The identified resources must be capable of arriving on scene not later than the Tier 1, 2, and 3 response times in this section. No contract is required. While general listings of available response equipment may be used to identify additional sources, a response plan must identify the specific sources, locations, and quantities of equipment that a facility owner or operator has considered in his or her planning. When listing Coast Guard classified oil spill removal organization(s) which have sufficient removal capacity to recover the volume above the response capability cap for the specific facility, as specified in Table 5 in appendix C of this part, it is not necessary to list specific quantities of equipment.

(o) The Coast Guard will continue to evaluate the environmental benefits, cost efficiency and practicality of increasing mechanical recovery capability requirements. This continuing evaluation is part of the Coast Guard's long term commitment to achieving and maintaining an optimum mix of oil spill response capability across the full spectrum of response modes. As best available technology demonstrates a need to evaluate or change mechanical recovery capacities, a review of cap increases and other requirements contained within this subpart may be performed. Any changes in the requirements of this section will occur through a public notice and comment process. During this review, the Coast Guard will determine if established caps remain practicable and if increased caps will provide any benefit to oil spill recovery operations. The review will include, at least, an evaluation of:

- (1) Best available technologies for containment and recovery;
- (2) Oil spill tracking technology;
- (3) High rate response techniques;
- (4) Other applicable response technologies; and
- (5) Increases in the availability of private response resources.

[CGD 91-036, 61 FR 7917, Feb. 29, 1996, as amended by USCG-2001-8661, 74 FR 45024, Aug. 31, 2009; USCG-2014-0410, 79 FR 38436, July 7, 2014; USCG-2018-0874, 84 FR 30880, June 28, 2019]

§ 154.1047 Response plan development and evaluation criteria for facilities that handle, store, or transport Group V petroleum oils.

(a) An owner or operator of a facility that handles, stores, or transports Group V petroleum oils must provide information in his or her response plan that identifies—

(1) Procedures and strategies for responding to a worst case discharge of Group V petroleum oils to the maximum extent practicable; and

(2) Sources of the equipment and supplies necessary to locate, recover, and mitigate such a discharge.

(b) An owner or operator of a facility that handles, stores, or transports Group V petroleum oil must ensure that any equipment identified in a response plan is capable of operating in the conditions expected in the geographic area(s) in which the facility operates using the criteria in Table 1 of appendix C of this part. When evaluating the operability of equipment, the facility owner or operator must consider limitations that are identified in the ACPs for the COTP zones in which the facility operates, including—

(1) Ice conditions;

(2) Debris;

(3) Temperature ranges; and

(4) Weather-related visibility.

(c) The owner or operator of a facility that handles, stores, or transports Group V petroleum oil must identify the response resources that are available by contract or other approved means as described in §154.1028. The equipment identified in a response plan must include—

(1) Sonar, sampling equipment, or other methods for locating the petroleum oil on the bottom or suspended in the water column;

(2) Containment boom, sorbent boom, silt curtains, or other methods for containing the petroleum oil that may remain floating on the surface or to reduce spreading on the bottom;

(3) Dredges, pumps, or other equipment necessary to recover petroleum oil from the bottom and shoreline;

(4) Equipment necessary to assess the impact of such discharges; and

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(5) Other appropriate equipment necessary to respond to a discharge involving the type of petroleum oil handled, stored, or transported.

(d) Response resources identified in a response plan for a facility that handles, stores, or transports Group V petroleum oils under paragraph (c) of this section must be capable of being at the spill site within 24 hours of discovery of a discharge.

(e) A response plan for a facility that handles, stores, or transports Group V petroleum oils must identify response resources with firefighting capability. The owner or operator of a facility that does not have adequate firefighting resources located at the facility or that can not rely on sufficient local firefighting resources must identify and ensure, by contract or other approved means as described in §154.1028, the availability of adequate firefighting resources. The response plan must also identify an individual located at the facility to work with the fire department for petroleum oil fires. This individual shall also verify that sufficient well-trained firefighting resources are available within a reasonable response time to a worst case scenario. The individual may be the qualified individual as defined in §154.1020 and identified in the response plan or another appropriate individual located at the facility.

§ 154.1050 Training.

(a) A response plan submitted to meet the requirements of §154.1035 or §154.1040, as appropriate, must identify the training to be provided to each individual with responsibilities under the plan. A facility owner or operator must identify the method to be used for training any volunteers or casual laborers used during a response to comply with the requirements of 29 CFR 1910.120.

(b) A facility owner or operator shall ensure the maintenance of records sufficient to document training of facility personnel; and shall make them available for inspection upon request by the U.S. Coast Guard. Records for facility personnel must be maintained at the facility for 3 years.

(c) Where applicable, a facility owner or operator shall ensure that an oil

spill removal organization identified in a response plan to meet the requirements of this subpart maintains records sufficient to document training for the organization's personnel and shall make them available for inspection upon request by the facility's management personnel, the qualified individual, and U.S. Coast Guard. Records must be maintained for 3 years following completion of training.

(d) The facility owner or operator remains responsible for ensuring that all private response personnel are trained to meet the Occupational Safety and Health Administration (OSHA) standards for emergency response operations in 29 CFR 1910.120.

§ 154.1055 Exercises.

(a) A response plan submitted by an owner or operator of an MTR facility must include an exercise program containing both announced and unannounced exercises. The following are the minimum exercise requirements for facilities covered by this subpart:

(1) Qualified individual notification exercises (quarterly).

(2) Spill management team tabletop exercises (annually). In a 3-year period, at least one of these exercises must include a worst case discharge scenario.

(3) Equipment deployment exercises:

(i) Semiannually for facility owned and operated equipment.

(ii) Annually for oil spill removal organization equipment.

(4) Emergency procedures exercises (optional).

(5) Annually, at least one of the exercises listed in §154.1055(a)(2) through (4) must be unannounced. Unannounced means the personnel participating in the exercise must not be advised in advance, of the exact date, time and scenario of the exercise.

(6) The facility owner or operator shall design the exercise program so that all components of the response plan are exercised at least once every 3 years. All of the components do not have to be exercised at one time; they may be exercised over the 3-year period through the required exercises or through an Area exercise.

(b) A facility owner or operator shall participate in unannounced exercises,

as directed by the COTP. The objectives of the unannounced exercises will be to test notifications and equipment deployment for response to the average most probable discharge. After participating in an unannounced exercise directed by a COTP, the owner or operator will not be required to participate in another COTP initiated unannounced exercise for at least 3 years from the date of the exercise.

(c) A facility owner or operator shall participate in Area exercises as directed by the applicable On-Scene Coordinator. The Area exercises will involve equipment deployment to respond to the spill scenario developed by the Exercise Design Team, of which the facility owner or operator will be a member. After participating in an Area exercise, a facility owner or operator will not be required to participate in another Area exercise for at least 6 years.

(d) The facility owner or operator shall ensure that adequate records of all required exercises are maintained at the facility for 3 years. Records shall be made available to the Coast Guard upon request.

(e) The response plan submitted to meet the requirements of this subpart must specify the planned exercise program. The plan must detail the exercise program, including the types of exercises, frequency, scope, objectives and the scheme for exercising the entire response plan every 3 years.

(f) Compliance with the National Preparedness for Response Exercise Program (PREP) Guidelines will satisfy the facility response plan exercise requirements. These guidelines are available from the TASC DEPT Warehouse, 33141Q 75th Avenue, Landover, MD 20875 (fax: 301-386-5394, stock number USCG-X0241). Compliance with an alternative program that meets the requirements of paragraph (a) of this section and has been approved under § 154.1060 will also satisfy the facility response plan exercise requirements.

NOTE TO PARAGRAPH (f): The PREP guidelines are available online at http://dmses.dot.gov/docimages/pdf1a/198001_web.pdf.

[CGD 91-036, 61 FR 7917, Feb. 29, 1996, as amended by USCGD-2003-15404, 68 FR 37741, June 25, 2003]

§ 154.1057 Inspection and maintenance of response resources.

(a) A facility owner or operator required to submit a response plan under this part must ensure that—

(1) Containment booms, skimmers, vessels, and other major equipment listed or referenced in the plan are periodically inspected and maintained in good operating condition, in accordance with manufacturer's recommendations, and best commercial practices; and

(2) All inspection and maintenance is documented and that these records are maintained for 3 years.

(b) For equipment which must be inspected and maintained under this section the Coast Guard may—

(1) Verify that the equipment inventories exist as represented;

(2) Verify the existences of records required under this section;

(3) Verify that the records of inspection and maintenance reflect the actual condition of any equipment listed or referenced; and

(4) Inspect and require operational tests of equipment.

(c) This section does not apply to containment booms, skimmers, vessels, and other major equipment listed or referenced in the plan and ensured available from an oil spill removal organization through the written consent required under § 154.1028(a)(5).

§ 154.1060 Submission and approval procedures.

(a) The owner or operator of a facility to which this subpart applies shall submit one copy of a facility response plan meeting the requirements of this subpart to the COTP for initial review and, if appropriate, approval.

(b) The owner or operator of a facility to which this subpart applies shall include a statement certifying that the plan meets the applicable requirements of subparts F, G, H, and I of this part, as appropriate.

(c) For an MTR facility that is located in the inland response zone where the EPA Regional Administrator is the predesignated Federal On-Scene Coordinator, the COTP may consult with the EPA Federal On-Scene Coordinator prior to any final approval.

(d) For an MTR facility identified in § 154.1015(c) of this subpart that is also required to prepare a response plan under 40 CFR part 112, if the COTP determines that the plan meets all applicable requirements and the EPA Regional Administrator raises no objection to the response plan contents, the COTP will notify the facility owner or operator in writing that the plan is approved.

(e) The plan will be valid for a period of up to 5 years. The facility owner or operator must resubmit an updated plan every 5 years as follows:

(1) For facilities identified in only § 154.1015(b) of this subpart, the 5-year period will commence on the date the plan is submitted to the COTP.

(2) For facilities identified in § 154.1015(c) of this subpart, the 5-year period will commence on the date the COTP approves the plan.

(3) All resubmitted response plans shall be accompanied by a cover letter containing a detailed listing of all revisions to the response plan.

(f) For an MTR facility identified in § 154.1015(c)(2) the COTP will notify the facility owner or operator in writing that the plan is approved.

(g) If a COTP determines that a plan does not meet the requirements of this subpart either upon initial submission or upon 5-year resubmission, the COTP will return the plan to the facility owner or operator along with an explanation of the response plan's deficiencies. The owner or operator must correct any deficiencies in accordance with § 154.1070 and return the plan to the COTP within the time specified by the COTP in the letter describing the deficiencies.

(h) The facility owner or operator and the qualified individual and the alternative qualified individual shall each maintain a copy of the most current response plan submitted to the COTP. One copy must be maintained at the facility in a position where the plan is readily available to persons in charge of conducting transfer operations.

§ 154.1065 Plan review and revision procedures.

(a) A facility owner or operator must review his or her response plan(s) annu-

ally. This review shall incorporate any revisions to the plan, including listings of fish and wildlife and sensitive environments identified in the ACP in effect 6 months prior to plan review.

(1) For an MTR facility identified in § 154.1015(c) of this subpart as a "significant and substantial harm facility," this review must occur within 1 month of the anniversary date of COTP approval of the plan. For an MTR facility identified in § 154.1015(b) of this subpart, as a "substantial harm facility" this review must occur within 1 month of the anniversary date of submission of the plan to the COTP.

(2) The facility owner or operator shall submit any revision(s) to the response plan to the COTP and all other holders of the response plan for information or approval, as appropriate.

(i) Along with the revisions, the facility owner or operator shall submit a cover letter containing a detailed listing of all revisions to the response plan.

(ii) If no revisions are required, the facility owner or operator shall indicate the completion of the annual review on the record of changes page.

(iii) The COTP will review the revision(s) submitted by the owner or operator and will give written notice to the owner or operator of any COTP objection(s) to the proposed revisions within 30 days of the date the revision(s) were submitted to the COTP. The revisions shall become effective not later than 30 days from their submission to the COTP unless the COTP indicates otherwise in writing as provided in this paragraph. If the COTP indicates that the revision(s) need to be modified before implementation, the owner or operator will modify the revision(s) within the time period set by the COTP.

(3) Any required revisions must be entered in the plan and noted on the record of changes page.

(b) The facility owner or operator shall submit revisions to a previously submitted or approved plan to the COTP and all other holders of the response plan for information or approval within 30 days, whenever there is—

(1) A change in the facility's configuration that significantly affects the information included in the response plan;

(2) A change in the type of oil (petroleum oil group) handled, stored, or transported that affects the required response resources;

(3) A change in the name(s) or capabilities of the oil spill removal organization required by §154.1045;

(4) A change in the facility's emergency response procedures;

(5) A change in the facility's operating area that includes ports or geographic area(s) not covered by the previously approved plan. A facility may not operate in an area not covered in a plan previously submitted or approved, as appropriate, unless the revised plan is approved or interim operating approval is received under §154.1025; or

(6) Any other changes that significantly affect the implementation of the plan.

(c) Except as required in paragraph (b) of this section, revisions to personnel and telephone number lists included in the response plan do not require COTP approval. The COTP and all other holders of the response plan shall be advised of these revisions and provided a copy of the revisions as they occur.

(d) The COTP may require a facility owner or operator to revise a response plan at any time as a result of a compliance inspection if the COTP determines that the response plan does not meet the requirements of this subpart or as a result of inadequacies noted in the response plan during an actual pollution incident at the facility.

(e) If required by §154.1035(b)(3) or §154.1045, a new or existing facility owner or operator must submit the required dispersant and aerial oil tracking resource revisions to a previously submitted or approved plan, made pursuant to §154.1035(b)(3) or §154.1045, to the COTP and all other holders of the response plan for information or approval no later than February 22, 2011.

[CGD 91-036, 61 FR 7917, Feb. 29, 1996, as amended by USCG-2001-8661, 74 FR 45025, Aug. 31, 2009]

§ 154.1070 Deficiencies.

(a) The cognizant COTP will notify the facility owner or operator in writing of any deficiencies noted during review of a response plan, drills observed by the Coast Guard, or inspection of

equipment or records maintained in connection with this subpart.

(b) Deficiencies shall be corrected within the time period specified in the written notice provided by the COTP. The facility owner or operator who disagrees with a deficiency issued by the COTP may appeal the deficiency to the cognizant COTP within 7 days or the time specified by the COTP to correct the deficiency, whichever is less. This time commences from the date of receipt of the COTP notice. The owner or operator may request a stay from the COTP decision pending appeal in accordance with §154.1075.

(c) If the facility owner or operator fails to correct any deficiencies or submit a written appeal, the COTP may invoke the provisions of §154.1025 prohibiting the facility from storing, handling, or transporting oil.

§ 154.1075 Appeal process.

(a) Any owner or operator of a facility who desires to appeal the classification that a facility could reasonably be expected to cause substantial harm or significant and substantial harm to the environment, shall submit a written request to the cognizant COTP requesting review and reclassification by the COTP. The facility owner or operator shall identify those factors to be considered by the COTP. The factors to be considered by the COTP regarding reclassification of a facility include, but are not limited to, those listed in §154.1016(b). After considering all relevant material presented by the facility owner or operator and any additional material available to the COTP, the COTP will notify the facility owner or operator of the decision on the reclassification of the facility.

(b) Any facility owner or operator directly affected by an initial determination or action of the COTP may submit a written request to the cognizant COTP requesting review and reconsideration of the COTP's decision or action. The facility owner or operator shall identify those factors to be considered by the COTP in making his or her decision on reconsideration.

(c) Within 10 days of the COTP's decision under paragraph (b) of this section, the facility owner or operator may appeal the decision of the COTP to

the District Commander. This appeal shall be made in writing via the cognizant COTP to the District Commander of the district in which the office of the COTP is located.

(d) Within 30 days of the District Commander's decision, the facility owner or operator may formally appeal the decision of the District Commander. This appeal shall be submitted in writing to Commandant (CG-535) via the District Commander.

(e) When considering an appeal, the COTP, District Commander, or Commandant may stay the effect of the decision or action being appealed pending the determination of the appeal.

[CGD 91-036, 61 FR 7930, Feb. 29, 1996, as amended by CGD 96-026, 61 FR 33666, June 28, 1996; USCG-2010-0351, 75 FR 36284, June 25, 2010]

Subpart G—Additional Response Plan Requirements for a Trans-Alaska Pipeline Authorization Act (TAPAA) Facility Operating in Prince William Sound, Alaska

SOURCE: CGD 91-036, 61 FR 7930, Feb. 29, 1996, unless otherwise noted.

§ 154.1110 Purpose and applicability.

(a) This subpart establishes oil spill response planning requirements for a facility permitted under the Trans-Alaska Pipeline Authorization Act (TAPAA), in addition to the requirements of subpart F of this part. The requirements of this subpart are intended for use in developing response plans and identifying response resources during the planning process. They are not performance standards.

(b) The information required by this subpart must be included in the Prince William Sound facility-specific appendix to the facility response plan required by subpart F of this part.

§ 154.1115 Definitions.

In addition to the definitions in this section, the definitions in §§ 154.105 and 154.1020 apply to this subpart. As used in this subpart—

Crude oil means any liquid hydrocarbon mixture occurring naturally in the earth, whether or not treated to

render it suitable for transportation, and includes crude oil from which certain distillate fractions may have been removed, and crude oil to which certain distillate fractions may have been added.

Non-crude oil means any oil other than crude oil.

Prince William Sound means all State and Federal waters within Prince William Sound, Alaska, including the approach to Hinchinbrook Entrance out to and encompassing Seal Rocks.

§ 154.1120 Operating restrictions and interim operating authorization.

(a) The owner or operator of a TAPAA facility may not operate in Prince William Sound, Alaska, unless the requirements of this subpart as well as § 154.1025 have been met. The owner or operator of a TAPAA facility shall certify to the COTP that he or she has provided, through an oil spill removal organization required by § 154.1125, the necessary response resources to remove, to the maximum extent practicable, a worst case discharge or a discharge of 200,000 barrels of oil, whichever is greater, in Prince William Sound.

(b) Coast Guard approval of a TAPAA facility response plan is effective only so long as the appropriate Regional Citizens Advisory Council(s) is funded pursuant to the requirements of section 5002(k) of the Oil Pollution Act of 1990 (Pub. L. 101-380; 104 Stat. 484, 550).

§ 154.1125 Additional response plan requirements.

(a) The owner or operator of a TAPAA facility shall include the following information in the Prince William Sound appendix to the response plan required by subpart F of this part:

(1) *Oil spill removal organization.* Identification of an oil spill removal organization that shall—

(i) Perform response activities;

(ii) Provide oil spill removal and containment training, including training in the operation of prepositioned equipment for personnel, including local residents and fishermen, from the following locations in Prince William Sound:

- (A) Valdez;
- (B) Tatitlek;

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- (C) Cordova;
- (D) Whittier;
- (E) Chenega; and

(F) Fish hatcheries located at Port San Juan, Main Bay, Esther Island, Cannery Creek, and Solomon Gulch.

(iii) Provide a plan for training, in addition to the personnel listed in paragraph (a)(1)(ii) of this section, sufficient numbers of trained personnel to remove, to the maximum extent practicable, a worst case discharge; and

(iv) Address the responsibilities required in §154.1035(b)(3)(iii).

(2) *Exercises.* Identification of exercise procedures that must—

(i) Provide for two exercises of the oil spill removal organization each year that test the ability of the prepositioned equipment and trained personnel required under this subpart to perform effectively;

(ii) Consist of both announced and unannounced drills; and

(iii) Include design(s) for exercises that test either the entire appendix or individual components(s).

(3) *Testing, inspection, and certification.* Identification of a testing, inspecting, and certification program for the prepositioned response equipment required in §154.1130 that must provide for—

(i) Annual testing and equipment inspection in accordance with the manufacturer's recommended procedures, to include—

(A) Start-up and running under load all electrical motors, pumps, power packs, air compressors, internal combustion engines, and oil recovery devices; and

(B) Removal for inspection of no less than one-third of required boom from storage annually, such that all boom will have been removed and inspected within a period of 3 years; and

(ii) Records of equipment tests and inspection.

(iii) Use of an independent entity to certify that the equipment is on-site and in good operating condition and that required tests and inspection have been preformed. The independent entity must have appropriate training and expertise to provide this certification.

(4) *Prepositioned response equipment.* Identification and location of the prepositioned response equipment re-

quired in §154.1130 including the make, model, and effective daily recovery rate of each oil recovery resource.

(b) The owner or operator of a TAPAA facility shall submit to the COTP a schedule for the training and drills required by the geographic-specific appendix for Prince William Sound for the following calendar year.

(c) All records required by this section must be available for inspection by the COTP.

§ 154.1130 Requirements for prepositioned response equipment.

The owner or operator of a TAPAA facility shall provide the following prepositioned response equipment, located within Prince William Sound, in addition to that required by §154.1035, §154.1045, or §154.1050:

(a) On-water recovery equipment with a minimum effective daily recovery rate of 30,000 barrels capable of being a scene within 2 hours of notification of a discharge.

(b) On-water storage capacity of 100,000 barrels for recovered oily material capable of being on scene within 2 hours of notification of a discharge.

(c) On-water recovery equipment with a minimum effective daily recovery rate of 40,000 barrels capable of being on scene within 18 hours of notification of discharge.

(d) On-water storage capacity of 300,000 barrels for recovered oily material capable of being on scene within 12 hours of notification of a discharge.

(e) On-water recovery devices and storage equipment located in communities at strategic locations.

(f) Equipment as identified below, for the locations identified in §154.1125(a)(1)(ii) sufficient for the protection of the environment in these locations:

(1) Boom appropriate for the specific locations.

(2) Sufficient boats to deploy boom and sorbents.

(3) Sorbent materials.

(4) Personnel protective clothing and equipment.

(5) Survival equipment.

(6) First aid supplies.

(7) Buckets, shovels, and various other tools.

(8) Decontamination equipment.

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- (9) Shoreline cleanup equipment.
- (10) Mooring equipment.

(11) Anchored buoys at appropriate locations to facilitate the positioning of defensive boom.

(12) Other appropriate removal equipment for the protection of the environment as identified by the COTP.

§ 154.1135 Response plan development and evaluation criteria.

The following response times must be used in determining the on scene arrival time in Prince William Sound for the response resources required by §154.1045:

	Tier 1 (hrs.)	Tier 2 (hrs.)	tier 3 (hrs.)
Prince William Sound Area	12	24	36

§ 154.1140 TAPAA facility contracting with a vessel.

The owner or operator of a TAPAA facility may contract with a vessel owner or operator to meet some of all of the requirements of subpart G of part 155 of this chapter. The extent to which these requirements are met by the contractual arrangement will be determined by the COTP.

Subpart H—Response Plans for Animal Fats and Vegetable Oils Facilities

SOURCE: CGD 91-036, 61 FR 7931, Feb. 29, 1996, unless otherwise noted.

§ 154.1210 Purpose and applicability.

(a) The requirements of this subpart are intended for use in developing response plans and identifying response resources during the planning process. They are not performance standards.

(b) This subpart establishes oil spill response planning requirements for an owner or operator of a facility that handles, stores, or transports animal fats or vegetable oils including—

(1) A fixed MTR facility capable of transferring oil in bulk, to or from a vessel with a capacity of 250 barrels or more; and

(2) A mobile MTR facility used or intended to be used to transfer oil to or

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from a vessel with a capacity of 250 barrels or more.

[USCG-1999-5149, 65 FR 40825, June 30, 2000]

§ 154.1216 Facility classification.

(a) The Coast Guard classifies facilities that handle, store, or transport animal fats or vegetable oils as “substantial harm” facilities because they may cause substantial harm to the environment by discharging oil.

(b) The COTP may change the classification of a facility that handles, stores, or transports animal fats or vegetable oils. The COTP may consider the following factors, and any other relevant factors, before changing the classification of a facility:

- (1) The type and quantity of oils handled.
- (2) The spill history of the facility.
- (3) The age of the facility.
- (4) The public and commercial water supply intakes near the facility.
- (5) The navigable waters near the facility. *Navigable waters* is defined in 33 CFR part 2.36.
- (6) The fish, wildlife, and sensitive environments near the facility.

[USCG-1999-5149, 65 FR 40825, June 30, 2000, as amended by USCG-2008-0179, 73 FR 35014, June 19, 2008]

§ 154.1220 Response plan submission requirements.

(a) The owner or operator of an MTR facility identified in §154.1216 as a substantial harm facility, shall prepare and submit to the cognizant COTP a response plan that complies with this subpart and all sections of subpart F of this part, as appropriate, except §§154.1015, 154.1016, 154.1017, 154.1028, 154.1045 and 154.1047.

(b) The owner or operator of an MTR facility classified by the COTP under §154.1216(b) as a significant and substantial harm facility, shall prepare and submit for review and approval of the cognizant COTP a response plan that complies with this subpart and all sections of subpart F of this part, as appropriate, except §§154.1015, 154.1016, 154.1017, 154.1028, 154.1045 and 154.1047.

(c) In addition to the requirements in paragraph (a) of this section, the response plan for a mobile MTR facility

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must meet the requirements of §154.1041 subpart F.

[USCG-1999-5149, 65 FR 40825, June 30, 2000]

§154.1225 Specific response plan development and evaluation criteria and other requirements for fixed facilities that handle, store, or transport animal fats or vegetable oils.

(a) The owner or operator of a fixed facility that handles, stores, or transports animal fats or vegetable oils must include information in the response plan that identifies—

(1) The procedures and strategies for responding to a worst case discharge and to an average most probable discharge of an animal fat or vegetable oil to the maximum extent practicable; and

(2) Sources of the equipment and supplies necessary to locate, recover, and mitigate such a discharge.

(b) The owner or operator of a fixed facility must ensure the equipment listed in the response plan will operate in the geographic area(s) where the facility operates. To determine if the equipment will operate, the owner or operator must—

(1) Use the criteria in Table 1 and Section 2 of appendix C of this part; and

(2) Consider the limitations in the area contingency plan for the COTP zone where the facility is located, including

- (i) Ice conditions;
- (ii) Debris;
- (iii) Temperature ranges; and
- (iv) Weather-related visibility.

(c) The owner or operator of a facility that handles, stores, or transports animal fats or vegetable oils must name the personnel and list the equipment, including those that are specified in §154.1240, that are available by contract or by a method described in §154.1228(a). The owner or operator is not required, but may at their option, refer to the tables in Environmental Protection Agency regulations, 40 CFR 112, Appendix E, Section 10.0, Tables 6 and 7, to determine necessary response resources.

(d) The owner or operator of a facility that handles, stores, or transports animal fats or vegetable oils must ensure that the response resources in

paragraph (c) of this section are able to effectively respond to an incident within the amount of time indicated in the following table, unless otherwise specified in §154.1240:

	Tier 1 (hrs.)	Tier 2	Tier 3
Higher volume port area.	6	N/A	N/A.
Great Lakes	12	N/A	N/A.
All other river and canal, inland, near-shore, and offshore areas.	12	N/A	N/A.

(e) The owner or operator of a facility that handles, stores, or transports animal fats or vegetable oils must—

(1) List in the plan the personnel and equipment that the owner or operator will use to fight fires.

(2) If there is not enough equipment or personnel located at the facility, arrange by contract or a method described in §154.1228(a), or through a cooperative agreement with public fire-fighting resources, to have the necessary personnel and equipment available to fight fires.

(3) Identify an individual located at the facility who will work with the fire department on fires, involving an animal fat or vegetable oil. The individual—

(i) Verifies that there are enough trained personnel and operating equipment within a reasonable distance to the incident to fight fires.

(ii) Can be the qualified individual defined in §154.1020 or an appropriate individual located at the facility.

(f) For a fixed facility, except for facilities that are part of a non-transportation-related fixed onshore facility with a storage capacity of less than 42,000 gallons, the owner or operator must also ensure and identify, through contract or a method described in §154.1228, response resources for an average most probable discharge, including—

(1) At least 1,000 feet of containment boom or two times the length of the longest vessel that regularly conducts operations at the facility, whichever is greater, and the means of deploying and anchoring the boom within 1 hour of the discovery of an incident. Based on site-specific or facility-specific information, the COTP may require the

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facility owner or operator to make available additional quantities of containment boom within 1 hour of an incident;

(2) Adequate sorbent material located at the facility;

(3) Oil recovery devices and recovered oil storage capacity capable of being at the incident's site within 2 hours of the discovery of an incident; and

(4) Other appropriate equipment necessary to respond to an incident involving the type of oil handled.

(g) For a mobile facility or a fixed facility that is part of a non-transportation-related onshore facility with a storage capacity of less than 42,000 gallons, the owner or operator must meet the requirements of §154.1041, and ensure and identify, through contract or a method described in §154.1228, response resources for an average most probable discharge, including—

(1) At least 200 feet of containment boom and the means of deploying and anchoring the boom within 1 hour of the discovery of an incident. Based on site-specific or facility-specific information, the COTP may require the facility owner or operator to make available additional quantities of containment boom within 1 hour of the discovery of an incident;

(2) Adequate sorbent material capable of being at the site of an incident within 1 hour of its discovery;

(3) Oil recovery devices and recovered oil storage capacity capable of being at incident's site within 2 hours of the discovery of an incident; and

(4) Other equipment necessary to respond to an incident involving the type of oil handled.

(h) The response plan for a facility that is located in any environment with year-round preapproval for use of dispersants and that handles, stores, or transports animal fats and vegetables oils may request a credit for up to 25 percent of the worst case planning volume set forth by subpart F of this part. To receive this credit, the facility owner or operator must identify in the plan and ensure, by contract or other approved means as described in §154.1228(a), the availability of specified resources to apply the dispersants and to monitor their effectiveness. The extent of the credit for dispersants will

be based on the volumes of the dispersants available to sustain operations at the manufacturers' recommended dosage rates. Other spill mitigation techniques, including mechanical dispersal, may be identified in the response plan provided they are in accordance with the NCP and the applicable ACP. Resources identified for plan credit should be capable of being on scene within 12 hours of a discovery of a discharge. Identification of these resources does not imply that they will be authorized for use. Actual authorization for use during a spill response will be governed by the provisions of the NCP and the applicable ACP.

[CGD 91-036, 61 FR 7931, Feb. 29, 1996, as amended by USCG-1999-5149, 65 FR 40826, June 30, 2000]

§ 154.1228 Methods of ensuring the availability of response resources by contract or other approved means.

(a) When required in this subpart, the availability of response resources must be ensured by the following methods:

(1) The identification of an oil spill removal organization with specified equipment and personnel available within stipulated response times in specified geographic areas. The organization must provide written consent to being identified in the plan;

(2) A document which—

(i) Identifies the personnel, equipment, and services capable of being provided by the oil spill removal organization within stipulated response times in the specified geographic areas;

(ii) Sets out the parties' acknowledgment that the oil spill removal organization intends to commit the resources in the event of a response;

(iii) Permits the Coast Guard to verify the availability of the identified response resources through tests, inspections, and drills;

(iv) Is referenced in the response plan;

(3) Active membership in a local or regional oil spill removal organization that has identified specified personnel and equipment required under this subpart that are available to response to a discharge within stipulated response times in the specified geographic areas;

(4) Certification by the facility owner or operator that specified personnel and equipment required under this subpart are owned, operated, or under the direct control of the facility owner or operator, and are available within stipulated response times in the specified geographic areas; or

(5) A written contractual agreement with an oil spill removal organization. The agreement must identify and ensure the availability of specified personnel and equipment required under this subpart within stipulated response times in the specified geographic areas.

(b) The contracts and documents required in paragraph (a) of this section must be retained at the facility and must be produced for review upon request by the COTP.

§ 154.1240 Specific requirements for animal fats and vegetable oils facilities that could reasonably be expected to cause substantial harm to the environment.

(a) The owner or operator of a facility, classified under § 154.1216 as a facility that could reasonably be expected to cause substantial harm to the environment, must submit a response plan that meets the requirements of § 154.1035, except as modified by this section.

(b) The plan does not need to list the facility or corporate organizational structure that the owner or operator will use to manage the response, as required by § 154.1035(b)(3)(iii).

(c) The owner or operator must ensure and identify, by contract or a method described in § 154.1228, that the response resources required under § 154.1035(b)(3)(iv) are available for a worst case discharge.

[USCG-1999-5149, 65 FR 40827, June 30, 2000]

Subpart I—Response Plans for Other Non-Petroleum Oil Facilities

SOURCE: CGD 91-036, 61 FR 7932, Feb. 29, 1996, unless otherwise noted.

§ 154.1310 Purpose and applicability.

This subpart establishes oil spill response planning requirements for an owner or operator of a facility that handles, stores, or transports other non-petroleum oils. The requirements

of this subpart are intended for use in developing response plans and identifying response resources during the planning process. They are not performance standards.

§ 154.1320 Response plan submission requirements.

An owner or operator of a facility that handles, stores, or transports other non-petroleum oils shall submit a response plan in accordance with the requirements of this subpart, and with all sections of subpart F of this part, except §§ 154.1045 and 154.1047, which apply to petroleum oils.

§ 154.1325 Response plan development and evaluation criteria for facilities that handle, store, or transport other non-petroleum oils.

(a) An owner or operator of a facility that handles, stores, or transports other non-petroleum oils must provide information in his or her plan that identifies—

(1) Procedures and strategies for responding to a worst case discharge of other non-petroleum oils to the maximum extent practicable; and

(2) Sources of the equipment and supplies necessary to locate, recover, and mitigate such a discharge.

(b) An owner or operator of a facility that handles, stores, or transports other non-petroleum oils must ensure that any equipment identified in a response plan is capable of operating in the conditions expected in the geographic area(s) in which the facility operates using the criteria in Table 1 of appendix C of this part. When evaluating the operability of equipment, the facility owner or operator must consider limitations that are identified in the ACPs for the COTP zone in which the facility is located, including—

(1) Ice conditions;

(2) Debris;

(3) Temperature ranges; and

(4) Weather-related visibility.

(c) The owner or operator of a facility that handles, stores, or transports other non-petroleum oils must identify the response resources that are available by contract or other approved means as described in § 154.1028(a). The equipment identified in a response plan must include—

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(1) Containment boom, sorbent boom, or other methods for containing oil floating on the surface or to protect shorelines from impact;

(2) Oil recovery devices appropriate for the type of other non-petroleum oils handled; and

(3) Other appropriate equipment necessary to respond to a discharge involving the type of oil handled.

(d) Response resources identified in a response plan under paragraph (c) of this section must be capable of commencing an effective on-scene response within the times specified in this paragraph for the applicable operating area:

	Tier 1 (hrs.)	Tier 2	Tier 3
Higher volume port area	6	N/A	N/A
Great Lakes	12	N/A	N/A
All other river and canal, inland, near-shore, and offshore areas	12	N/A	N/A

(e) A response plan for a facility that handles, stores, or transports other non-petroleum oils must identify response resources with firefighting capability. The owner or operator of a facility that does not have adequate firefighting resources located at the facility or that cannot rely on sufficient local firefighting resources must identify and ensure, by contract or other approved means as described in §154.1028(a), the availability of adequate firefighting resources. The response plan must also identify an individual located at the facility to work with the fire department on other non-petroleum oil fires. This individual shall also verify that sufficient well-trained firefighting resources are available within a reasonable response time to a worst case scenario. The individual may be the qualified individual as defined in §154.1020 and identified in the response plan or another appropriate individual located at the facility.

(f) The response plan for a facility that is located in any environment with year-round preapproval for use of dispersants and that handles, stores, or transports other non-petroleum oils may request a credit for up to 25 percent of the worst case planning volume set forth by subpart F of this part. To receive this credit, the facility owner or operator must identify in the plan

and ensure, by contract or other approved means as described in §154.1028(a), the availability of specified resources to apply the dispersants and to monitor their effectiveness. The extent of the credit will be based on the volumes of the dispersant available to sustain operations at the manufacturers' recommended dosage rates. Identification of these resources does not imply that they will be authorized for use. Actual authorization for use during a spill response will be governed by the provisions of the NCP and the applicable ACP.

Subparts J–O [Reserved]

Subpart P—Marine Vapor Control Systems

SOURCE: USCG–1999–5150, 78 FR 42618, July 16, 2013, unless otherwise noted.

GENERAL

§ 154.2000 Applicability.

(a) Except as specified by paragraphs (b) through (g) of this section, this subpart applies to—

(1) Each facility that controls vapors emitted to or from vessel cargo tanks;

(2) A vessel, other than a tank vessel, that has a vapor processing unit located onboard for recovery, destruction, or dispersion of vapors from a tank vessel's cargo tanks;

(3) Certifying entities that review, inspect, test, and certificate facility vapor control systems (VCSs); or

(4) A facility VCS that receives cargo vapor from a vessel when the VCS is connected to a facility's main VCS that serves plant processing areas, such as tank storage areas or tank truck or railcar loading areas, unrelated to tank vessel operations. The requirements of this subpart apply between the vessel vapor connection and the point where the VCS connects to the facility's main VCS.

(b) Each facility VCS that began operating on or after July 23, 1990, and that is certified as in compliance with 33 CFR part 154, subpart E on August 15, 2013, or each existing tank barge cleaning facility VCS that meets the safety Standards of Navigation and Vessel Inspection Circular No. 1–96,

must comply with 33 CFR part 154, subpart P by August 15, 2016. Certifications, approvals of alternatives, and grants of exemption in effect on August 15, 2013, remain in effect after that date and as specified in the certification, approval, or grant.

(c) A facility with a Coast Guard-approved VCS operating prior to July 23, 1990, must comply with 33 CFR 154.2150 but otherwise need not comply with this subpart so long as it does not have any design or configuration alterations after its approval and receives cargo vapor only from the specific vessels for which it was originally approved.

(d) A facility that uses a vapor balancing system to transfer vapor from a railcar or a tank truck to a vessel cargo tank while offloading the vessel must obtain approval in writing from the Commandant and make that approval available for Coast Guard inspection upon request.

(e) A facility that transfers vapor from a facility tank to a cargo tank of a vessel which is not offloading cargo must obtain approval in writing from the Commandant and make that approval available for Coast Guard inspection upon request.

(f) A tank vessel that has a permanent or portable vapor processing unit located onboard must comply with applicable requirements of this subpart and 46 CFR part 39.

(g) This subpart does not apply to the collection of vapors of liquefied flammable gases as defined in 46 CFR 30.10-39.

(h) This subpart does not require a facility or a vessel to control vapor, or a vessel to take away vapor from facilities; however, if a facility operates a VCS to control vapor to or from vessels, the facility must comply with the requirements of this subpart.

(i) In this subpart, regulatory measurements, whether in the metric or English system, are sometimes followed by approximate equivalent measurements in parentheses, which are given solely for the reader's convenience. Regulatory compliance with the regulatory measurement is required.

§ 154.2001 Definitions.

As used in this subpart only:

Ambient temperature means the temperature of the environment in which an experiment is conducted or in which any physical or chemical event occurs.

Barge cargo connection means the point in a barge's cargo system where it connects with the hose assembly or loading arm used for cargo transfer.

Barge vapor connection means the point in a barge's piping system where it connects to a vapor collection hose or arm. This may be the same as the barge's cargo connection as it controls vapors during barge cargo tank-cleaning operations.

Base loading means a method of inerting, enriching, or diluting such that sufficient inerting, enriching, or diluting gas, for the worst concentration of vapor coming from the vessel, is injected into the vapor line during the entire loading operation so that the vapor mixture is inerted, enriched, or diluted at the maximum loading rate. For inerting and enriching systems, "worst concentration" means the vapor stream contains no cargo vapor. For a diluting system, "worst concentration" means the vapor stream is saturated with cargo vapor.

Captain of the Port (COTP) means the Coast Guard Captain of the Port as defined in 33 CFR 154.105.

Certifying entity means an individual or organization accepted by the Commandant to review plans, data, and calculations for vapor control system designs and to conduct inspections and observe tests of vapor control system installations.

Cleaning operation means any stripping, gas-freeing, or tank-washing operation of a barge's cargo tanks conducted at a cleaning facility.

Combustible liquid means any liquid that has a flashpoint above 80 °F (as determined from an open-cup tester, as used to test burning oils) and includes Grade D and Grade E combustible liquids defined in 46 CFR 30.10-15.

Commandant means Commandant (CG-ENG), U.S. Coast Guard, 2100 2nd St. SW., Stop 7126, Washington, DC 20593-7126.

Detonation arrester means a device that is acceptable to the Commandant and includes a detonation arrester that is designed, built, and tested in accordance with appendix A of this part or by

another method acceptable to the Commandant for arresting flames and detonations.

Diluting means introducing a non-flammable, non-combustible, and non-reactive gas with the objective of reducing the hydrocarbon content of a vapor mixture to below the lower flammable limit so that it will not burn.

Drip leg means a section of piping that extends below piping grade to collect liquid passing through the vapor line and that has a diameter no more than the diameter of the pipe in which it is installed.

Elevated temperature means the temperature that exceeds 70 percent of the auto-ignition temperature, in degrees Celsius, of the vapors being collected.

Enriching means introducing a flammable gas with the objective of raising the hydrocarbon content of a vapor mixture above the upper flammable limit so that it will not burn.

Existing vapor control system means a vapor control system that satisfies the requirements of 33 CFR part 154, subpart E as certified by a certifying entity, or a tank barge cleaning facility vapor control system that meets the safety Standards of Navigation and Vessel Inspection Circular No. 1–96 as certified by a certifying entity or approved by the U.S. Coast Guard, and that began operating prior to August 15, 2013.

Facility main vapor control system means a vapor control system that primarily serves facility processing areas unrelated to tank vessel operations, such as the plant process, tank storage areas, or tank truck or railcar loading areas.

Facility operations manual means the manual required by 33 CFR 154.300, the contents of which are described in 33 CFR 154.310.

Facility vapor connection means the point in a facility's vapor collection system where it connects to a vapor collection hose or the base of a vapor collection arm and is located at the dock as close as possible to the tank vessel to minimize the length of the flexible vapor collection hose, thus reducing the hazards associated with the hose.

Fail-safe means a piece of equipment or instrument that is designed such

that if any element should fail, it would go to a safe condition.

Fixed stripping line means a pipe extending to the low point of each cargo tank, welded through the deck and terminating above the deck with a valve plugged at the open end.

Flame arrester means a device that is designed, built, and tested in accordance with ASTM F 1273 or UL 525 (both incorporated by reference, see 33 CFR 154.106) for use in end-of-line applications for arresting flames.

Flame screen means a fitted single screen of corrosion-resistant wire of at least 30-by-30 mesh, or two fitted screens, both of corrosion-resistant wire, of at least 20-by-20 mesh, spaced apart not fewer than 12.7 millimeters (0.5 inch) or more than 38.1 millimeters (1.5 inches).

Flammable liquid means any liquid that gives off flammable vapors (as determined by flashpoint from an open-cup tester, as used to test burning oils) at or below a temperature of 80 °F, and includes Grades A, B, and C flammable liquids defined in 46 CFR 30.10–22.

Fluid displacement system means a system that removes vapors from a barge's cargo tanks during gas freeing through the addition of an inert gas or other medium into the cargo tank.

Fluid injection connection means the point in a fluid displacement system at which the fixed piping or hose that supplies the inert gas or other medium connects to a barge's cargo tanks or fixed piping system.

Gas freeing means the removal of vapors from a tank barge.

Grade A, B, C, D, or E means any Grade A, B, or C flammable liquid defined in 46 CFR 30.10–22 or any Grade D or E combustible liquid defined in 46 CFR 30.10–15.

High flash point cargoes means Grade E cargoes and cargoes having a closed-cup flash point higher than 60 °C (140 °F), carried at a temperature no higher than 5 °C (9 °F) below their flash points.

Inert condition or *inerted* means the oxygen content of the vapor space in a tank vessel's cargo tank is reduced to 60 percent or less by volume of the vapor's minimum oxygen concentration for combustion, or to 8 percent by volume or less for the vapor of crude oil,

gasoline blends, or benzene, by addition of an inert gas, in accordance with the inert gas requirements of 46 CFR 32.53 or 46 CFR 153.500.

Inerting means introducing an inert gas into a tank and/or piping system to lower the oxygen content of a vapor mixture.

Line clearing means the transfer of residual cargo from a cargo loading line toward a cargo tank by using compressed inert gas.

Liquid knockout vessel means a device, other than a drip leg, used to separate liquid from vapor.

Maximum allowable gas-freeing rate means the maximum volumetric rate at which a barge may be gas-freed during cleaning operations.

Maximum allowable stripping rate means the maximum volumetric rate at which a barge may be stripped during cleaning operations prior to the opening of any hatch and/or fitting in the cargo tank being stripped.

Maximum allowable transfer rate means the maximum volumetric rate at which a vessel may receive cargo or ballast.

Minimum oxygen concentration for combustion or *MOCC* means the lowest level of oxygen in a vapor or a vapor mixture that will support combustion.

Multi-breasted barge-loading operations are those in which barges load side by side with the outboard barge's vapor collection system connected to a facility vapor connection through the inboard barge, as opposed to single-breasted operations involving a single barge, and may also be known as "two barge, double-up" loading operations.

Multiple facility vapor collection system junction means the point in the vapor collection system where two or more branch lines originating from separate facility vapor connections are connected.

New vapor control system means a vapor control system that is not an existing vapor control system.

Padding means introducing into a tank and associated piping system with an inert gas or liquid which separates the cargo from air, and maintaining the condition.

Partially inerted means the oxygen content of the vapor space in a tank is reduced to below what is normally

present in the atmosphere by the addition of an inert gas such as nitrogen or carbon dioxide, but not to the concentration that meets the definition of "inert condition or inerted" in this section.

Pig means any device designed to maintain a tight seal within a cargo line while being propelled by compressed inert gas towards a cargo tank, for the purpose of transferring residual cargo from the cargo loading line to the cargo tank.

Pigging means the transfer of residual cargo from a cargo loading line by using compressed inert gas to propel a "pig" through the line toward a cargo tank.

Pre-transfer conference means the conference required by 33 CFR 156.120(w).

Purging means introducing an inert gas into a tank and/or piping system to further reduce the existing hydrocarbon and/or oxygen content to a level below which combustion cannot be supported if air is subsequently introduced into the tank or piping system.

Stripping means the removal, to the maximum extent practicable, of cargo residue remaining in the barge's cargo tanks and associated fixed piping system after cargo transfer or during cleaning operations.

Tank barge cleaning facility or *TBCF* means a facility used or capable of being used to conduct cleaning operations on a tank barge.

Transfer facility means a facility as defined in 33 CFR 154.105, excluding tank barge cleaning or stripping facilities.

Vacuum displacement system means a system that removes vapors from a barge's cargo tanks during gas freeing by sweeping air through the cargo tank hatch openings.

Vapor balancing means the transfer of vapor displaced by incoming cargo from the tank of a vessel or facility receiving cargo into a tank of the vessel or facility delivering cargo via facility vapor collection system.

Vapor collection system means an arrangement of piping and hoses used to collect vapor emitted to or from a vessel's cargo tanks and to transport the vapor to a vapor processing unit or a tank.

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Vapor control system or *VCS* means an arrangement of piping and equipment used to control vapor emissions collected to or from a vessel and includes the vapor collection system and the vapor processing unit or a tank.

Vapor destruction unit means a vapor processing unit that destroys cargo vapor by a thermal destruction method.

Vapor dispersion unit means a vapor processing unit that releases cargo vapor into the atmosphere through a venting system not located on the tank vessel.

Vapor processing unit means the components of a vapor control system that recover, destroy, or disperse vapor collected from a vessel.

Vapor recovery unit means a vapor processing unit that recovers cargo vapor by nondestructive means.

Vessel vapor connection means the point in a vessel's fixed vapor collection system where it connects to a vapor collection hose or arm.

CERTIFYING ENTITIES

§ 154.2010 Qualifications for acceptance as a certifying entity.

To qualify for acceptance as a vapor control system (VCS) certifying entity, the entity must demonstrate to the satisfaction of the Commandant that it possesses the following minimum qualifications:

- (a) The ability to review and evaluate design drawings and failure analyses for compliance to this subpart;
- (b) The knowledge of the applicable regulations of this subpart, including the standards incorporated by reference;
- (c) The ability to monitor and evaluate test procedures and results for compliance with the operational requirements of this subpart;
- (d) The ability to perform inspections and observe tests of bulk liquid cargo-handling systems;
- (e) The applicant must not be controlled by an owner or operator of a vessel or facility engaged in controlling vapor emissions;
- (f) The applicant must not be dependent upon Coast Guard acceptance under this section to remain in business; and
- (g) The person in charge of VCS certification must be a licensed profes-

sional engineer in a U.S. State or territory. A person in charge of VCS certification who is not a licensed professional engineer on August 15, 2013 must obtain that license from a U.S. State or territory by August 15, 2014.

[USCG-1999-5150, 78 FR 42618, July 16, 2013, as amended by 80 FR 7540, Feb. 11, 2015]

§ 154.2011 Application for acceptance as a certifying entity.

(a) An applicant seeking Coast Guard acceptance as a certifying entity of vapor control systems (VCSs) must submit a signed, written application to the Commandant containing the information described in paragraph (b) of this section. The applicant's signature certifies that the information in the application is true and that the applicant is not dependent upon Coast Guard acceptance under this section to remain in business and constitutes consent for the Coast Guard to verify any information contained in the application, through personal examination of persons named in the application, or otherwise. If an applicant knowingly and willfully provides any false statement or misrepresentation, or conceals a material fact in the application, the application may be denied or terminated, and the applicant may be subject to prosecution under the provisions of 18 U.S.C. 1001.

(b) An application must include the following general information:

- (1) The name and address of the applicant, including subsidiaries and divisions if applicable;
- (2) A description of the experience and qualifications of any person who would review or test systems on behalf of the applicant, showing that the person is familiar with or otherwise qualified to implement Coast Guard VCS regulations; and
- (3) A letter from a facility owner or operator stating his or her intent to use the services of the applicant to certify VCS installations.

(c) The Commandant reviews each application and either issues a letter of acceptance as a certifying entity to the applicant, or notifies the applicant that it is not accepted, and maintains a list of currently accepted certifying entities that is available to the public at <http://homeport.uscg.mil>.

(d) The acceptance of a certifying entity may be terminated by the Commandant for failure to review, inspect, or test a system properly in accordance with this subpart.

(e) A certifying entity may not certify a facility VCS if that certifying entity was involved in the design or installation of the system. "Design or installation" includes, but is not limited to—

- (1) Performing system design calculations;
- (2) Providing chemical data;
- (3) Developing plans, specifications, and drawings;
- (4) Conducting failure analysis; and
- (5) Installing systems or components.

(f) A certifying entity may not recertify a VCS design, configuration, or operational change if it was involved in that change, and may not conduct an operational review of a VCS if it has been involved in the design, installation, or operation of the VCS.

(g) A certifying entity may not conduct the failure analysis of a facility VCS it is certifying. The certifying entity may only point out shortcomings shown by the failure analysis and may not propose changes to correct the shortcomings.

(h) A certifying entity may not certify the VCS of any vessel or facility owner or operator that owns or has a controlling interest in the certifying entity.

CERTIFICATION, RECERTIFICATION, AND
OPERATIONAL REVIEW

§ 154.2020 Certification and recertification—owner/operator responsibilities.

(a) Prior to operating, a new vapor control system (VCS) installation must be certified under 33 CFR 154.2023 by a certifying entity as meeting the requirements of this subpart.

(b) A certified VCS or a Coast Guard-approved VCS must be recertified by a certifying entity under 33 CFR 154.2023 before it can—

- (1) Control vapors other than those for which it was originally certified;
- (2) Receive vapors from vessels other than those for which it was approved, if the VCS was in operation prior to July 23, 1990;

(3) Operate under any changed design or configuration;

(4) Operate as part of multi-breasted barge-loading operations, if the VCS was not originally approved or certified for such operations; or

(5) Be connected to a tank vessel if a pigging system is used to clear cargo in the cargo line back to the tank vessel.

(c) For a transfer facility, prior to operating a VCS to control vapor from a tank vessel during cargo loading line pigging to clear cargo in the cargo loading line back to the tank vessel, the cargo loading line pigging system must be reviewed by a certifying entity as meeting the requirements of 33 CFR 154.2104.

(d) To apply for certification, the owner or operator of a facility VCS must submit plans, calculations, specifications, and other related information, including a qualitative failure analysis, to the certifying entity. Suggested, but not mandatory, guidance for preparing a qualitative failure analysis can be found in the American Institute of Chemical Engineers publication "Guidelines for Hazard Evaluation Procedures," and in Military Standard MIL-STD-882B for a quantitative failure analysis. For assistance in locating those publications, contact the Commandant (CG-ENG), Attn: Office of Design and Engineering Standards, U.S. Coast Guard Stop 7509, Washington, DC 20593-7509, telephone 202-372-1418 or via email at *Hazmatstandards@uscg.mil*. The analysis must demonstrate that—

(1) The VCS can operate continuously and safely while controlling cargo vapors to or from tankships or tank barges over the full range of transfer rates expected at the facility;

(2) The VCS has the proper alarms and automatic shutdown systems required by this subpart to prevent an unsafe operation;

(3) The VCS has sufficient automatic or passive devices to minimize damage to personnel, property, and the environment if an accident were to occur;

(4) If a quantitative failure analysis is also conducted, the level of safety attained is at least one order of magnitude greater than that calculated for operating without a VCS; and

(5) If a facility uses a cargo line pigging system to clear cargo in the cargo

line back to the tank vessel with the VCS connected, the qualitative failure analysis must demonstrate that the cargo line pigging system has at least the same levels of safety required by paragraphs (d)(1), (2), and (3) of this section to prevent overpressure of the vessel's cargo tanks and account for the probability that the pig is destroyed during line-pigging operations.

(e) The VCS owner or operator must maintain at the facility—

(1) A copy of VCS design documentation, including plans, drawings, calculations, and specifications for the VCS;

(2) The facility operations manual, including the list of cargoes that the facility is approved to vapor control;

(3) Any certification or recertification letter issued under 33 CFR 154.2023; and

(4) Other records as required by 33 CFR 154.740.

[USCG–1999–5150, 78 FR 42618, July 16, 2013, as amended by USCG–2014–0410, 79 FR 38436, July 7, 2014; 80 FR 7540, Feb. 11, 2015]

§ 154.2021 Operational review—owner/operator responsibilities.

(a) Each facility vapor control system (VCS) must undergo an operational review by a certifying entity within five years of its initial certification or last operational review, to ensure its proper operation and maintenance.

(b) The VCS owner or operator must coordinate with the certifying entity and provide the entity with all necessary documentation and records to conduct the operational review.

(c) The VCS owner or operator must notify the Captain of the Port (COTP) of a scheduled operational review. The COTP, at his or her discretion, may observe the operational review.

(d) The VCS owner or operator must maintain, at the facility, the latest operational review letter issued under 33 CFR 154.2023.

§ 154.2022 Certification, recertification, or operational review—certifying entity responsibilities, generally.

Before the initial certification of a facility vapor control system (VCS), the certifying entity must perform

each of the tasks specified in this section.

(a) Review all VCS design documentation, including plans, drawings, calculations, specifications, and failure analysis, to ensure that the VCS design meets the requirements of this subpart.

(b) Conduct an initial onsite inspection to ensure that the VCS installation conforms to the VCS plans, drawings, and specifications reviewed.

(c) Conduct onsite reviews and observe tests to ensure the VCS's proper operation in accordance with its design and compliance with applicable regulations and the facility's operations manual and to ensure that—

(1) Each alarm and shutdown shown on the piping and instrumentation diagrams (P&IDs) and reviewed in the hazard analysis as part of the system responds properly, through simulation of emergency conditions to activate the alarm or shutdown;

(2) Maximum vacuum cannot be exceeded at the maximum operating conditions of any vapor-moving device, through testing of the vacuum breaker;

(3) VCS shutdown occurs correctly, through the startup of the VCS and tripping of each shutdown loop while the VCS is not connected to a vessel;

(4) VCS startup, normal operation, and shutdown occur properly, through observing the relevant portions of a test loading or unloading of one vessel, or a test cleaning of one tank barge at a tank barge cleaning facility; and that

(5) The automatic liquid block valve successfully stops flow of liquid to the vessel during a system shutdown, through observing the relevant portions of a test loading or test cargo tank cleaning.

(d) Review, for each cargo vapor the VCS will control, the cargo's chemical data and the VCS design to ensure that—

(1) Each vapor-controlled chemical is either specified in writing by the Commandant or listed in 46 CFR 30.25–1, 46 CFR 151.05, or Table 1 or Table 2 of 46 CFR 153;

(2) Each chemical's maximum experimental safe gap, minimum oxygen concentration for combustion (MOCC), and upper and lower limits of flammability have been correctly determined (this may but need not be in compliance

with Coast Guard guidance available at <http://homeport.uscg.mil>);

(3) Vapor properties and characteristics are addressed, including freezing point, polymerization potential, solubility, and cargo compatibility;

(4) The flash point for any cargo with a closed-cup flash point of 60 °C (140 °F) or higher is properly determined;

(5) The cargo's vapor growth rate has been correctly determined and the VCS complies with 33 CFR 154.2103(a) and (b) or 33 CFR 154.2203(a) or (b);

(6) Each detonation arrester used in the VCS is correct for each chemical's maximum experimental safe gap;

(7) Setpoints for each oxygen analyzer used in the VCS are correct for each chemical's MOCC;

(8) Setpoints for each oxygen or hydrocarbon analyzer used in the VCS are correct for each chemical's upper or lower flammability limit;

(9) The inerting, enriching, or dilution system used is adequate;

(10) Each vapor-controlled chemical is compatible with all VCS components and with other chemicals and with inerting, enriching, or diluting gases added to the VCS per 46 CFR part 150, Table I and Table II;

(11) The VCS's mechanical equipment and system are suitable;

(12) The VCS's vapor recovery or destruction unit has adequate capacity and is safe for each chemical;

(13) Any calculation to determine the duration of purging required by 33 CFR 154.2150(p) is correct; and that

(14) The VCS's failure analysis addresses any hazards presented with each chemical.

(e) Review the VCS prior to certifying it to control vapors from barge cargo tanks during multi-breasted barge loading operations, to confirm that—

(1) The overflow control system required by 33 CFR 154.2102 will process a liquid overflow condition within any one cargo tank on each barge;

(2) If multi-breasted loading is conducted using more than one liquid transfer hose from the shore facility, the facility is capable of activating the emergency shutdown system required by 33 CFR 154.550, and can automatically stop the cargo flow to each transfer hose simultaneously, in the event

an upset condition occurs that closes the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a);

(3) The facility operations manual has been modified to include the procedures for multi-breasted barge-loading operations; and

(4) The facility operations manual describes how to make proper connections, on the facility side, between the alarm and shutdown systems of the VCS and of each barge being loaded.

(f) Review a cargo line pigging system that will be used to clear cargo in the cargo line back to a tank vessel for compliance with 33 CFR 154.2104.

(g) Review the facility operations manual for compliance with 33 CFR 154.310(b).

(h) Review any test program used for instrument testing and calibration for compliance with 33 CFR 154.2180 and 33 CFR 154.2181.

(i) Review the facility's VCS training program for compliance with 33 CFR 154.2030 and 154.2031.

§ 154.2023 Recertification—certifying entity responsibilities, generally.

(a) Before the recertification of a facility vapor control system (VCS) the certifying entity must perform the reviews specified in 33 CFR 154.2022, except paragraphs (a) through (c).

(b) The certifying entity must review, inspect, and observe tests of a facility VCS's design or configuration alteration before recertifying a VCS that was certified or approved for operation prior to July 23, 1990, to ensure that the altered system complies with applicable regulations. In general, the certifying entity should perform the review, inspection, and observe tests as specified in 33 CFR 154.2022(a) through (c). However, depending on the extent of the alteration, the review, inspection, or test observing may not need to be as comprehensive as those for an initial certification.

§ 154.2024 Operational review—certifying entity responsibilities, generally.

In conducting an operational review the certifying entity must ensure that

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the vapor control system (VCS) is properly operating and maintained by performing the tasks specified in this section.

(a) Ensure the completeness, currency, and accuracy of the facility operations manual, training plans, and VCS test procedures.

(b) Confirm through training records that the current listed available facility persons in charge have been trained in compliance with 33 CFR 154.2030 or 154.2031.

(c) Confirm that recordkeeping and testing and inspection comply with 33 CFR 154.740 and 156.170.

(d) Verify that there has been no change to the VCS equipment or instrumentation since the last certification, recertification, or operational review to ensure that the certification letter is current.

(e) Verify proper marking, labeling, maintenance, and operation of VCS components, through visual inspection.

(f) Confirm that the originally certified liquid cargo transfer rate can still be attained in compliance with 33 CFR 154.2103 and 154.2107.

(g) Ensure that cargo transfer or tank-cleaning barge operational procedures are properly followed and the VCS operates properly, through observation of the initial stages of transfer or cleaning, including 24-hour pre-transfer tests required by 33 CFR 154.2150(b) or 33 CFR 154.2250(b), the pre-transfer conference, and initial system startup procedures.

§ 154.2025 Certification, recertification, or operational review—certifying entity documentation.

(a) If the certifying entity is satisfied that the facility's vapor control system (VCS) has successfully undergone the reviews, inspections, and tests required by 33 CFR 154.2022(a) for certification or recertification, and that the VCS will operate properly and safely, the certifying entity must certify or recertify the VCS by issuing a certification letter to the facility owner or operator, and by sending copies of the letter to the Captain of the Port (COTP) and the Commandant. The certification letter must refer by date to the certifying entity's letter of acceptance issued under 33 CFR 154.2011(c), and must—

(1) State that the facility complies with applicable regulations and with its operations manual, and list any exemptions to the applicable regulations that have been approved by the Coast Guard;

(2) Report on all reviews, inspections, and tests undergone by the VCS in accordance with 33 CFR 154.2022(a);

(3) List all plans and drawings that were reviewed by the certifying entity;

(4) State if the VCS may control vapors from tank barges that are required to have a shore-side, explosion-proof receptacle or an overfill control system required by 33 CFR 154.2102(a) and (b); and

(5) List all cargoes that the certifying entity approves for control by the VCS.

(b) If the certifying entity is satisfied that the facility's VCS has successfully undergone the operational review required by 33 CFR 154.2022(b), the certifying entity must issue an operational review letter to the facility owner or operator, and send copies of the letter to the COTP and the Commandant. The operational review letter must—

(1) List each item reviewed and inspected;

(2) Describe the transfer or cleaning operation observed; and

(3) Summarize the review's results.

PERSONNEL

§ 154.2030 Transfer facilities.

(a) Personnel in charge of a transfer operation using a vapor control system (VCS) must have completed a training program covering the particular VCS installed at the facility. As part of the training program, personnel must be able to demonstrate, through drills and display of practical knowledge, the proper VCS operational procedures for normal and emergency conditions. The training program must cover the following subjects:

(1) Purpose of the VCS;

(2) Principles of the VCS;

(3) Components of the VCS;

(4) Hazards associated with the VCS;

(5) Coast Guard regulations in this subpart;

(6) Operating procedures, including:

(i) Transfer, testing, and inspection requirements;

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- (ii) Pre-transfer procedures;
 - (iii) Chemicals approved for collection;
 - (iv) Material safety data sheet review;
 - (v) Connection procedures;
 - (vi) Startup procedures;
 - (vii) Normal operating conditions and how to handle deviations from normal conditions;
 - (viii) Normal shutdown procedures; and
 - (ix) Operating procedures for cargo line clearing if a cargo line clearance system is installed in accordance with 33 CFR 154.2104; and
- (7) Emergency procedures.

(b) Personnel overseeing VCS maintenance must be familiar with—

- (1) Inspection of detonation arresters; and
- (2) Procedures for equipment and instrumentation testing required by 33 CFR 156.170(g).

(c) Facility personnel in charge of a transfer operation using a VCS must be designated and qualified in compliance with 33 CFR 154.710 and the facility must maintain the training documentation required by 33 CFR 154.740(b).

§ 154.2031 Tank barge cleaning facilities.

(a) In addition to complying with 33 CFR 154.2030, a tank barge cleaning facility (TBCF) person-in-charge (PIC) of a barge cargo tank-cleaning operation that uses a vapor control system (VCS) must complete a training program covering the particular systems installed at the facility and on the barge. As part of the training program, personnel must be able to demonstrate, through drills and practical knowledge, the proper VCS operation procedures for normal and emergency conditions. The training program must—

(1) Satisfy the requirements of 33 CFR 154.2030(a)(1) through (7), except (a)(6)(i), (ii), and (ix), and 33 CFR 154.2030(b) and cover—

- (i) Purpose, principles, components, and hazards associated with stripping and gas-freeing;
- (ii) Special hazards associated with the accumulation and discharge of static electricity; and

(iii) Operating procedures, including cleaning, testing, and inspection requirements; pre-cleaning procedures; and safeguards to prevent static electricity discharge.

(b) In addition to the requirements contained in 33 CFR 154.710, no person may serve, and the facility operator may not use the services of anyone, as a facility PIC of a cleaning operation unless the person has been properly trained and certified by the facility with a minimum of 60 hours of experience in cleaning operations.

TRANSFER FACILITIES—VCS DESIGN AND INSTALLATION

§ 154.2100 Vapor control system, general.

(a) Vapor control system (VCS) design and installation must eliminate potential overpressure and vacuum hazards, overflow hazards, sources of ignition, and mechanical damage to the maximum practicable extent. Each remaining hazard source that is not eliminated must be specifically addressed in the protection system design and system operational requirements.

(b) Vapor collection system pipe and fitting components must be in accordance with ANSI B31.3 (incorporated by reference, see 33 CFR 154.106) with a maximum allowable working pressure (MAWP) of at least 150 pounds per square inch gauge (psig). Valves must be in accordance with ASME B16.34, 150 pound class (incorporated by reference, see 33 CFR 154.106). Flanges must be in accordance with ANSI B16.5 or ANSI B16.24, 150 pound class (both incorporated by reference, see 33 CFR 154.106). The following components and their associated equipment do not have a minimum specified MAWP, but must be constructed to acceptable engineering standards and have the appropriate mechanical strength to serve the intended purpose: knockout drums, liquid seals, blowers/compressors, flare stacks/incinerators, and other vapor processing units.

(c) All VCS electrical equipment must comply with NFPA 70 (2011) (incorporated by reference, see 33 CFR 154.106).

(d) Any pressure, flow, or concentration indication required by this part

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must provide a remote indicator on the facility where the cargo transfer system and VCS are controlled, unless the local indicator is clearly visible and readable from the operator's normal position at the control stations.

(e) Any condition requiring an alarm as specified in this part must activate an audible and visible alarm where the cargo transfer and VCSs are controlled.

(f) For a VCS installed after August 15, 2013, an alarm or shutdown must be activated if electrical continuity of an alarm or shutdown sensor required by this subpart is lost.

(g) The VCS piping surface temperature must not exceed 177 °C (350 °F) or 70 percent of the auto-ignition temperature in degrees Celsius of the vapors being transferred, whichever is lower, during normal operations. This must be achieved by either separating or insulating the entire VCS from external heat sources.

(h) The VCS must be equipped with a mechanism to eliminate any liquid condensate from the vapor collection system that carries over from the vessel or condenses as a result of an enrichment process.

(1) If a liquid knockout vessel is installed to eliminate any liquid condensate, it must have—

(i) A mechanism to indicate the level of liquid in the device;

(ii) A high liquid level sensor that activates an alarm, meeting the requirements of paragraph (e) of this section;

(iii) A high-high liquid level sensor that closes the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a), and shuts down any vapor-moving devices before carrying liquid over from the vessel to the vapor-moving device. One sensor with two stages may accomplish both this requirement and the requirement of paragraph (h)(1)(ii) of this section; and

(2) If a drip leg is used to eliminate any liquid condensate, it must be fitted with a mechanism to remove liquid from the low point.

(i) Vapor collection piping must be electrically grounded and must be electrically continuous.

(j) If the facility handles inerted vapors of cargoes containing sulfur, the facility must control heating from

pyrophoric iron sulfide deposits in the vapor collection line.

(k) All VCS equipment and components, including piping, hoses, valves, flanges, fittings, and gaskets, must be suitable for use with the vapor in the VCS.

§ 154.2101 Requirements for facility vapor connections.

(a) A remotely operated cargo vapor shutoff valve must be installed in the vapor collection line between the facility vapor connection and the nearest point where any inerting, enriching, or diluting gas is introduced into the vapor collection line, or where a detonation arrester is fitted. The valve must—

(1) Close within 30 seconds after detection of a shutdown condition of any component required by this subpart;

(2) Close automatically if the control signal or electrical power to the system is interrupted;

(3) Activate an alarm meeting 33 CFR 154.2100(e) when a signal to shut down is received from a component;

(4) Be capable of manual operation or manual activation;

(5) Have a local valve position indicator, or be designed so that the valve position can be readily determined from the valve handle or valve stem position; and

(6) If the valve seat is fitted with resilient material, be a Category A valve as defined by 46 CFR 56.20-15 and not allow appreciable leakage when the resilient material is damaged or destroyed.

(b) Except when a vapor collection arm is used, the first 1 meter (3.3 feet) of vapor piping downstream of the facility vapor connection must be—

(1) Painted in the sequence of red/yellow/red. The width of the red bands must be 0.1 meter (0.33 foot) and the width of the middle yellow band must be 0.8 meter (2.64 feet); and

(2) Labeled with the word "VAPOR" painted in black letters at least 50.8 millimeters (2 inches) high.

(c) Each facility vapor connection flange face must have a permanent stud projecting outward that is 12.7 millimeters (0.5 inch) in diameter and is at least 25.4 millimeters (1 inch) long. The stud must be located at the

top of the flange face, midway between boltholes, and in line with the bolthole pattern.

(d) Each hose that transfers vapors must—

(1) Have a design burst pressure of at least 25 pounds per square inch gauge (psig);

(2) Have a maximum allowable working pressure no less than 5 psig;

(3) Be capable of withstanding at least a 2 pounds per square inch (psi) vacuum without collapsing or constricting;

(4) Be electrically continuous with a maximum resistance of 10,000 ohms;

(5) Have flanges with—

(i) A bolthole arrangement complying with the requirements for 150 pound class flanges, ANSI B16.5 (incorporated by reference, see 33 CFR 154.106); and

(ii) One or more 15.9 millimeter (0.625 inch) diameter holes in the flange face, located midway between boltholes, and in line with the bolthole pattern;

(6) Be resistant to abrasion and kinking;

(7) Be compatible with vapors being controlled; and

(8) Have the last 1 meter (3.3 feet) of each end of the vapor hose marked in accordance with paragraph (b) of this section.

(e) Vapor hoses must be adequately supported to prevent kinking, collapse, or contact with any metal of the vessel or facility to prevent unintentional electrical bypassing of the insulating flange or the single length of non-conducting hose required by paragraph (g) of this section.

(f) Fixed vapor collection arms must—

(1) Meet the requirements of paragraphs (d)(1) through (5) of this section; and

(2) Have the last 1 meter (3.3 feet) of the arm marked in accordance with paragraph (b) of this section.

(g) The facility vapor connection must be electrically insulated from the vessel vapor connection in accordance with OCIMF ISGOTT section 17.5 (incorporated by reference, see 33 CFR 154.106). In order to prevent electrical arcing during connection and disconnection of the transfer hose/arm, the transfer hose/arm must be fitted

with an insulating flange or a single length of non-conducting hose to ensure electrical discontinuity between the vessel and facility. The insulating flange/hose should be inserted at the jetty end and must not be electrically bypassed. The installation, inspection, and testing of the insulating flange/hose must be in accordance with 46 CFR 35.35-4. For each vapor hose, only one insulating flange or non-conductive hose must be provided. See 46 CFR 35.35-4.

(h) A vapor collection system, fitted with a gas injection system that operates at a positive gauge pressure at the facility vapor connection, must be fitted with a means to prevent backflow of vapor to the vessel's vapor collection system during loading.

(i) Electrical bonding between vessel and shore must be in accordance with 46 CFR 35.35-5.

§ 154.2102 Facility requirements for vessel liquid overfill protection.

This section does not apply to facilities collecting vapors emitted from vessel cargo tanks while inerting, padding, or purging the cargo tanks with an inert gas and not loading cargo into the cargo tank.

(a) Each facility that receives cargo vapor from a tank barge that is fitted with overfill protection, in accordance with 46 CFR 39.2009(a)(1)(iii), must provide a 120-volt, 20-amp explosion-proof receptacle for the overfill protection system that meets—

(1) ANSI NEMA WD-6 (incorporated by reference, see 33 CFR 154.106);

(2) NFPA 70 (2011), Articles 406.9 and 501.145 (incorporated by reference, see 33 CFR 154.106); and

(3) 46 CFR 111.105-9.

(b) Each facility that receives cargo vapor from a tank barge that is fitted with an intrinsically safe cargo tank level sensor system complying with 46 CFR 39.2009(a)(2), as a means of overfill protection, must have an overfill control system on the dock capable of powering and receiving an alarm and shutdown signal from the cargo tank level sensor system that—

(1) Closes the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a) and activates the

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emergency shutdown system required by 33 CFR 154.550 when—

(i) A tank overfill signal is received from the barge; or

(ii) Electrical continuity of the cargo tank level sensor system is interrupted;

(2) Activates an audible and visible alarm that warns barge and facility personnel when a tank overfill signal, or an optional high-level signal corresponding to a liquid level lower than the tank overfill sensor setting, is received from the barge;

(3) Has a mechanism to test the alarms and automatic shutdown systems electrically and mechanically before operating the vapor control system (VCS);

(4) Has suitable means, such as approved intrinsic safety barriers able to accept passive devices, so that the overfill and optional alarm circuits on the barge side of the overfill control system, including cabling, normally closed switches, and pin and sleeve connectors, are intrinsically safe;

(5) Is labeled at the dock with the maximum allowable inductance (in millihenrys) and capacitance (in microfarads) to be connected to the facility overfill protection system as specified by the equipment manufacturer; and

(6) Has a female connecting plug for the tank barge level sensor system with a five-wire, 16-ampere connector body meeting IEC 60309-1 and IEC 60309-2 (both incorporated by reference, see 33 CFR 154.106), that is—

(i) Configured with pins S2 (N) and R1 (L3) for the tank overfill sensor circuit, pin G connected to the cabling shield, and pins N (L2) and T3 (L1) reserved for an optional high-level alarm connection;

(ii) Labeled “Connector for Barge Overfill Control System”; and

(iii) Connected to the overfill control system by a shielded flexible cable.

§ 154.2103 Facility requirements for vessel vapor overpressure and vacuum protection.

In this section, the requirements of having a flame arrester or a flame screen at the opening of a pressure relief valve or a vacuum relief valve apply only to facilities collecting va-

pors of flammable, combustible, or non-high flash point liquid cargoes.

(a) A facility’s vapor control system (VCS) must have the capacity for collecting cargo vapor at a rate of not less than the facility’s maximum liquid transfer rate for cargoes that are vapor controlled plus the vapor growth for the cargoes and any inerting, diluting, or enriching gas that may be added to the system. Vapor growth must be considered as 25 percent of the cargo’s saturated vapor pressure in pounds per square inch absolute (psia) at 115 °F, divided by 12.5 psia (the vapor pressure of gasoline at 115 °F), times the facility’s maximum liquid transfer rate, unless there is experimental data for actual vapor growth for turbulent transferring under the most severe conditions for vapor growth. If the cargo is transferred at temperatures above 115 °F, the cargo’s true vapor pressure (in psia) at the transferring temperature must be used when determining the vapor growth.

(b) A facility VCS must be designed to prevent the pressure in a vessel’s cargo tanks from going below 80 percent of the highest setting of any of the vessel’s vacuum relief valves or exceeding 80 percent of the lowest setting of any of the vessel’s pressure relief valves for a non-inerted tank vessel. A facility VCS also must be designed to prevent the pressure in a vessel’s cargo tanks from going below 0.2 pounds per square inch gauge (psig) or exceeding 80 percent of the lowest setting of any of the vessel’s pressure relief valves for an inerted tank vessel. The system must sustain the pressure in the vessel’s cargo tanks within this range at any cargo transfer rate less than or equal to the maximum transfer rate determined at the pre-transfer conference.

(c) The pressure measured at the facility vapor connection must be corrected for pressure drops across the vessel’s vapor collection system, vapor collection hose or arm, and vapor line up to the location of the pressure sensor.

(d) The facility vapor connection must have a pressure-sensing device that meets the installation requirements of paragraph (h) of this section, which activates an alarm that meets 33 CFR 154.2100(e) when the pressure at

the facility vapor connection exceeds either—

(1) The pressure corresponding to the upper pressure determined in paragraph (b) of this section; or

(2) A lower pressure agreed upon at the pre-transfer conference.

(e) If a facility draws vapor from a vessel with a vapor-moving device, the facility vapor connection must have a pressure-sensing device, which activates an alarm meeting 33 CFR 154.2100(e) when the pressure at the facility vapor connection falls below either—

(1) The pressure corresponding to the lower pressure determined in paragraph (b) of this section; or

(2) A higher pressure agreed upon at the pre-transfer conference.

(f) The facility vapor connection must have a pressure-sensing device, independent of the device used to activate the alarm required by paragraph (d) of this section, meeting the installation requirements of paragraph (h) of this section, which activates the emergency shutdown system required by 33 CFR 154.550 when the pressure at the facility vapor connection exceeds the lower of the following:

(1) A pressure corresponding to 90 percent of the vessel's lowest pressure relief valve setting, corrected for pressure drops across the vessel's vapor collection system, the vapor collection hose or arm, and any vapor line up to the point where the pressure sensor is located;

(2) A pressure corresponding to 90 percent of the setting of the pressure relief valve at the facility vapor connection, if the facility vapor connection is installed with a pressure relief valve; or

(3) A lower pressure than the pressure in paragraphs (f)(1) and (f)(2) of this section that is agreed upon at the pre-transfer conference.

(g) If a facility draws vapors from a vessel with a vapor-moving device, the facility vapor connection must have a pressure-sensing device, independent of the device used to activate the alarm required by paragraph (e) of this section, which closes the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a) when the vacuum at the facility vapor connection is

more than the higher (lesser vacuum) of the following:

(1) A vacuum corresponding to 90 percent of the vessel's highest vacuum relief valve setting;

(2) A vacuum corresponding to 90 percent of the setting of the vacuum relief valve at the facility vapor connection, if the facility vapor connection is installed with a vacuum relief valve; or

(3) A lesser vacuum than the vacuum in paragraphs (g)(1) and (g)(2) of this section that is agreed upon at the pre-transfer conference.

(h) The pressure-sensing devices required by paragraphs (d) and (f) of this section must be located in the vapor collection line between the facility vapor connection and the following:

(1) Any isolation valve, unless an interlock is provided that prevents operation of the system when the isolation valve is closed; and

(2) Any components that could plug and cause a blockage in the vapor line.

(i) A pressure-indicating device must be provided that displays the pressure in the vapor collection line between the facility vapor connection and any isolation valve or any devices which could cause a blockage in the vapor line.

(j) If a facility draws vapor from the vessel with a vapor-moving device capable of drawing more than 1 pound per square inch (psi) vacuum, a vacuum relief valve must be installed in the vapor collection line between the vapor-moving device and the facility vapor connection, which—

(1) Relieves at a predetermined pressure such that the pressure at the facility vapor connection is maintained at -1.0 psig (1.0 psig vacuum) or less vacuum;

(2) Has a relieving capacity equal to or greater than the capacity of the vapor-moving device;

(3) Has a flame arrester or flame screen fitted at the vacuum relief opening; and

(4) Has been tested for relieving capacity in accordance with paragraph 1.5.1.3 of API 2000 (incorporated by reference, see 33 CFR 154.106) with a flame arrester or flame screen fitted.

(k) When a facility collects cargo vapor through an extensive length of

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vapor piping, such as an undersea pipeline from a vessel moored offshore, before reaching the first pressure sensor and vacuum relief valve, the vacuum relief valve may be set at a vacuum greater than 1 psi vacuum, provided the pressure controls take into account the pressure drop across the vessel's vapor collection system, any vapor collection hoses, and the vapor piping as a function of the actual transfer rate.

(1) If the pressure in the vapor collection system can exceed 1.5 psig during a malfunction of a pressure regulator or control valve in an inerting, enriching, or diluting system, a pressure relief valve must—

(1) Be located between where the inerting, enriching, or diluting gas is introduced into the vapor collection system and the facility vapor connection;

(2) Relieve at the higher of the following two pressures:

(i) A pressure such that the pressure at the facility vapor connection does not exceed 1.5 psig; or

(ii) The lowest pressure relief valve setting of vessels that control vapors at the facility;

(3) Have a relieving capacity equal to or greater than the maximum capacity of the facility inerting, enriching, or diluting gas source flowing through the failed pressure regulator or control valve, taking into account the pressure drops across any flame arrester or discharge piping fitted at the relief valve's discharge;

(4) Have a flame arrester or flame screen fitted at the discharge opening, if the design does not secure a minimum vapor discharge velocity of 30 meters (98.4 feet) per second; and

(5) Have been tested for relieving capacity in accordance with paragraph 1.5.1.3 of API 2000.

(m) The relieving capacity test required by paragraph (1)(5) of this section must be carried out with a flame screen fitted at the discharge opening if—

(1) The design of the pressure relief valve does not secure a minimum vapor discharge velocity of 30 meters (98.4 feet) per second; and

(2) The discharge is not fitted with a flame arrester.

(n) A facility that collects vapors emitted from vessel cargo tanks while inerting, padding, or purging cargo tanks must—

(1) Provide a pressure-sensing device that activates an alarm meeting 33 CFR 154.2100(e) when the pressure of the inerting, padding, or purging gas exceeds either the pressure corresponding to the higher pressure determined in paragraph (b) of this section or a lower pressure agreed upon at the pre-transfer conference;

(2) Provide a pressure-sensing device, independent of the device required by paragraph (n)(1) of this section, which automatically stops the flow of inerting, padding, or purging gas to the vessel when the pressure of the inerting, padding, or purging gas exceeds 90 percent of the lowest setting of any pressure relief valve on the vessel; and

(3) Locate the pressure-sensing devices required by paragraphs (n)(1) and (n)(2) of this section in the inerting, padding, or purging gas piping downstream of any devices in the gas piping that could potentially isolate the vessel from the sensing devices.

§ 154.2104 Pigging system.

(a) If a pigging system is used to clear cargo in the cargo lines to the tank vessel while the vessel is connected to the facility vapor control system (VCS), the pigging system must be designed with the following safety features:

(1) A bypass loop installed in the main liquid cargo line that contains the pig-receiving device, through which all the liquid flow is channeled during pigging operations. The pig must act as a seal to separate the vessel from the compressed inert gas that is used to propel it as the pig travels from the pig launcher to the pig-receiving device;

(2) A mechanism for restricting liquid and gas flow so that the vessel, personnel, and environment are not endangered. The compressed inert gas flow capacity that this mechanism secures must not be more than 95 percent of the combined capacity of all vessel and facility VCS relief valves located upstream of the facility's remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a);

(3) A fast-action automatic shutoff valve such as a solenoid valve, which closes on a high-pressure signal from the pressure sensor required by 33 CFR 154.2103(f), located in the liquid bypass loop downstream of the pig-receiving device;

(4) An interlock with the main cargo line manual block valve so that line-clearing operations cannot begin unless the main cargo line manual block valve is closed; and

(5) An automatic means to detect arrival of the pig at the pig-receiving device.

(b) If a cargo line clearance system without using pigging is used to clear cargo in the cargo lines to the tank vessel while the vessel is connected to the facility VCS, the cargo line clearance system must be approved by the Commandant.

§ 154.2105 Fire, explosion, and detonation protection.

This section applies only to facilities that control vapors of flammable, combustible, or non-high flash point liquid cargoes.

(a) A vapor control system (VCS) with a single facility vapor connection that receives inerted cargo vapor from a vessel and processes it with a vapor recovery unit must—

(1) Be capable of inerting the vapor collection line in accordance with 33 CFR 154.2107(a) before receiving the vessel's vapor and have at least one oxygen analyzer, which satisfies the requirements of 33 CFR 154.2107(f)(1) and (2), (g), and (h)(2) and (3), sampling the vapor concentration continuously at a point as close as practicable to the facility vapor connection. The total pipe length between the analyzer and the facility vapor connection must not exceed 6 meters (19.7 feet); or

(2) Have a detonation arrester located as close as practicable to the facility vapor connection. The total pipe length between the detonation arrester and the facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source.

(b) A VCS with a single facility vapor connection that receives only inerted cargo vapor from a vessel and processes it with a vapor destruction unit must—

(1) Satisfy the requirements of paragraph (a)(1) of this section and have a detonation arrester located as close as practicable to the facility vapor connection. The oxygen analyzer required by paragraph (a)(1) can be located 4 meters (13.1 feet) downstream of the detonation arrester. The total pipe length between the detonation arrester and the facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source; or

(2) Have an inerting system that meets the requirements of 33 CFR 154.2107.

(c) A VCS with a single facility vapor connection that receives vapor from a vessel with cargo tanks that are not inerted or are partially inerted, and processes it with a vapor recovery unit must—

(1) Have a detonation arrester located as close as practicable to the facility vapor connection. The total pipe length between the detonation arrester and the facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source; or

(2) Have an inerting, enriching, or diluting system that meets the requirements of 33 CFR 154.2107.

(d) A VCS with a single facility vapor connection that receives vapor from a vessel with cargo tanks that are not inerted or are partially inerted, and processes the vapor with a vapor destruction unit must—

(1) Have a detonation arrester located as close as practicable to the facility vapor connection. The total pipe length between the detonation arrester and the facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation

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arrester and the facility vapor connection must be protected from any potential internal or external ignition source; and

(2) Have an inerting, enriching, or diluting system that satisfies the requirements of 33 CFR 154.2107.

(e) A VCS with multiple facility vapor connections that receives vapor from vessels with cargo tanks that carry inerted, partially inerted, non-inerted, or combinations of inerted, partially inerted, and non-inerted cargoes, and processes them with a vapor recovery unit, must have a detonation arrester located as close as practicable to each facility vapor connection. The total pipe length between the detonation arrester and each facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source.

(f) A VCS with multiple facility vapor connections that receives only inerted cargo vapor from vessels and processes it with a vapor destruction unit must—

(1) Satisfy the requirements of paragraph (a)(1) of this section for each facility vapor connection and have a detonation arrester located as close as practicable to each facility vapor connection. The oxygen analyzer required by paragraph (a)(1) can be located 4 meters (13.1 feet) downstream of the detonation arrester. The total pipe length between the detonation arrester and each facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source; or

(2) Have an inerting, enriching, or diluting system that meets the requirements of 33 CFR 154.2107.

(g) A VCS with multiple facility vapor connections that receives vapor from vessels with non-inerted or partially inerted cargoes, and processes the vapor with a vapor destruction unit must—

(1) Have a detonation arrester located as close as practicable to each facility vapor connection. The total pipe

length between the detonation arrester and each facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source; and

(2) Have an inerting, enriching, or diluting system that meets the requirements of 33 CFR 154.2107.

(h) A VCS with multiple facility vapor connections that simultaneously receives vapor from vessels with inerted, partially inerted, and non-inerted cargoes, and processes the vapor with a vapor destruction unit must—

(1) Have a detonation arrester located as close as practicable to each facility vapor connection. The total pipe length between the detonation arrester and each facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source; and

(2) Have either an inerting, enriching, or diluting system that meets the requirements of 33 CFR 154.2107, or a base loading system that meets the requirements of 33 CFR 154.2107(m).

(i) A VCS that uses a vapor balancing system in which cargo vapor from a vessel or facility storage tank is transferred through the facility vapor collection system to facility storage tanks or a vessel must meet the requirements of 33 CFR 154.2110.

(j) Each outlet of a VCS that vents to the atmosphere, except for a discharge vent from a vapor destruction unit or relief valve installed to comply with 33 CFR 154.2103(j) and (k) or 33 CFR 154.2203(e), (k), and (l), must have one of the following located at the outlet:

(1) A detonation arrester;

(2) An end-of-line flame arrester that meets ASTM F 1273 (incorporated by reference, see 33 CFR 154.106); or

(3) An end-of-line flame arrester that meets UL 525 (incorporated by reference, see 33 CFR 154.106) if—

(i) The discharge vent stream's total flammable concentration is proven to be less than 50 percent of the lower

flammable limit, or the stream's oxygen concentration is proven to be less than 70 percent by volume of the MOCC, at all times by an outlet concentration analyzer for carbon beds, proof of correct operating temperature for refrigeration systems, or proof of scrubbing medium flow for scrubbers; and

(ii) The proving devices in paragraph (j)(2)(i) of this section close the remotely operated cargo vapor shutoff valve required in 33 CFR 154.2101(a) and close the automatic liquid cargo loading valve if operating outside the conditions necessary to maintain the discharge vent non-combustible.

§ 154.2106 Detonation arresters installation.

This section applies only to facilities collecting vapors of flammable, combustible, or non-high flash point liquid cargoes.

(a) Detonation arresters must be installed in accordance with the guidelines outlined in the arrester manufacturer's acceptance letter provided by the Coast Guard.

(b) On either side of a detonation arrester, line size expansions must be in a straight pipe run and must be no closer than 120 times the pipe's diameter from the detonation arrester unless the manufacturer has test data to show the expansion can be closer.

§ 154.2107 Inerting, enriching, and diluting systems.

This section applies only to facilities that control vapors of flammable, combustible, or non-high flash point liquid cargoes.

(a) Before receiving cargo vapor, a vapor control system (VCS) that uses a gas for inerting, enriching, or diluting must be capable of inerting, enriching, or diluting the vapor collection system, at a minimum of two system volume exchanges of inerting, enriching, or diluting gas, downstream of the injection point.

(b) A VCS that uses an inerting, enriching, or diluting system must be equipped, except as permitted by 33 CFR 154.2105(a), with a gas injection and mixing arrangement located as close as practicable to the facility vapor connection and no closer than 10

meters (32.8 feet) upstream from the vapor processing unit or the vapor-moving device that is not protected by a detonation arrester required by 33 CFR 154.2108(b). The total pipe length between the arrangement and the facility vapor connection must not exceed 22 meters (72.2 feet). The arrangement must be such that it provides complete mixing of the gases within 20 pipe diameters of the injection point. The vapor piping between the arrangement and the facility vapor connection must be protected from any potential internal or external ignition source.

(c) A VCS that uses an inerting or enriching system may not be operated at a vacuum after the injection point unless—

(1) There are no vacuum relief valves or other devices that could allow air into the vapor collection system downstream of the injection point, and pipe connections are flanged, threaded, or welded so no air can leak into the VCS; or

(2) An additional analyzer is used to monitor the vapor concentration downstream of such device and a mechanism is provided to inject additional inerting or enriching gas.

(d) A VCS that uses analyzers to control the amount of inerting, enriching, or diluting gas injected into the vapor collection line must be equipped with at least two analyzers. The analyzers must be connected so that—

(1) When two oxygen analyzers are used, the higher oxygen concentration reading controls the inerting or enriching system and activates the alarm and automatic shutdown system required by paragraph (h), (j), or (k)(2) of this section;

(2) When voting systems using more than two oxygen analyzers are used, the majority pair controls the inerting or enriching system and activates the alarm and automatic shutdown system required by paragraph (h), (j), or (k)(2) of this section;

(3) When two hydrocarbon analyzers are used, the lower hydrocarbon concentration reading controls the enriching system and activates the alarm and automatic shutdown system required by paragraph (i) of this section;

(4) When voting systems using more than two hydrocarbon analyzers are

used, the majority pair controls the enriching system and activates the alarm and automatic shutdown system required by paragraph (i) of this section;

(5) When two hydrocarbon analyzers are used, the higher hydrocarbon concentration reading controls the diluting system and activates the alarm and automatic shutdown system required by paragraph (l) of this section; and

(6) When voting systems using more than two hydrocarbon analyzers are used, the majority pair controls the diluting system and activates the alarm and automatic shutdown system required by paragraph (l) of this section.

(e) A VCS that uses volumetric measurements to control the amount of inerting, enriching, or diluting gas injected into the vapor collection line must be equipped, except as permitted by paragraph (m) of this section, with at least one analyzer to activate the alarms and automatic shutdown systems required by this section.

(f) Each oxygen or hydrocarbon analyzer required by this section must—

(1) Be installed in accordance with API 550 (incorporated by reference, see 33 CFR 154.106);

(2) Have a system response time of not more than one minute from sample input to 95 percent of final stable value as tested per 33 CFR 154.2180 and 33 CFR 154.2181; and

(3) Continuously sample the vapor concentration not more than 30 pipe diameters from the gas injection point.

(g) A VCS must not use oxygen analyzers that operate at elevated temperatures (*i.e.*, zirconia oxide or thermomagnetic).

(h) An inerting system must—

(1) Supply sufficient inert gas to the vapor stream to ensure that the oxygen concentration downstream of the injection point is maintained at or below 60 percent by volume of the minimum oxygen concentration for combustion (MOCC) for the specific combination of cargo vapors and inert gas being processed, which may be determined by using Coast Guard guidance available at <http://homeport.uscg.mil>;

(2) Activate an alarm that satisfies the requirements of 33 CFR 154.2100(e) when the oxygen concentration in the vapor collection line exceeds 60 percent by volume of the MOCC for the specific

combination of cargo vapors and inert gas being processed, which may be determined by using Coast Guard guidance available at <http://homeport.uscg.mil>;

(3) Close the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a) when the oxygen concentration in the vapor collection line exceeds 70 percent by volume of the MOCC for the specific combination of cargo vapors and inert gas being processed, which may be determined by using Coast Guard VCS guidance available at <http://homeport.uscg.mil>;

(4) Have a detonation arrester and a mechanism to prevent the backflow of flammable vapors installed between the combustion device and the inert gas injection point, if a combustion device is used to produce the inert gas; and

(5) Have an alarm value in paragraph (h)(2) of this section that is at least one percentage point less than the shutdown value in paragraph (h)(3) of this section. If the analyzers used to measure oxygen concentrations cannot accurately differentiate between the alarm value and the shutoff value, the alarm value must be lowered until the analyzers become operable.

(i) An enriching system must—

(1) Supply sufficient compatible hydrocarbon vapor to the vapor stream to make sure that the total flammable concentration downstream of the injection point is maintained either at or above 170 percent by volume of the upper flammable limit or above the upper flammable limit plus 10 percentage points, whichever is lower;

(2) Activate an alarm that satisfies the requirements of 33 CFR 154.2100(e) when the total flammable concentration in the vapor collection line either falls below 170 percent by volume of the upper flammable limit or below the upper flammable limit plus 10 percentage points, whichever is lower;

(3) Close the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a) when the total flammable concentration in the vapor collection line either falls below 150 percent by volume of the upper flammable limit or below the upper flammable limit plus 7.5 percentage points, whichever is lower; and

(4) Have an upper flammable limit listed in paragraphs (i)(1), (i)(2), and (i)(3) of this section which is either the cargo's upper flammable limit or the enriching gas's upper flammable limit, whichever is higher. Alternatively, the mixture's upper flammable limit, which may be determined by using methods found in Coast Guard guidance available at <http://homeport.uscg.mil>, may be used.

(j) Oxygen analyzers may be used instead of hydrocarbon analyzers in a VCS using an enriching system that receives cargo vapor only from a vessel with non-inerted cargo tanks, providing that the analyzers—

(1) Activate an alarm satisfying the requirements of 33 CFR 154.2100(e) when the oxygen concentration in the vapor collection line exceeds a level corresponding to either a total flammable concentration of 170 percent by volume of the upper flammable limit or the upper flammable limit plus 10 percentage points, whichever yields a higher oxygen concentration;

(2) Close the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a) when the oxygen concentration in the vapor collection line exceeds a level corresponding to either a total flammable concentration of 150 percent by volume of the upper flammable limit or the upper flammable limit plus 7.5 percentage points, whichever yields a higher oxygen concentration;

(3) Have an alarm value in paragraph (j)(1) of this section that is at least one percentage point less than the shutdown value in paragraph (j)(2) of this section. If the oxygen analyzers used to measure oxygen concentrations cannot accurately differentiate between the alarm value and the shutdown value, the alarm value must be lowered until the analyzers become operable; and

(4) Have an upper flammable limit listed in paragraphs (j)(1) and (j)(2) of this section which is either the cargo's upper flammable limit or the enriching gas's upper flammable limit, whichever is higher. Alternatively, the mixture's upper flammable limit, which may be determined by using methods found in Coast Guard VCS guidance available at <http://homeport.uscg.mil>, may be used.

(k) An enriching system may be used in a VCS that receives inerted cargo vapor from a vessel if—

(1) Hydrocarbon analyzers are used to comply with paragraphs (i)(2) and (i)(3) of this section; or

(2) Oxygen analyzers are used, in which case the analyzers must—

(i) Activate an alarm meeting 33 CFR 154.2100(e) when the oxygen concentration in the vapor collection line exceeds 60 percent by volume of the MOCC for the specific combination of cargo vapors and gases; and

(ii) Close the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a) when the oxygen concentration exceeds 70 percent by volume of the MOCC for the specific combination of cargo vapors and gases; and

(3) The MOCC in paragraphs (k)(2)(i) and (k)(2)(ii) of this section is either the cargo's MOCC or the enriching gas's MOCC, whichever is lower. Alternatively, the mixture's MOCC, which may be determined using Coast Guard VCS guidance available at <http://homeport.uscg.mil>, may be used.

(1) An air dilution system must—

(1) Supply a sufficient amount of additional air to the vapor stream to keep the total flammable concentration downstream of the injection point below 30 percent by volume of the lower flammable limit;

(2) Activate an alarm that satisfies the requirements of 33 CFR 154.2100(e) when the total flammable concentration in the vapor collection line exceeds 30 percent by volume of the lower flammable limit; and

(3) Close the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a) when the total flammable concentration in the vapor collection line exceeds 50 percent by volume of the lower flammable limit.

(m) An enriching system may use a base loading method to control the amount of enriching gas in a vapor collection system if—

(1) The flow rate of enriching gas is determined by assuming the vapor entering the facility vapor connection consists of 100 percent air;

(2) Two independent devices are used to verify the correct enriching gas volumetric flow rate. One of the two devices must be a flow meter;

(3) One of the devices activates an alarm that satisfies the requirements of 33 CFR 154.2100(e) when the amount of enriching gas added results in a total flammable concentration in the vapor collection line either below 170 percent by volume of the upper flammable limit or below the upper flammable limit plus 10 percentage points, whichever is lower;

(4) The second device activates closure of the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a) when the amount of enriching gas added results in a total flammable concentration in the vapor collection line either below 150 percent by volume of the upper flammable limit or below the upper flammable limit plus 7.5 percentage points, whichever is lower; and

(5) The upper flammable limit in paragraphs (m)(3) and (4) of this section is either the cargo's upper flammable limit or the enriching gas's upper flammable limit, whichever is higher. Alternatively, the mixture's upper flammable limit, which may be determined using Coast Guard guidance available at <http://homeport.uscg.mil>, may be used.

(n) For controlling vapors of different cargoes at multiple berths while using enriching gas, the highest upper flammable limit or the lowest MOCC of the cargo or enriching gas, whichever is applicable, is used to determine the analyzer alarm and shutdown setpoints. Alternatively, the mixture's upper flammable limit or MOCC, which may be determined by using Coast Guard guidance available at <http://homeport.uscg.mil>, may be used.

(o) For controlling vapors of inert and non-inert cargoes at multiple berths while using enriching gas—

(1) The lowest MOCC of the cargo or enriching gas is used to determine the analyzer alarm and shutdown setpoints at all berths. Alternatively, the mixture's MOCC, which may be determined using Coast Guard guidance available at <http://homeport.uscg.mil>, may be used; or

(2) A base loading method meeting the requirements of paragraph (m) of this section is used for all berths.

§ 154.2108 Vapor-moving devices.

(a) Paragraphs (b) and (e) of this section apply only to facilities collecting vapors of flammable, combustible, or non-high flash point liquid cargoes.

(b) Each inlet and outlet to a vapor-moving device that handles vapor that has not been inerted, enriched, or diluted in accordance with 33 CFR 154.2107 must be fitted with a detonation arrester; however, the outlet detonation arrester may be omitted if the vapor-moving device is within 50 times the pipe's diameter of the detonation arrester required by 33 CFR 154.2109(a).

(c) If the vapor is handled by a reciprocating or screw-type compressor in the vapor collection system, the compressor must be installed with indicators and audible and visible alarms to warn against the following conditions:

- (1) Excessive gas temperature at the compressor outlet;
- (2) Excessive cooling water temperature;
- (3) Excessive vibration;
- (4) Low lube oil level;
- (5) Low lube oil pressure; and
- (6) Excessive shaft bearing temperature.

(d) If the vapor is handled by a liquid ring-type compressor in the vapor collection system, it must be installed with indicators and audible and visible alarms to warn against the following conditions:

- (1) Low level of liquid sealing medium;
- (2) Lack of flow of the liquid sealing medium;
- (3) Excessive temperature of the liquid sealing medium;
- (4) Low lube oil level;
- (5) Low lube oil pressure, if pressurized lubricating system; and
- (6) Excessive shaft bearing temperature.

(e) If the vapor is handled by a centrifugal compressor, fan, or lobe blower in the vapor collection system, construction of the blades or housing must be one of the following:

- (1) Blades or housing of nonmetallic construction;
- (2) Blades and housing of nonferrous material;
- (3) Blades and housing of corrosion resistant steel;

(4) Ferrous blades and housing with one-half inch or more design tip clearance;

(5) Nonferrous blades and ferrous housing with one-half inch or more design tip clearance; or

(6) Blades of aluminum or magnesium alloy and a ferrous housing with a nonferrous insert sleeve at the periphery of the impeller.

§ 154.2109 Vapor recovery and vapor destruction units.

Paragraphs (a), (b), and (e) of this section apply only to facilities collecting vapors of flammable, combustible, or non-high flash point liquid cargoes.

(a) The inlet to a vapor recovery unit that receives vapor that has not been inerted, enriched, or diluted in accordance with 33 CFR 154.2107 must be fitted with a detonation arrester.

(b) The inlet to a vapor destruction unit must—

(1) Have a liquid seal that meets the requirements of paragraph (e) of this section, except as specified by paragraph (b)(3) of this section; and

(2) Have two quick-closing stop valves installed in the vapor line. One of them must be installed upstream of the detonation arrester required by paragraph (c)(2) of this section. The quick-closing stop valves must—

(i) Close within 30 seconds after detection of a condition that requires the closing of these two quick-closing stop valves by a control component required by this subpart for a vapor control system (VCS) with a vapor destruction unit;

(ii) Close automatically if the control signal is lost;

(iii) Have a local valve position indicator or be designed so that the valve position is readily determined from the valve handle or valve stem position; and

(iv) If the valve seat is fitted with resilient material, be a Category A valve as defined by 46 CFR 56.20-15 and not allow appreciable leakage when the resilient material is damaged or destroyed; and

(3) Instead of a liquid seal as required by paragraph (b)(1) of this section, have the following:

(i) An anti-flashback burner accepted by the Commandant and installed at each burner within the vapor destruction unit; and

(ii) A differential pressure sensor that activates the quick-closing stop valves as required by paragraph (b)(2) of this section upon sensing a reverse flow condition.

(c) A vapor destruction unit must—

(1) Not be within 30 meters (98.8 feet) of any tank vessel berth or mooring at the facility;

(2) Have a detonation arrester fitted in the inlet vapor line; and

(3) Activate an alarm that satisfies the requirements of 33 CFR 154.2100(e) and shut down when a flame is detected on the detonation arrester.

(d) When a vapor destruction unit shuts down or has a flame-out condition, the vapor destruction unit control system must—

(1) Activate and close the quick-closing stop valves required by paragraph (b)(2) of this section;

(2) Close the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a); and

(3) Automatically shut down any vapor-moving devices installed in the VCS.

(e) If a liquid seal is installed at the inlet to a vapor destruction unit, then—

(1) The liquid used in the liquid seal must be compatible with the vapors being controlled;

(2) For partially or totally soluble cargoes that can polymerize in solution, there must be an adequate amount of inhibitor in the liquid seal;

(3) The liquid seal must be compatible with the design of the VCS and must not contribute to the flammability of the vapor stream; and

(4) The liquid seal must have a low-level alarm and a low-low level shutdown.

§ 154.2110 Vapor balancing requirements.

Paragraphs (a)(2) and (4), (b), and (c) of this section apply only to facilities transferring vapors of flammable, combustible, or non-high flash point liquid cargoes.

(a) A vapor control system (VCS) that uses a vapor balancing system in

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which cargo vapor is transferred from a vessel cargo tank or facility storage tank through the facility vapor collection system to a facility storage tank or vessel cargo tank must—

(1) Have facility storage tank high-level alarm systems and facility storage tank overfill control systems, independent of the high-level alarm system, arranged to prevent the cargo from entering the vapor return line;

(2) Have a detonation arrester located within the storage tank containment area and a detonation arrester located as close as practicable to the facility vapor connection. The total pipe length between the detonation arrester and the facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source;

(3) Meet the overpressure and over-vacuum protection requirements of 33 CFR 154.2103; and

(4) As an alternative to paragraph (a)(2) of this section, inert cargo systems can meet the requirements of 33 CFR 2105(a)(1).

(b) A vapor balancing system, while in operation to transfer vapor to or from a vessel cargo tank and connected by way of the facility storage tank vent to a facility's main VCS with a vapor destruction unit, must have—

(1) A means to prevent backflow of vapor from the facility's main VCS to the marine vapor line; and

(2) Two fail-safe, quick-closing valves installed in the marine vapor line at the facility storage tank that automatically close when—

(i) Flame is detected on the facility storage tank; or

(ii) The temperature of the facility storage tank's vapor space reaches 177 °C (350 °F) or 70 percent of the vapor's auto-ignition temperature in degrees Celsius, whichever is lower.

(c) Transferring vapor from a non-inerted facility storage tank to a vessel cargo tank that is required to be inerted in accordance with 46 CFR 32.53, 153.500, or Table 151.05, is prohibited.

(d) A vapor balancing system that transfers vapor to a vessel cargo tank

must not use a vapor-moving device to assist vapor transfer or inject inerting, enriching, or diluting gas into the vapor line without approval from the Commandant.

§ 154.2111 Vapor control system connected to a facility's main vapor control system.

(a) When a marine vapor control system (VCS), or a marine vapor collection system, is connected to a facility's main VCS serving other facility processing areas that are not related to tank vessel operations, the marine vapor line, before the point where the marine VCS connects to the facility's main VCS, must be fitted with—

(1) A detonation arrester, unless both the marine VCS and the facility's main VCS only control vapors of cargoes that are non-flammable, non-combustible, or that have high flashpoints;

(2) Two fail-safe, quick closing valves, one on each side of any detonation arrester required by paragraph (a)(1) of this section, which automatically close when—

(i) A flame is detected on the detonation arrester;

(ii) The facility's marine VCS is not in operation; or

(iii) Vapor back flow to the marine vapor line is detected; and

(3) A means to prevent backflow of vapors to the marine vapor line.

(b) Vapors from facility processing areas unrelated to tank vessel operations must not enter the vapor line of a marine VCS before the devices required by paragraph (a) of this section.

(c) Except as specified by paragraph (d) of this section, a facility that wants to connect a facility vapor line, which collects vapor from other facility processing areas that are not related to tank vessel operations, to a marine VCS before the devices required by 33 CFR 154.2109(b)(1) and (2) and (c)(2), must receive approval in writing from the Commandant.

(d) A facility may connect a facility vapor line, which collects vapor from other facility processing areas that are not related to tank vessel operations, to a marine vapor line downstream of the devices required by 33 CFR 154.2109(b)(1) and (2) and (c)(2) to share the marine vapor destruction unit.

§ 154.2112 Vapors with potential to polymerize or freeze—Special requirements.

(a) A vapor control system (VCS) that controls vapors with the potential to polymerize at a normal ambient condition must—

(1) Be designed to prevent condensation of monomer vapor. Methods such as heat tracing and insulation are permitted if they do not result in an increased risk of polymerization;

(2) Be designed so that polymerization can be detected. Any points suspected of being sites for potential polymerization buildup must be equipped with inspection openings; and

(3) Include devices to measure the pressure drop across detonation arresters due to polymerization. The devices should activate an alarm on high pressure drop to warn of polymerization. Any device used for this purpose, including differential pressure monitors, must not have the capability of transmitting a detonation across the detonation arrester.

(b) A VCS that controls cargo vapors that potentially freeze at ambient temperature must have a design that prevents the freezing of vapors or condensate at ambient temperature or that detects and removes the liquid condensate and solids to prevent accumulation.

§ 154.2113 Alkylene oxides—Special requirements.

A vapor control system (VCS) that controls vapors of an alkylene oxide, except for carriage under 46 CFR part 151 (listed in Table 151.05 with “Pressure” entry in the “Cargo identification, Pressure, b” column), must comply with paragraphs (a) and (b) of this section.

(a)(1) The VCS’s equipment, hoses, piping, and all piping components, including valves, flanges, and fittings, must be of a type and constructed out of materials suitable for use with alkylene oxide;

(2) The VCS used for collecting an alkylene oxide vapor must not be used for collecting other vapors and must be separated from any other VCS, except as specified by paragraph (b) of this section; and

(b) The VCS must be adequately cleaned in accordance with 33 CFR 154.2150(p) and either recertified by a certifying entity or approved by a marine chemist if—

(1) The VCS is used to control other vapors; or

(2) The VCS is returned to alkylene oxide service after being used to control other cargo vapors.

TRANSFER FACILITIES—OPERATIONS

§ 154.2150 General requirements.

(a) No transfer operation using a vapor control system (VCS) may be conducted unless the facility operator has a copy of the facility operations manual, with the VCS addendum, marked by the local Coast Guard Captain of the Port (COTP) as required by 33 CFR 154.325(d).

(b) Personnel in charge of a facility must ensure that—

(1) The facility controls vapor only from cargoes that are properly authorized for vapor control in the facility’s certification letter;

(2) The facility transfers vapor only to or from a vessel that has its certificate of inspection or certificate of compliance endorsed in accordance with 46 CFR 39.1013 or 46 CFR 39.1015 for each cargo intended for transfer; and

(3) If the vessel tanks to be vapor controlled contain vapor from previous cargo transfers other than the cargo or cargoes intended for transfer, the facility and vessel must be authorized to control the additional vapor from the previous cargo transfers. Any oxygen or hydrocarbon analyzer alarm and shutdown setpoints must be set to accommodate all of the cargo vapors.

(c) The facility personnel in charge must ensure that safety system testing is conducted as follows:

(1) Pressure sensors, alarms, and automatic shutdown systems required by 33 CFR 154.2103, 154.2107, and 154.2110, except as exempted by paragraph (c)(2) or specified by paragraph (c)(3) of this section, must be tested by applying altering test pressures at the sensors not more than 24 hours before each transfer;

(2) The pressure sensors required by 33 CFR 154.2103 may meet the requirements of the test program contained in

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33 CFR 154.2180 and 33 CFR 154.2181 instead of the current program, which mandates tests within 24 hours before each transfer as required by paragraph (c)(1) of this section;

(3) Visible and audible alarm indicators must be tested not more than 24 hours before each transfer;

(4) The analyzers, except for flammability analyzers, required by 33 CFR 154.2105, 154.2107, and 154.2110, except as exempted by paragraph (c)(5) of this section, must be checked for calibration response by using a zero gas and a span gas not more than 24 hours before each transfer;

(5) The analyzers required by 33 CFR 154.2105, 154.2107, and 154.2110 may be checked for calibration response by use of a zero gas and a span gas as defined by the test program contained in 33 CFR 154.2180 and 33 CFR 154.2181, and comply with the minimum requirements as defined in 33 CFR 154.2180 and 33 CFR 154.2181, instead of the test required by paragraph (c)(4) of this section; and

(6) The vacuum and pressure relief valves required by 33 CFR 154.2103 must be manually checked per manufacturers' instructions to verify that the valves unseat easily and then reset to the closed position without constraint. Any required flame screens or flame arresters must also be visually checked to ensure that they are not damaged.

(d) The proper position of all valves in the vapor line between the vessel's tanks and the facility vapor collection system must be verified before the start of the transfer operation.

(e) A tank barge overfill control system that meets the requirements of 46 CFR 39.2009(a)(2) must—

(1) Not be connected to an overfill sensor circuit that exceeds the system's rated inductance and capacitance; and

(2) Be tested for proper operation after connection is made with the vessel by simulating liquid high level and overfill at each tank.

(f) When receiving vapor from a vessel with cargo tanks that are required to be inerted in accordance with 46 CFR 32.53, 46 CFR 153.500, or 46 CFR Table 151.05, the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a) must not be opened

until the pressure at the facility vapor connection, downstream of the facility vapor connection, exceeds 0.2 pounds per square inch gauge (psig).

(g) The initial cargo transfer rate must not exceed the rate agreed upon at the pre-transfer conference and 46 CFR 39.3001(g).

(h) The cargo transfer rate must not exceed the maximum allowable transfer rate as determined by the lesser of the following:

(1) A transfer rate corresponding to the maximum vapor processing rate for the VCS, as specified in the facility operations manual; or

(2) The vessel's maximum transfer rate in accordance with 46 CFR 39.3001(d).

(i) While transferring cargo to a vessel connected to a VCS, compressed air or gas may be used to clear cargo hoses and loading arms, but must not be used to clear cargo lines. However, compressed inert gas such as nitrogen can be used to clear cargo lines if a pigging system that meets 33 CFR 154.2104 is provided.

(j) If a pigging system is used to clear cargo lines to the tank vessel while the vessel is connected to the facility VCS, the following operational requirements apply:

(1) The VCS must be in operation, with all of the high-pressure alarms and shutdowns required by 33 CFR 154.2103 active, before and during pigging operations;

(2) Personnel performing the pigging operation must be adequately trained on the specific pigging system being used. Accurate written procedures that address event sequence, equipment, safety precautions, and overpressurization hazards must be made available to all personnel involved in the pigging operations;

(3) Pigging procedures must be reviewed by both the vessel and facility personnel in charge as part of the pre-transfer conference. Topics of discussion during the pre-transfer conference must include, but need not be limited to—

- (i) Event sequence;
- (ii) Equipment;
- (iii) Safety precautions;
- (iv) Overpressurization hazards;
- (v) Personnel roles;

- (vi) Gas volumetric flow rates;
- (vii) Gas pressures;
- (viii) Volume of residual cargo in the line;
- (ix) Amount of ullage space that is available for line displacement and connections;
- (x) Valve alignment;
- (xi) Units of measure;
- (xii) Terminology; and
- (xiii) Anticipated duration of the evolution;

(4) The pig must be inspected to ensure that it is of sufficient durability and condition; be of an appropriate size, type, and construction for the intended operation; and be inspected for defects before each use and replaced if necessary;

(5) Personnel performing pigging operations must monitor pig movement at all times. The facility and vessel manifold valves must be closed immediately after the pig reaches the pig-receiving device; and

(6) If the pigging system contains pressure-sensing, relieving, or alarming components in addition to those required by 33 CFR 154.2103, the components must be periodically tested in accordance with paragraphs (c) and (q) of this section.

(k) If one or more analyzers required by 33 CFR 154.2107(d) or (e) or 154.2110 become inoperable during a transfer operation, the operation may continue, provided that at least one analyzer remains operational; however, no further transfer operations may start until all inoperable analyzers are replaced or repaired.

(l) Whenever a condition results in a shutdown of the VCS, the emergency shutdown system required by 33 CFR 154.550 must be automatically activated to terminate cargo loading into tanks which are being vapor controlled.

(m) If it is suspected that a flare in the VCS has had a flashback, or if a flame is detected on a detonation arrester required by 33 CFR 154.2109(c)(2), the transfer operation must stop and cannot restart until that detonation arrester and any quick-closing stop valves downstream of the detonation arrester are inspected and found to be in satisfactory condition.

(n) Before each transfer operation, the freezing point of each cargo must be determined. If there is a possibility that the ambient air temperature during transfer operations will be at or below the freezing point of the cargo, adequate precautions must be taken to prevent freezing of vapor or condensate, or to detect and remove the frozen liquid and condensation to prevent accumulation.

(o) Before each transfer operation, the cargo vapor must be evaluated to determine its potential to polymerize, and adequate precautions must be taken to prevent and detect polymerization of the cargo vapors.

(p) Mixing of incompatible vapors is prohibited. The VCS piping, equipment, hoses, valves, and arresters must be purged between vapor control operations that involve incompatible chemical vapors in accordance with the following:

(1) Chemical compatibility must be determined by using the procedures contained in 46 CFR part 150;

(2) Purge gas must be an inert gas, air, or enriching gas, and must be adequate to reduce the level of residual vapor to a level at which reaction with the subsequent vapor cannot occur; and

(3) The required duration of purge time must be calculated and approved by the certifying entity during the certification or recertification.

(q) After each transfer operation, the VCS piping, equipment, hoses, valves, and arresters must be purged with at least two-system volume exchanges of non-reactive gas or air so the VCS is left with a safe condition.

(r) VCS equipment and instrumentation must be tested in compliance with 33 CFR 156.170(g) or (i), with the COTP or designated representative invited to observe these tests. The test procedure and a checklist must be approved by the certifying entity during the initial certification of the system and incorporated into the facility operations manual.

(s) A transfer operation that includes collection of vapor emitted to or from a vessel's cargo tanks must meet the transfer requirements of 33 CFR 156.120(aa), and a declaration of inspection meeting the requirements of 33

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CFR 156.150 must be completed before each transfer.

ALTERNATIVE ANALYZER AND PRESSURE SENSOR RELIABILITY TESTING

§ 154.2180 Alternative testing program—Generally.

(a) As an alternative to complying with the vapor control system (VCS) analyzer and pressure sensor safety testing requirements provided by 33 CFR 154.2150(c) and 33 CFR 154.2250(c), the facility person in charge may administer a reliability assurance test program in accordance with this section and 33 CFR 154.2181.

(b) As used in this section—

(1) *Calibration drift* or *CD* means the difference in the analyzer output readings from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place;

(2) *Calibration error* or *CE* means the difference between the gas concentration exhibited by the gas analyzer and the known concentration of the cylinder gas;

(3) *Response time* or *RT* means the time interval between the start of a step change in the system input (e.g., change of calibration gas) and the time when the data recording system displays 95 percent of the final stable value; and

(4) *Sampling system bias* or *SSB* means the difference between the gas concentrations indicated by the measurement system when a known cylinder gas is introduced at or near the sampling probe and when the same gas is introduced directly to the analyzer.

(c) All analyzers used in a VCS must be tested for safety system functions, CE, CD, RT, and SSB, in accordance with 33 CFR 154.2181.

(d) All pressure sensors/switches used in a VCS must be tested for safety system functions, CE and CD, in accordance with 33 CFR 154.2181.

(e) The facility person in charge must ensure the following:

(1) Calibration of instrumentation using standard procedures provided by the manufacturer or service provider;

(2) Monitoring of all interlocks, alarms, and recording devices for prop-

er operation while instrumentation is being calibrated;

(3) Use of a certified gas standard that is within plus or minus two (2) percent of its certified concentration to calibrate the analyzers; and

(4) Use of a certified secondary standard that is standardized against a primary standard to calibrate the pressure sensors/switches.

(f) Upon failing any test under 33 CFR 154.2181, the facility person in charge must ensure that all monthly and quarterly tests, including CE, CD, RT, and SSB, are conducted; and until all quarterly tests are completed, the person in charge must ensure that the vapor control alarms and automatic shutdown system are tested no more than 24 hours prior to any transfer or tank barge cleaning operation.

(g) Analyzers required by 33 CFR 154.2105(a) and (j) and 154.2107(d) and (e) must be checked for calibration using a zero gas and a span gas.

(h) The facility operator must maintain and make available upon the request of the Commandant and the certifying entity that certifies the VCS the following reliability assurance test program documents for two years:

- (1) All test procedures;
- (2) The dates of all tests, type of tests made, and who conducted the tests;
- (3) Results of the tests, including the “as found” and “as left” conditions; and
- (4) A record of the date and time of repairs made.

§ 154.2181 Alternative testing program—Test requirements.

(a) The safety system function test required by 33 CFR 154.2180 must be performed once every two weeks and test for the proper operation and interaction of the analyzer or pressure sensor/switch with shutdown interlocks, and audible and visible alarm devices.

(b) The calibration error (CE) test required by 33 CFR 154.2180 must be performed once every month and documented as shown in Forms 154.2181(b)(2) and 154.2181(b)(3) of this section, to document the accuracy and linearity of the monitoring equipment for the entire measurement range.

(1) The CE test must expose the measurement system, including all

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monitoring components (e.g., sample lines, filters, scrubbers, conditioners, and as much of the probe as practicable), to the calibration gases, introduced through an injection port located so as to allow a check of the entire measurement system when calibration gases are introduced;

(2) The CE test must check the calibrated range of each analyzer using a lower (zero) and upper (span) reference gas standard. Three measurements must be taken against each standard

and recorded as shown in Form 154.2181(b)(2) of this section, with the average of the three values in each case then used to calculate the CE according to this equation (where CE = percentage calibration error based upon span of the instrument, R = reference value of zero or high-level calibration gas introduced into the monitoring system, A = actual monitoring system response to the calibration gas, and S = span of the instrument):

$$CE = \frac{|R - A|}{S} \times 100$$

FORM 154.2181(B)(2): CALIBRATION ERROR DETERMINATION.

	Calibration value	Monitor response	Difference	
			Zero	Span
1-Zero				
1-Span				
2-Zero				
2-Span				
3-Zero				
3-Span				
Mean Difference =				
Calibration Error =			%	%

(3) The CE test must check each pressure sensor/switch for upscale (activate) and downscale (deactivate) hysteresis around the sensor/switch set pressure. The calibration error must be calculated and recorded as shown in Form 154.2181(b)(3) of this section. Test the pressure sensor/switch three times and record the desired setting and the

as-found set pressure. Calculate and record the difference of the two settings. Calculate the error percentage using this equation (where CE = percentage calibration error based upon span of the instrument, R = reference setting of the instrument, A = actual response as recorded on the test instrument, and S = span of the instrument):

$$CE = \frac{|R - A|}{S} \times 100$$

Record sensor “as-left” setting only if an adjustment is made.

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Form 154.2181(b)(3): Switch calibration error.

QUALITY ASSURANCE DATA SHEET SWITCH DATA RECORD					
DATE. _____		F.I. NO. _____			
MANUFACTURER _____					
MODEL NO. _____		SERIAL NO. _____			
SERVICE _____					
CR = CLOSSES ON RISE			OR = OPENS ON RISE		
CF = CLOSSES ON FALL			OF = OPENS ON FALL		
TEST EQUIPMENT		MODEL NO.		SERIAL NO.	
FUNCTION	DESIRED	AS FOUND	DIFFERENCE	ERROR %	AS LEFT
Test #1					
Set					
Reset					
Test #2					
Set					
Reset					
Test #3					
Set					
Reset					
SPEC NO. _____		TEST PERFORMED BY: _____			
DATE: _____		ACCEPTED BY: _____			
REMARKS:					

(c) The calibration drift (CD) test required by 33 CFR 154.2180 must be performed once every quarter and documented as shown in Form 154.2181(c)(3) of this section, to verify the ability of the instrument to conform to the established calibration.

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(1) The CD measurement must be conducted once daily for 7 consecutive days without making any adjustments to the instruments.

(2) Conduct the CD test at zero level (between 0 and 20 percent of the instrument span) and at high level (between

75 and 95 percent of the instrument span).

(3) Calculate and record the CD for 7 consecutive days using the equations in paragraphs (b)(2) and (3) of this section and Form 154.2181(c)(3) of this section.

FORM 154.2181(C)(3): CALIBRATION DRIFT DETERMINATION.

Day	Day/time	Reference value (RV)	Monitor value	Difference	Percent of RV
Low-Level:					
High-Level:					

(d) The response time (RT) test required by 33 CFR 154.2180 must be performed once every quarter and documented as shown in Form 154.2181(d) of this section, to determine the RT which is the largest average response time in the upscale or downscale direction.

(1) For systems that normally operate below 20 percent of calibrated range, only a span (upscale) test is required.

(2) Record the span (upscale) value, zero (downscale) cylinder gas value, and stable, initial process-measured variable value.

(3) Determine the step change, which is equal to the average difference between the initial process-measured

variable value and the average final stable cylinder gas-measured value.

(4) To determine both upscale and downscale step change intervals—

(i) Inject span (or zero) cylinder gas into the sample system as close to the sample probe as possible. Existing systems that inject the gas at the analyzer box do not need to be modified. However, the gas transit time between the analyzer box and the sample probe must be taken into account;

(ii) Allow the analyzer to stabilize and record the stabilized value. A stable reading is achieved when the concentration reading deviates less than 6 percent from the measured average

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concentration in 6 minutes or if it deviates less than 2 percent of the monitor's span value in 1 minute;

(iii) Stop the span (or zero) gas flow, allow the monitor to stabilize back to the measured variable value, and record the stabilized value; and

(iv) Repeat this procedure a total of three times and subtract the average final monitor reading from the average starting monitor value to determine the average upscale (or downscale) step change.

(5) Determine the response time, which is equal to the elapsed time at which 95 percent of the step change occurred.

(i) To find this value, take 5 percent of the average step change value and subtract the result from the cylinder

gas analyzed value as shown in the following equation:

$$95\% \text{ step change value} = \text{cylinder gas value} - (0.05 \times \text{avg. step change})$$

(ii) Inject span (or zero) cylinder gas into the sample system as close to the sample probe as possible, and measure the time it takes to reach the 95 percent step change value.

(iii) Repeat the previous step (paragraph (d)(5)(ii) of this section) a total of three times each with span and zero cylinder gas to determine average upscale and downscale response times.

(iv) Compare the response times achieved for the upscale and downscale tests. The longer of these two times equals the response time for the analyzer.

Form 154.2181(d): Response time.

<p>Date of test _____</p> <p>Component/system ID#: _____</p> <p>Analyzer type _____</p> <p>Serial Number _____</p> <p>High-level gas concentration: ___ ppm / %</p> <p>Zero-level gas concentration: ___ ppm / %</p> <p>Analyzer span setting: ___ ppm / %</p> <p>Upscale:</p> <p>Stable starting monitor value: ____, ____, ____;</p> <p>Avg. ___ ppm / %</p> <p>Stable ending monitor reading: ____, ____, ____;</p> <p>Avg. ___ ppm / %</p> <p>Step change interval: ___ ppm; 95%</p> <p>Step change value: ___ ppm / %</p> <p>Elapsed time: ____, ____, ____; Avg. _____ seconds</p> <p>Downscale:</p> <p>Stable starting monitor value: ____, ____, ____;</p> <p>Avg. ___ ppm / %</p> <p>Stable ending monitor reading: ____, ____, ____;</p> <p>Avg. ___ ppm / %</p> <p>Step change interval: ___ ppm; 95%</p> <p>Step change value: ___ ppm / %</p> <p>Elapsed time: ____, ____, ____;</p> <p>Avg. ___ seconds</p> <p>System response time = ___ seconds</p>

(e) The sample system bias (SSB) test required by 33 CFR 154.2180 must be performed once every quarter and documented, to establish that the system has no additional influence on the measurement being made by the analyzer.

(1) Conduct a close CE test in accordance with paragraph (b) of this section, by injecting calibration gas as close as possible to the analyzer, eliminating as much of the sample system components as possible, while still simulating the normal source operating conditions.

(2) If system integrity is maintained, and it has not become contaminated, the difference between the close and standard CE tests should be the same.

(f) For CE and CD tests, analyzers and pressure sensors must meet the following minimum compliance requirements:

(1) Oxygen analyzers must not deviate from the reference value of the zero- or high-level calibration gas by more than 0.5 percent of full scale;

(2) Total hydrocarbon analyzers must not deviate from the reference value of the zero- or high-level calibration gas by more than 1 percent of full scale; and

(3) Pressure sensors/switches must not deviate from the reference value of the zero- or high-level calibration gas by more than 1.5 percent of full range.

(g) For RT tests, each oxygen or hydrocarbon analyzer must respond, in less than 1 minute, to 95 percent of the final stable value of a test span gas.

(h) For SSB tests, the analyzer system bias must be less than 5 percent of the average difference between the standard CE test and the close CE test, divided by the individual analyzer span.

TANK BARGE CLEANING FACILITIES—
VCS DESIGN AND INSTALLATION

§ 154.2200 Applicable transfer facility design and installation requirements.

A tank barge cleaning facility's (TBCF's) vapor control system (VCS) must meet the following design and installation requirements of this subpart for a transfer facility's VCS:

(a) 33 CFR 154.2100(b), (c), (f), (g), (i), (j), and (k): general design and installation requirements;

(b) 33 CFR 154.2102: facility requirements for vessel liquid overflow protection, if a TBCF receives vapor from a tank barge that is required by 46 CFR 39.6001(f)(3) to be equipped with a liquid overflow protection arrangement and meet 46 CFR 39.2009;

(c) 33 CFR 154.2106: detonation arrester installation;

(d) 33 CFR 154.2107: inerting, enriching, and diluting systems;

(e) 33 CFR 154.2108: vapor-moving devices;

(f) 33 CFR 154.2109: vapor recovery and vapor destruction units;

(g) 33 CFR 154.2111: VCS connected to a facility's main VCS;

(h) 33 CFR 154.2112: special requirements for vapors with the potential to polymerize or freeze; and

(i) 33 CFR 154.2113: special requirements for alkylene oxides.

§ 154.2201 Vapor control system—general requirements.

(a) Vapor control system (VCS) design and installation must eliminate potential overpressure and vacuum hazards, sources of ignition, and mechanical damage to the maximum practicable extent. Each remaining hazard source that is not eliminated must be specifically addressed in the protection system design and system operational requirements.

(b) Any pressure, flow, or concentration indication required by this part must provide a remote indicator on the facility where the VCS is controlled, unless the local indicator is clearly visible and readable from the operator's normal position at the VCS control station.

(c) Any condition requiring an alarm as specified in this part must activate an audible and visible alarm where the VCS is controlled.

(d) A mechanism must be developed and used to eliminate any liquid from the VCS.

(e) A liquid knockout vessel must be installed between the facility vapor connection and any vapor-moving device in systems that have the potential for two-phase (vapor/liquid) flow from the barge or the potential for liquid

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condensate to form as a result of the enrichment process. The liquid knockout vessel must have—

(1) A means to indicate the level of liquid in the device;

(2) A high liquid level sensor that activates an alarm that satisfies the requirements of 33 CFR 154.2100(e); and

(3) A high-high liquid level sensor that closes the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a) and shuts down any vapor-moving device before liquid is carried over to the vapor-moving device. One sensor with two stages may be used to meet this requirement as well as paragraph (e)(2) of this section.

§ 154.2202 Vapor line connections.

(a) 33 CFR 154.2101(a), (e), and (g) apply to a tank barge cleaning facility's (TBCF's) vapor control system (VCS).

(b) The remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a) must be located upstream of the liquid knockout vessel required by 33 CFR 154.2201(e).

(c) A fluid displacement system must have a remotely operated shutoff valve installed in the fluid injection supply line between the point where the inert gas or other medium is generated and the fluid injection connection. The valve must comply with 33 CFR 154.2101(a)(1) through (6).

(d) Each hose used for transferring vapors must—

(1) Have a design burst pressure of at least 25 pounds per square inch gauge (psig);

(2) Have a maximum allowable working pressure (MAWP) no less than 5 psig;

(3) Be capable of withstanding at least the maximum vacuum rating of the vapor-moving device without collapsing or constricting;

(4) Be electrically continuous, with a maximum resistance of 10,000 ohms;

(5) Have flanges with a bolthole arrangement complying with the requirements for Class 150 ANSI B16.5 flanges (incorporated by reference, see 33 CFR 154.106);

(6) Be abrasion and kinking resistant; and

(7) Be compatible with vapors being transferred.

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(e) Fixed vapor collection arms must meet the requirements of paragraph (d) of this section.

§ 154.2203 Facility requirements for barge vapor overpressure and vacuum protection.

In this section, the requirements of having a flame arrester or a flame screen at the opening of a pressure relief valve or a vacuum relief valve apply only to facilities collecting vapors of flammable, combustible, or non-high flash point liquid cargoes.

(a) A facility vapor collection system must have a capacity for collecting cleaning facility vapors at a rate of no less than 1.1 times the facility's maximum allowable gas-freeing rate, plus any inerting, diluting, or enriching gas that may be added to the system.

(b) A facility vapor control system (VCS) must be designed to prevent the pressure in a vessel's cargo tanks from going below 80 percent of the highest setting of any of the barge's vacuum relief valves or exceeding 80 percent of the lowest setting of any of the barge's pressure relief valves. The VCS must be capable of maintaining the pressure in the barge's cargo tanks within this range at any gas-freeing rate less than or equal to the maximum gas-freeing rate determined by the requirements in 46 CFR 39.6007(c).

(c) A fluid displacement system must provide a pressure-sensing device that activates an alarm that satisfies the requirements of 33 CFR 154.2100(e) when the pressure at the fluid injection connection exceeds either the pressure corresponding to the upper pressure determined in paragraph (b) of this section or a lower pressure agreed upon by the facility and barge persons in charge. The pressure-sensing device must be located in the fluid displacement system's piping downstream of any devices that could potentially isolate the barge's vapor collection system from the pressure-sensing device. The pressure measured by the sensing device must be corrected for pressure drops across any barge piping, hoses, or arms that are used to inject the fluid.

(d) A fluid displacement system must provide a pressure-sensing device that is independent of the device required by paragraph (c) of this section. This

pressure-sensing device must activate the fluid displacement system emergency shutdown and close the remotely operated cargo vapor shutoff valve required by 33 CFR 154.2101(a). It must also close the remotely operated shutoff valve required by 33 CFR 154.2202(c) when the pressure at the fluid injection connection reaches a corresponding 90 percent of the lowest setting of any pressure relief valve on the barge. The pressure-sensing device must be located in the fluid displacement system's piping downstream of any device that could potentially isolate the barge's VCS from the pressure-sensing device. The pressure measured by the sensing device must be corrected for pressure drops across any barge piping, hoses, or arms that are used to inject the fluid.

(e) If a vapor-moving device capable of drawing more than 0.5 pounds per square inch gauge (psig) vacuum is used to draw vapor, air, inert gas, or other medium from the barge, a vacuum relief valve must be installed on the facility's fixed vapor collection system piping between the facility vapor connection and the vapor-moving device. The vacuum relief valve must—

(1) Relieve at a pressure such that the pressure at the facility vapor connection is maintained at or above 14.2 pounds per square inch absolute (psia) (-0.5 psig);

(2) Have a relieving capacity equal to or greater than the maximum capacity of the vapor-moving device;

(3) Have a flame arrester or flame screen fitted at the vacuum relief opening;

(4) Have been tested for relieving capacity in accordance with paragraph 1.5.1.3 of API 2000 (incorporated by reference, see 33 CFR 154.106), with a flame arrester or flame screen fitted; and

(5) Be constructed of materials compatible with the vapors being gas-freed.

(f) The vacuum relief valve requirements of paragraph (e) of this section may include a valve to isolate it from the facility vapor collection piping, provided—

(1) The isolation valve must be interlocked with any vapor-moving device such that the vapor-moving device cannot activate unless the isolation

valve is in the full open position (*i.e.*, the vacuum relief valve is not isolated); and

(2) The isolation valve can only be closed after the facility person in charge has acknowledged that the hatch opening required by 33 CFR 154.2250(i) is open and secured.

(g) If a vapor-moving device capable of drawing more than 0.5 psig vacuum is used to draw vapor, air, inert gas, or other medium from the barge, the facility must install portable, intrinsically safe, pressure-sensing devices on any cargo tank, or on the common vapor header, at the connection required by 46 CFR 39.6003(b) before any cleaning operation begins on the tank. A pressure-sensing device must be provided that—

(1) Activates an alarm that satisfies 33 CFR 154.2100(e) when the pressure in the cargo tank being cleaned falls below 80 percent of the highest setting of any of the barge's vacuum relief valves, or a higher pressure agreed upon by the facility and barge persons in charge; and

(2) Activates the emergency shutdown system for the vapor-moving device and closes the remotely operated cargo vapor shutoff valve described in 33 CFR 154.2101(a) when the pressure in the cargo tank being cleaned falls below 90 percent of the highest setting of any of the barge's vacuum relief valves, or a higher pressure agreed upon by the facility and barge persons in charge. This pressure-sensing device must be independent of the device used to activate an alarm required by paragraph (g)(1) of this section.

(h) The pressure-sensing devices required by paragraph (g) of this section must—

(1) Have suitable means, such as approved intrinsic safety barriers that are able to accept passive devices, so that the under-pressure alarm circuits of the barge side of the under-pressure control system, including cabling, normally closed switches, and pin and sleeve connectors, are intrinsically safe;

(2) Be connected to the under-pressure alarm system by a four-wire, 16-ampere shielded flexible cable; and

(3) Have cable shielding grounded to the under-pressure alarm system.

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(i) A pressure-indicating device must be provided within 6 meters (19.7 feet) of the facility vapor connection which displays the pressure in the vapor collection line upstream of any isolation valve and any devices, such as strainers, that could cause a blockage in the vapor line.

(j) A fluid displacement system must include a pressure-indicating device that displays the pressure in the fluid displacement system injection line. This device must be within 6 meters (19.7 feet) of the fluid injection connection.

(k) If a fluid displacement system used to inject inert gas or another medium into the cargo tank of a barge being gas-freed is capable of producing a pressure greater than 2 psig, a pressure relief valve must be installed in the fluid displacement system injection line between the fluid injection source and the fluid injection connection that—

(1) Relieves at a predetermined pressure such that the pressure in the fluid displacement system at the fluid injection connection does not exceed 1.5 psig;

(2) Has a relieving capacity equal to or greater than the maximum volumetric flow capacity of the fluid displacement system;

(3) Has a flame screen or flame arrester fitted at the relief opening; and

(4) Has been tested for relieving capacity in accordance with paragraph 1.5.1.3 of API 2000, when fitted with a flame screen or flame arrester.

(1) When using the fluid displacement system, if the pressure in the facility's fixed vapor collection system can exceed 2 psig during a malfunction in an inerting, enriching, or diluting system, a pressure relief valve must—

(1) Be installed between the point where inerting, enriching, or diluting gas is added to the facility's fixed vapor collection system piping and the facility vapor connection;

(2) Relieve at a predetermined pressure such that the pressure at the facility vapor connection does not exceed 1.5 psig;

(3) Have a relieving capacity equal to or greater than the maximum capacity of the facility's inerting, enriching, or diluting gas source;

(4) Have a flame screen or flame arrester fitted at the relief opening;

(5) Have been tested for relieving capacity in accordance with paragraph 1.5.1.3 of API 2000, when fitted with a flame screen or flame arrester; and

(6) Be constructed of materials compatible with the vapors being gas-freed.

(m) For fluid displacement systems, the fluid injection connection must be electrically insulated from the fluid injection source in accordance with OCIMF ISGOTT section 17.5 (incorporated by reference, see 33 CFR 154.106).

(n) If the pressure relief valve is not designed with a minimum vapor discharge velocity of 30 meters (98.4 feet) per second, the relieving capacity test required by paragraphs (k)(4) and (l)(5) of this section must be carried out with a flame screen or flame arrester fitted at the discharge opening.

(o) A pressure indicating device must be provided by the facility for installation at the connection required by 46 CFR 39.6003(b).

§ 154.2204 Fire, explosion, and detonation protection.

This section applies to tank barge cleaning facilities (TBCFs) collecting vapors of flammable, combustible, or non-high flash point liquid cargoes.

(a) A vapor control system (VCS) with a single facility vapor connection that processes vapor with a vapor recovery unit must—

(1) Have a detonation arrester located as close as practicable to the facility vapor connection. The total pipe length between the detonation arrester and the facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source; or

(2) Have an inerting, enriching, or diluting system that meets the requirements of 33 CFR 154.2107.

(b) A VCS with a single facility vapor connection that processes vapor with a vapor destruction unit must—

(1) Have a detonation arrester located as close as practicable to the facility vapor connection. The total pipe length between the detonation arrester

and the facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source; and

(2) Have an inerting, enriching, or diluting system that meets the requirements of 33 CFR 154.2107.

(c) A VCS with multiple facility vapor connections that processes vapor with a vapor recovery unit must have a detonation arrester located as close as practicable to each facility vapor connection. The total pipe length between the detonation arrester and each facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source.

(d) A VCS with multiple facility vapor connections that processes vapor with a vapor destruction unit must—

(1) Have a detonation arrester located as close as practicable to each facility vapor connection. The total pipe length between the detonation arrester and each facility vapor connection must not exceed 18 meters (59.1 feet) and the vapor piping between the detonation arrester and the facility vapor connection must be protected from any potential internal or external ignition source; and

(2) Have an inerting, enriching, or diluting system that meets the requirements of 33 CFR 154.2107.

(e) 33 CFR 154.2105(j) applies to a TBCF's VCS.

TANK BARGE CLEANING FACILITIES— OPERATIONS

§ 154.2250 General requirements.

(a) No tank barge cleaning operation using a vapor control system (VCS) may be conducted unless the facility operator has a copy of the facility operations manual, with the VCS addendum, marked by the local Coast Guard Captain of the Port (COTP) as required by 33 CFR 154.325(d).

(b) The facility person in charge must ensure that a facility can receive vapors only from a barge with a VCS that has been approved by the Coast

Guard Marine Safety Center as meeting the requirements of 46 CFR 39.6000.

(c) The facility person in charge must ensure that safety system tests are conducted as follows:

(1) Pressure sensors, alarms, and automatic shutdown systems required by 33 CFR 154.2203, except as exempted by paragraph (c)(2) or as specified by paragraph (c)(3) of this section, must be tested by applying altering test pressures at the sensors not more than 24 hours before each cleaning operation;

(2) The pressure sensors required by 33 CFR 154.2203 may meet the test program in accordance with 33 CFR 154.2180 and 33 CFR 154.2181 instead of the test within 24 hours before each cleaning operation as required by paragraph (c)(1) of this section;

(3) Visible and audible alarm indicators must be tested not more than 24 hours before each cleaning operation;

(4) The analyzers, except for flammability analyzers, required by 33 CFR 154.2105(j) and 154.2107, except as exempted by paragraph (c)(5) of this section, must be checked for calibration response by use of a zero gas and a span gas not more than 24 hours before each cleaning operation;

(5) The analyzers required by 33 CFR 154.2105(j) and 154.2107 may be checked for calibration response by use of a zero gas and a span gas as defined by the test program contained in 33 CFR 154.2180 and 33 CFR 154.2181, and comply with the minimum requirements as defined in 33 CFR 154.2180 and 33 CFR 154.2181, instead of as provided by paragraph (c)(4) of this section; and

(6) The vacuum and pressure relief valves required by 33 CFR 154.2203 must be manually checked per manufacturers' instructions to verify that the valves unseat easily and then reset to the closed position without constraint. Any required flame screens or flame arresters must also be visually checked to ensure that they are not damaged.

(d) The facility person in charge must verify the following before beginning cleaning operations:

(1) Each valve in the vapor collection system between the barge's cargo tank and the facility vapor collection system is correctly positioned to allow the collection of vapors;

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(2) A vapor collection hose or arm is connected to the barge's vapor collection system;

(3) The electrical insulating devices required by 33 CFR 154.2101(g) and 154.2203(m) are installed;

(4) The maximum allowable gas-freeing rate as determined by the lesser of the following:

(i) A gas-freeing rate corresponding to the maximum vapor processing rate for the tank barge cleaning facility's (TBCF's) VCS, as specified in the facility operations manual; or

(ii) The barge's maximum gas-freeing rate determined in accordance with 46 CFR 39.6007(c);

(5) The gas-freeing rate will not exceed the maximum allowable gas-freeing rate as determined in paragraph (d)(4) of this section;

(6) The maximum allowable stripping rate is determined and does not exceed the volumetric capacity of the barge's vacuum relief valve at the valve's setpoint for the cargo tank being stripped;

(7) The barge's maximum and minimum operating pressures;

(8) Each vapor collection hose has no unrepaired or loose covers, kinks, bulges, soft spots, or any other defects that would permit the discharge of vapor through the hose material; and no external gouges, cuts, or slashes that penetrate the first layer of hose reinforcement;

(9) The freezing point of each cargo. If there is a possibility that the ambient air temperature during cleaning operations will be at or below the freezing point of the cargo, adequate precautions have been taken to prevent freezing of vapor or condensate, or to detect and remove the frozen liquid and condensate to prevent accumulation; and

(10) The cargo vapor is evaluated for the potential to polymerize, and adequate precautions have been taken to prevent and detect polymerization of the cargo vapors.

(e) VCS equipment and instrumentation must be tested in compliance with 33 CFR 156.170(g) or (i), with the COTP or designated representative invited to observe these tests. The test procedure and a checklist must be approved by the certifying entity during the initial certification of the system and incor-

porated into the facility operations manual.

(f) If one or more analyzers required by 33 CFR 154.2107(d) or (e) become inoperable during gas-freeing operations, the operation may continue, provided that at least one analyzer remains operational; however, no further gas-freeing operations may be started until all inoperable analyzers are repaired or replaced.

(g) Whenever a condition results in a shutdown of the VCS, the cleaning operations must be immediately terminated. The operation may not resume until the cause of the shutdown has been investigated and corrective action taken.

(h) If it is suspected that a flare in the VCS has had a flashback, or if a flame is detected on a detonation arrester required by 33 CFR 154.2109(c)(2), the cleaning operation must be stopped and may not resume until the detonation arrester and any quick-closing stop valves downstream of the detonation arrester have been inspected and found to be in satisfactory condition.

(i) If a vacuum displacement system is used for gas-freeing, the facility person in charge of the cleaning operation must verify the following items:

(1) The minimum amount of open area for air flow on the barge has been determined so that the pressure in the cargo tank cannot be less than 14.5 pounds per square inch absolute (psia) (-0.2 pounds per square inch gauge (psig)) at the maximum flow capacity of the vapor-moving device;

(2) Any hatch or fitting providing the minimum open area has been secured open so that accidental closure is not possible; and

(3) The hatch and/or fitting must be opened before the pressure in the cargo tank falls below 10 percent of the highest setting of any of the barge's vacuum relief valves.

(j) 33 CFR 154.2150(p) and (q) apply to a TBCF's VCS.

APPENDIX A TO PART 154—GUIDELINES
FOR DETONATION FLAME ARRESTERS

This appendix contains the draft ASTM standard for detonation flame arresters. Devices meeting this standard will be accepted by the Commandant (CG-ENG).

1. *Scope*

1.1 This standard provides the minimum requirements for design, construction, performance and testing of detonation flame arresters.

2. *Intent*

2.1 This standard is intended for detonation flame arresters protecting systems containing vapors of flammable or combustible liquids where vapor temperatures do not exceed 60 °C. For all tests, the test media defined in 14.1.1 can be used except where detonation flame arresters protect systems handling vapors with a maximum experimental safe gap (MESG) below 0.9 millimeters. Detonation flame arresters protecting such systems must be tested with appropriate media (the same vapor or a media having a MESG no greater than the vapor). Various gases and their respective MESG are listed in attachment 1.

2.2 The tests in this standard are intended to qualify detonation flame arresters for all in-line applications independent of piping configuration provided the operating pressure is equal to or less than the maximum operating pressure limit specified in the manufacturer's certification and the diameter of the piping system in which the detonation arrester is to be installed is equal to or less than the piping diameter used in the testing.

NOTE: Detonation flame arresters meeting this standard as Type I devices, which are certified to be effective below 0 °C and which can sustain three stable detonations without being damaged or permanently deformed, also comply with the minimum requirements of the International Maritime Organization, Maritime Safety Committee Circular No. 373 (MSC/Circ. 373/Rev.1).

3. *Applicable Documents*3.1 ASTM Standards¹

A395 Ferritic Ductile Iron Pressure-Retaining Castings For Use At Elevated Temperatures.

F722 Welded Joints for Shipboard Piping Systems

F1155 Standard Practice for Selection and Application of Piping System Materials

3.2 ANSI Standards²

B16.5 Pipe Flanges and Flanged Fittings.

3.3 Other Documents

3.3.1 ASME Boiler and Pressure Vessel Code²

Section VIII, Division 1, Pressure Vessels
Section IX, Welding and Brazing Qualifications.

3.3.2 International Maritime Organization, Maritime Safety Committee³

MSC/Circ. 373/Rev. 1—Revised Standards for the Design, Testing and Locating of Devices to Prevent the Passage of Flame into Cargo Tanks in Tankers.

3.3.3 International Electrotechnical Commission⁴

Publication 79-1—Electrical Apparatus for Explosive Gas Atmospheres.

4. *Terminology*

4.1 $\Delta P/P_0$ —The dimensionless ratio, for any deflagration and detonation test of 14.3, of the maximum pressure increase (the maximum pressure minus the initial pressure), as measured in the piping system on the side of the arrester where ignition begins by the device described in paragraph 14.3.3, to the initial absolute pressure in the piping system. The initial pressure should be greater than or equal to the maximum operating pressure specified in paragraph 11.1.7.

4.2 Deflagration—A combustion wave that propagates subsonically (as measured at the pressure and temperature of the flame front) by the transfer of heat and active chemical species to the unburned gas ahead of the flame front.

4.3 Detonation—A reaction in a combustion wave propagating at sonic or supersonic (as measured at the pressure and temperature of the flame front) velocity. A detonation is stable when it has a velocity equal to the speed of sound in the burnt gas or may be unstable (overdriven) with a higher velocity and pressure.

4.4 Detonation flame arrester—A device which prevents the transmission of a detonation and a deflagration.

4.5 Flame speed—The speed at which a flame propagates along a pipe or other system.

4.6 Flame Passage—The transmission of a flame through a device.

4.7 Gasoline Vapors—A non-leaded petroleum distillate consisting essentially of aliphatic hydrocarbon compounds with a boiling range approximating 65 °C/75 °C.

5. *Classification*

5.1 The two types of detonation flame arresters covered in this specification are classified as follows:

5.1.1 Type I—Detonation flame arresters acceptable for applications where stationary flames may rest on the device.

5.1.2 Type II—Detonation flame arresters acceptable for applications where stationary flames are unlikely to rest on the device, and further methods are provided to prevent flame passage when a stationary flame occurs. One example of "further methods" is a temperature monitor and an automatic shut-off valve.

¹Footnotes appear at the end of this article.

6. Ordering Information

6.1 Orders for detonation flame arresters under this specification shall include the following information as applicable:

- 6.1.1 Type (I or II).
- 6.1.2 Nominal pipe size.
- 6.1.3 Each gas or vapor in the system and the corresponding MESH.
- 6.1.4 Inspection and tests other than specified by this standard.
- 6.1.5 Anticipated ambient air temperature range.
- 6.1.6 Purchaser's inspection requirements (see section 10.1).
- 6.1.7 Description of installation.
- 6.1.8 Materials of construction (see section 7).
- 6.1.9 Maximum flow rate and the maximum design pressure drop for that maximum flow rate.
- 6.1.10 Maximum operating pressure.

7. Materials

7.1 The detonation flame arrester housing, and other parts or bolting used for pressure retention, shall be constructed of materials listed in ASTM F 1155 (incorporated by reference, see §154.106), or section VIII, Division 1 of the ASME Boiler and Pressure Vessel Code. Cast and malleable iron shall not be used; however, ductile cast iron in accordance with ASTM A395 may be used.

7.1.1 Arresters, elements, gaskets, and seals must be made of materials resistant to attack by seawater and the liquids and vapors contained in the system being protected (see section 6.1.3).

7.2 Nonmetallic materials, other than gaskets and seals, shall not be used in the construction of pressure retaining components of the detonation flame arrester.

7.2.1 Nonmetallic gaskets and seals shall be non-combustible and suitable for the service intended.

7.3 Bolting materials, other than that of section 7.1, shall be at least equal to those listed in Table 1 of ANSI B16.5 (incorporated by reference, see 33 CFR 154.106).

7.4 The possibility of galvanic corrosion shall be considered in the selection of materials.

7.5 All other parts shall be constructed of materials suitable for the service intended.

8. Other Requirements

8.1 Detonation flame arrester housings shall be gas tight to prevent the escape of vapors.

8.2 Detonation flame arrester elements shall fit in the housing in a manner that will insure tightness of metal-to-metal contacts in such a way that flame cannot pass between the element and the housing.

8.2.1 The net free area through detonation flame arrester elements shall be at least 1.5 times the cross-sectional area of the arrester inlet.

8.3 Housings, elements, and seal gasket materials shall be capable of withstanding

the maximum and minimum pressures and temperatures to which the device may be exposed under both normal and the specified fire test conditions in section 14, and shall be capable of withstanding the hydrostatic pressure test of section 9.2.3.

8.4 Threaded or flanged pipe connections shall comply with the applicable B16 standards in ASTM F 1155 (incorporated by reference, see §154.106). Welded joints shall comply with ASTM F 722 (incorporated by reference, see §154.106).

8.5 All flat joints of the housing shall be machined true and shall provide for a joint having adequate metal-to-metal contact.

8.6 Where welded construction is used for pressure retaining components, welded joint design details, welding and non-destructive testing shall be in accordance with Section VIII, Division 1, of the ASME Code and ASTM F 722 (incorporated by reference, see §154.106). Welders and weld procedures shall be qualified in accordance with section IX of the ASME Code.

8.7 The design of detonation flame arresters shall allow for ease of inspection and removal of internal elements for replacement, cleaning or repair without removal of the entire device from the system.

8.8 Detonation flame arresters shall allow for efficient drainage of condensate without impairing their efficiency to prevent the passage of flame. The housing may be fitted with one or more drain plugs for this purpose. The design of a drain plug should be such so that by cursory visual inspection it is obvious whether the drain has been left open.

8.9 All fastenings shall be protected against loosening.

8.10 Detonation flame arresters shall be designed and constructed to minimize the effect of fouling under normal operating conditions.

8.11 Detonation flame arresters shall be capable of operating over the full range of ambient air temperatures anticipated.

8.12 Detonation flame arresters shall be of first class workmanship and free from imperfections which may affect their intended purpose.

8.13 Detonation flame arresters shall be tested in accordance with section 9.

9. Tests

9.1 Tests shall be conducted by an independent laboratory capable of performing the tests. The manufacturer, in choosing a laboratory, accepts that it is a qualified independent laboratory by determining that it has (or has access to) the apparatus, facilities, personnel, and calibrated instruments that are necessary to test detonation flame arresters in accordance with this standard.

9.1.1 A test report shall be prepared by the laboratory which shall include:

9.1.1.1 Detailed drawings of the detonation flame arrester and its components (including a parts list identifying the materials of construction).

9.1.1.2 Types of tests conducted and results obtained. This shall include the maximum temperature reached and the length of testing time in section 14.2 in the case of Type II detonation flame arresters.

9.1.1.3 Description of approved attachments (reference 9.2.6).

9.1.1.4 Types of gases or vapors for which the detonation flame arrester is approved.

9.1.1.5 Drawings of the test rig.

9.1.1.6 Record of all markings found on the tested detonation flame arrester.

9.1.1.7 A report number.

9.2 One of each model Type I and Type II detonation flame arrester shall be tested. Where approval of more than one size of a detonation flame arrester model is desired, only the largest and smallest sizes need be tested provided it is demonstrated by calculation and/or other testing that intermediate size devices have equal or greater strength to withstand the force of a detonation and have equivalent detonation arresting characteristics. A change of design, material, or construction which may affect the corrosion resistance, or ability to resist endurance burning, deflagrations or detonations shall be considered a change of model for the purpose of this paragraph.

9.2.1 The detonation flame arrester shall have the same dimensions, configuration, and most unfavorable clearances expected in production units.

9.2.2 A corrosion test shall be conducted. In this test, a complete detonation flame arrester, including a section of pipe similar to that to which it will be fitted, shall be exposed to a 20% sodium chloride solution spray at a temperature of 25 °C for a period of 240 hours, and allowed to dry for 48 hours. Following this exposure, all movable parts shall operate properly and there shall be no corrosion deposits which cannot be washed off.

9.2.3 The detonation flame arrester shall be subjected to a hydrostatic pressure test of at least 350 psig for ten minutes without rupturing, leaking, or showing permanent distortion.

9.2.4 Flow characteristics as declared by the manufacturer, shall be demonstrated by appropriate tests.

9.2.5 Detonation flame arresters shall be tested for endurance burn and deflagration/detonation in accordance with the test procedures in section 14. Type I detonation flame arresters shall show no flame passage when subjected to both tests. Type II detonation flame arresters shall show no evidence of flame passage during the detonation/deflagration tests in section 14.3. Type II detonation flame arresters shall be tested for endurance burn in accordance with section 14.2.

From the endurance burn test of a Type II detonation flame arresters, the maximum temperature reached and the test duration shall be recorded and provided as part of the laboratory test report.

9.2.6 Where a detonation flame arrester is provided with cowls, weather hoods and deflectors, etc., it shall be tested in each configuration in which it is provided.

9.2.7 Detonation flame arresters which are provided with a heating arrangement designed to maintain the surface temperature of the device above 85 °C shall pass the required tests at the maximum heated operating temperature.

9.2.8 Each finished detonation arrester shall be pneumatically tested at 10 psig to ensure there are no defects or leakage.

10. Inspection

10.1 The manufacturer shall afford the purchaser's inspector all reasonable access necessary to assure that the device is being furnished in accordance with this standard. All examinations and inspections shall be made at the place of manufacture, unless otherwise agreed upon.

10.2 Each finished detonation arrester shall be visually and dimensionally checked to ensure that the device corresponds to this standard, is certified in accordance with section 11 and is marked in accordance with section 12. Special attention shall be given to the checking of welds and the proper fit-ups of joints (see sections 8.5 and 8.6).

11. Certification

11.1 Manufacturer's certification that a detonation flame arrester meets this standard shall be provided in an instruction manual. The manual shall include as applicable:

11.1.1 Installation instructions and a description of all configurations tested (reference paragraph 9.2.6). Installation instructions to include the device's limitations.

11.1.2 Operating instructions.

11.1.3 Maintenance requirements.

11.1.3.1 Instructions on how to determine when arrester cleaning is required and the method of cleaning.

11.1.4 Copy of test report (see section 9.1.1).

11.1.5 Flow test data, maximum temperature and time tested (Type II).

11.1.6 The ambient air temperature range over which the device will effectively prevent the passage of flame.

NOTE: Other factors such as condensation and freezing of vapors should be evaluated at the time of equipment specification.

11.1.7 The maximum operating pressure for which the device is suitable.

12. Marking

12.1 Each detonation flame arrester shall be permanently marked indicating:

12.1.1 Manufacturer's name or trademark.

12.1.2 Style, type, model or other manufacturer's designation for the detonation flame arrester.

12.1.3 Size of the inlet and outlet.

12.1.4 Type of device (Type I or II).

12.1.5 Direction of flow through the detonation flame arrester.

12.1.6 Test laboratory and report number.

12.1.7 Lowest MESH of gases that the detonation flame arrester is suitable for.

12.1.8 ASTM designation of this standard.

12.1.9 Ambient air operating temperature range.

12.1.10 Maximum operating pressure.

13. *Quality Assurance*

13.1 Detonation flame arresters shall be designed, manufactured and tested in a manner that ensures they meet the characteristics of the unit tested in accordance with this standard.

13.2 The detonation flame arrester manufacturer shall maintain the quality of the arresters that are designed, tested and marked in accordance with this standard. At no time shall a detonation flame arrester be sold with this standard designation that does not meet the requirements herein.

14. *Test Procedures for Detonation Arresters*

14.1 *Media/Air Mixtures*

14.1.1 For vapors from flammable or combustible liquids with a MESH greater than or equal to 0.9 mm, technical grade hexane or gasoline vapors shall be used for all tests in this section except technical grade propane may be used for the deflagration/detonation tests in section 14.3. For vapors with a MESH less than 0.9 mm, the specific vapor (or alternatively, a media with a MESH less than or equal to the MESH of the vapor) must be used as the test medium in all Section 14 tests.

14.1.2 Hexane, propane, gasoline and other test vapors shall be mixed with air to form the most easily ignitable mixture.⁵

14.2 *Endurance Burn Test Procedure*

14.2.1 An endurance burning test shall be carried out as follows:

14.2.1.1 The test rig shall consist of an apparatus producing an explosive mixture, a small tank with a diaphragm, a prototype of the detonation flame arrester and a firing source in close proximity to the test device (see Figure 1). The detonation flame arrester shall be installed so that the mixture emission is vertically upwards, or installed in the position for which it is designed and which will cause the most severe heating of the device under the prescribed endurance burn conditions. In this position the mixture shall be ignited.

14.2.1.2 Endurance burn test shall start by using the most easily ignitable test vapor/air mixture with the aid of a pilot flame or a spark igniter at the outlet. The flammable mixture may be reignited as necessary in the course of the endurance burn.

14.2.1.3 Temperature measurement will be performed on the surface of the arrester element half way between the center and its edge.

14.2.1.4 By varying the proportions of the flammable mixture and the flow rate, the detonation flame arrester shall be heated by a stable flame on the surface of the arrester until the highest obtainable temperature is reached on the ignited side or until the temperature on the side which was not ignited (protected side) rises 100 °C.

14.2.1.5 The flammable mixture proportions will then be varied again until the conditions which result in the highest temperature on the protected side are achieved. This temperature shall be maintained for a period of ten minutes, after which the flow shall be stopped and the conditions observed. The highest attainable temperature is considered to have been reached when any subsequent rise of temperature does not exceed 0.5 °C per minute over a ten minute period.

14.2.1.6 If difficulty arises in establishing the highest attainable temperature on the protected side, the following criteria shall apply. When the increase in temperature on the protected side occurs so slowly that its temperature does not rise 100 °C, the conditions which produced the highest temperature on the ignited side of the arrester will be maintained for two hours. For the condition in which the temperature on the protected side continues to rise at a rate in excess of 0.5 °C per minute for a 10 minute period, endurance burning shall be continued, using the most severe conditions of flammable mixtures and flow rate, for a period of two hours. In either of these cases, at the end of the two hour period, the flow shall be stopped and the conditions observed. The two hour interval shall be measured commencing with the setting of the conditions which produced the most severe conditions of mixture and flow rate. For Type I detonation flame arresters, flame passage shall not occur during this test. For Type II detonation flame arresters, the maximum temperature obtained, and the time elapsed from the time when the most severe conditions are set to when flame passage occurs, shall be recorded. However, for Type II detonation flame arresters the test may be terminated 15 minutes after setting the most severe conditions on the protected side.

14.3 *Deflagration/Detonation Test Procedure*

14.3.1 A detonation flame arrester shall be installed at one end of a pipe of the same diameter as the inlet of the detonation flame arrester (see Figure 2). The length and configuration of the test pipe shall develop a stable detonation⁶ at the device and shall be capable, by change in its length or configuration, of developing deflagrations and unstable (overdriven) detonations as measured on the side of the pipe where ignition occurs (run-up side). For deflagration testing, two

test piping arrangements shall be used on the outlet side of the detonation flame arrester (the side which is not ignited). In both of the following end arrangements, the outlet side pipe diameter shall be equal to that on the run-up side. In one arrangement, the outlet side pipe shall be at least 10 pipe diameters long with a plastic bag over the free end. (Alternate end of pipe closures are also acceptable provided they easily give way during the course of the test, and the closure allows the required gas concentration to be maintained throughout the test piping arrangement.) In the other arrangement the outlet side pipe shall be fitted with a restriction located 0.6 meters from the outlet side arrester flange. The size of the restriction for each nominal size detonation flame arrester shall be as follows:

Nominal pipe diameter (inches)	Restriction diameter (inches)
3	1/2
4	1/2
6	1
8	1 1/2
10	1 1/2
12	2
18	2
24	2

The entire pipe shall be filled with the most easily ignitable vapor/air mixture to a test pressure corresponding to or greater than the upper limit of the device's maximum operating pressure (see 11.1.7). In order to obtain this test pressure, a device such as a bursting disc may be fitted on the open end of the device in place of the plastic bag. The concentration of the mixture should be verified by appropriate testing of the gas composition. The vapor/air mixture shall then be ignited.

14.3.2 Flame speeds shall be measured by optical devices capable of providing accuracy of $\pm 5\%$. These devices shall be situated no more than a distance equal to 3% of the length of the run-up pipe apart with one device no more than 8 inches from the end of the test pipe to which the detonation flame arrester is attached. In addition, each outlet arrangement described in paragraph 14.3.1 shall be fitted with an optical device located no more than 8 inches from the detonation flame arrester outlet.⁷

14.3.3 Explosion pressures within the pipe shall be measured by a high frequency transducer situated in the test pipe no more than 8 inches from the run-up side of the housing of the detonation flame arrester.

14.3.4 Using the first end arrangement (10 pipe diameter outlet) described in paragraph 14.3.1, a series of tests shall be conducted to determine the test pipe length and configuration that results in the maximum unstable (overdriven) detonation having the maximum measured flame speed at the detona-

tion flame arrester. (These tests may also be carried out using a single length of pipe with igniters spaced at varying distances from the arrester.) The flame speeds, explosion pressures and test pipe configurations shall be recorded for each of these tests. The piping configuration that resulted in the highest recorded unstable (overdriven) detonation flame speed shall be used, and the device shall be subjected to at least four additional unstable (overdriven) detonations. In the course of testing, the device shall also demonstrate its ability to withstand five stable detonations, five deflagrations (as determined by flame speed) where $\Delta P/P_0$ was less than 1 and five deflagrations (as determined by flame speed) where $\Delta P/P_0$ was greater than 1 but less than 10. Initiation of deflagrations shall be at several locations to generate a range for $\Delta P/P_0$. Deflagration tests using the restricted outlet arrangement described in paragraph 14.3.1 shall then be conducted. In these tests the device shall demonstrate its ability to stop five deflagrations (as determined by flame speed) generated by the same configurations which resulted in $\Delta P/P_0$ being less than 1 during the deflagration tests which were conducted without the restricted end arrangements, and five deflagrations (as determined by flame speed) generated by the same configurations which resulted in $\Delta P/P_0$ being greater than 1 but less than 10 during the deflagration tests which were conducted without the restricted end arrangements. No evidence of flame passage shall occur during these tests. The flame speeds and explosion pressures for each of these tests shall be recorded.

14.3.5 A device that successfully passes the tests of 14.3.4 shall be considered to be directional (suitable for arresting a detonation advancing only from the direction as tested) except:

14.3.5.1 A device may be tested according to 14.3.4 for detonations approaching from either direction, or

14.3.5.2 The design of the device is symmetrical where each end may be considered to be identical when approached by a detonation from either direction.

¹Available from the American Society for Testing and Materials (ASTM), 100 Barr Harbor Dr., West Conshohocken, PA 19428-2959.

²Available from the American Society of Mechanical Engineers International, Three Park Avenue, New York, NY 10016-5990.

³Available from the International Maritime Organization, 4 Albert Embankment, London SE1 7SR, England.

⁴Available from the International Electrotechnical Commission, 1 rue de Varembe, Geneva, Switzerland.

⁵See IEC Publication 79-1.

⁶Some data are available for the estimation of flame speeds in horizontal pipes without detonation flame arresters. Some

data indicate that the presence of small obstacles, fittings or bends in the test pipe can accelerate the flame speeds appreciably.

⁷Other pressure and/or flame speed measuring techniques may be used if effective.

FIGURE 1

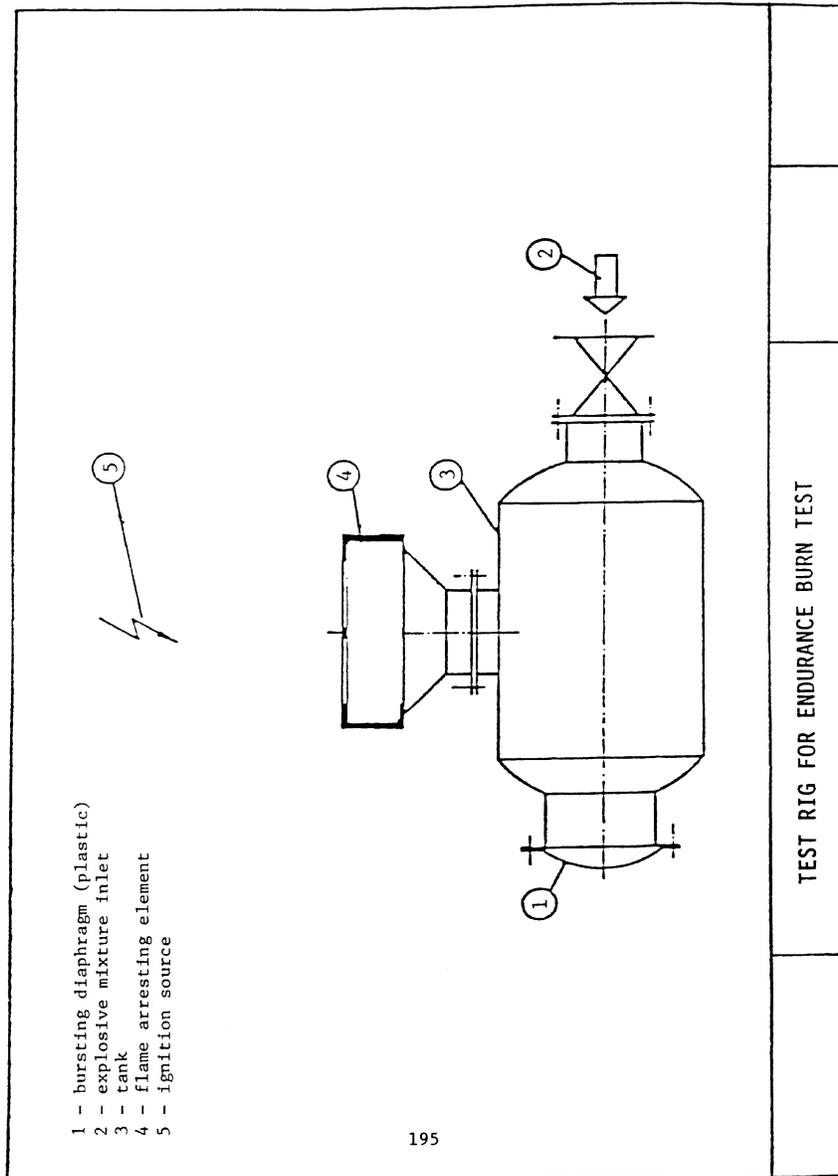
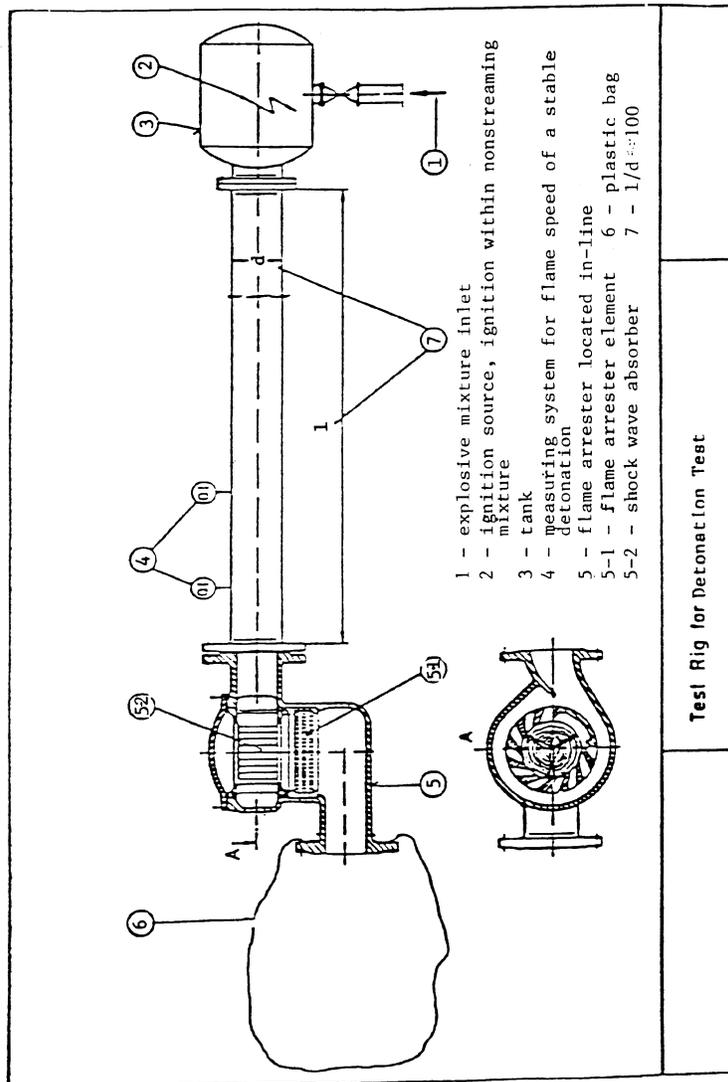


Figure 2



ATTACHMENT 1

Inflammable gas or vapour	Experimental maximum safe gap	
	mm	in.
Methane	1.170	0.046
Blast furnace gas	1.193	0.047
Propane	0.965	0.038
Butane	1.066	0.042
Pentane	1.016	0.040
Hexane	0.965	0.038
Heptane	0.965	0.038
Iso-octane	1.040	0.041
Decane	1.016	0.040
Benzene	0.99	0.039
Xylene	1.066	0.042
Cyclohexane	0.94	0.037
Acetone	1.016	0.040
Ethylene	0.71	0.028
Methyl-ethyl-ketone	1.016	0.040
Carbon monoxide	0.915	0.036
Methyl-acetate	0.990	0.039
Ethyl-acetate	1.04	0.041
Propyl-acetate	1.04	0.041
Butyl-acetate	1.016	0.040
Amyl-acetate	0.99	0.039
Methyl alcohol	0.915	0.036
Ethyl alcohol	1.016	0.040
Iso-butyl-alcohol	0.965	0.038
Butyl-alcohol (Normal)	0.94	0.037
Amyl-alcohol	0.99	0.039
Ethyl-ether	0.864	0.034
Coal gas (H ₂ 57%)	0.482	0.019
Acetylene	≤0.025	≤0.001
Carbon disulphide	0.203	0.008
Hydrogen	0.102	0.004
Blue water gas (H ₂ 53% CO 47%)	0.203	0.008
Ethyl nitrate	≤0.025	≤0.001
Ammonia	¹ 3.33	¹ 0.133
Ethylene oxide	0.65	0.026
Ethyl nitrite	0.922	0.038

¹ Approximately.

[CGD 88-102, 55 FR 25435, June 21, 1990; 55 FR 39270, Sept. 26, 1990, as amended by CGD 96-026, 61 FR 33666, June 28, 1996; USCG-1999-5832, 64 FR 34715, June 29, 1999; USCG-2000-7223, 65 FR 40058, June 29, 2000; USCG-2010-0351, 75 FR 36284, June 25, 2010; USCG-1999-5150, 78 FR 42641, July 16, 2013; USCG-2014-0410, 79 FR 38436, July 7, 2014]

APPENDIX B TO PART 154 [RESERVED]

APPENDIX C TO PART 154—GUIDELINES FOR DETERMINING AND EVALUATING REQUIRED RESPONSE RESOURCES FOR FACILITY RESPONSE PLANS

1. Purpose

1.1 The purpose of this appendix is to describe the procedures for identifying response resources to meet the requirements of subpart F of this part. These guidelines will be used by the facility owner or operator in preparing the response plan and by the Captain of the Port (COTP) when reviewing them. Response resources identified in subparts H and I of this part should be selected

using the guidelines in section 2 and Table 1 of this appendix.

2. Equipment Operability and Readiness

2.1 All equipment identified in a response plan must be designed to operate in the conditions expected in the facility's geographic area. These conditions vary widely based on location and season. Therefore, it is difficult to identify a single stockpile of response equipment that will function effectively in each geographic location.

2.2 Facilities handling, storing, or transporting oil in more than one operating environment as indicated in Table 1 of this appendix must identify equipment capable of successfully functioning in each operating environment.

2.3 When identifying equipment for response plan credit, a facility owner or operator must consider the inherent limitations in the operability of equipment components and response systems. The criteria in Table 1 of this appendix should be used for evaluating the operability in a given environment. These criteria reflect the general conditions in certain operating areas.

2.3.1 The Coast Guard may require documentation that the boom identified in a response plan meets the criteria in Table 1. Absent acceptable documentation, the Coast Guard may require that the boom be tested to demonstrate that it meets the criteria in Table 1. Testing must be in accordance with ASTM F 715 (incorporated by reference, see §154.106), or other tests approved by the Coast Guard.

2.4 Table 1 of this appendix lists criteria for oil recovery devices and boom. All other equipment necessary to sustain or support response operations in the specified operating environment must be designed to function in the same conditions. For example, boats which deploy or support skimmers or boom must be capable of being safely operated in the significant wave heights listed for the applicable operating environment.

2.5 A facility owner or operator must refer to the applicable local contingency plan or ACP, as appropriate, to determine if ice, debris, and weather-related visibility are significant factors in evaluating the operability of equipment. The local contingency plan or ACP will also identify the average temperature ranges expected in the facility's operating area. All equipment identified in a response plan must be designed to operate within those conditions or ranges.

2.6 The requirements of subparts F, G, H and I of this part establish response resource mobilization and response times. The distance of the facility from the storage location of the response resources must be used to determine whether the resources can arrive on scene within the stated time. A facility owner or operator shall include the time for notification, mobilization, and travel

time of response resources identified to meet the maximum most probable discharge and Tier 1 worst case discharge response time requirements. For subparts F and G, tier 2 and 3 response resources must be notified and mobilized as necessary to meet the requirements for arrival on scene in accordance with §154.1045 or §154.1047 of subpart F, or §154.1135 of subpart G, as appropriate. An on water speed of 5 knots and a land speed of 35 miles per hour is assumed unless the facility owner or operator can demonstrate otherwise.

2.7 For subparts F and G, in identifying equipment, the facility owner or operator shall list the storage location, quantity, and manufacturer's make and model. For oil recovery devices, the effective daily recovery capacity, as determined using section 6 of this appendix must be included. For boom, the overall boom height (draft plus freeboard) should be included. A facility owner or operator is responsible for ensuring that identified boom has compatible connectors.

2.8 For subparts H and I, in identifying equipment, the facility owner or operator shall list the storage location, quantity, and manufacturer's make and model. For boom, the overall boom height (draft plus freeboard) should be included. A facility owner or operator is responsible for ensuring that identified boom has compatible connectors.

3. *Determining Response Resources Required for the Average Most Probable Discharge*

3.1 A facility owner or operator shall identify sufficient response resources available, through contract or other approved means as described in §154.1028(a), to respond to the average most probable discharge. The equipment must be designed to function in the operating environment at the point of expected use.

3.2 The response resources must include:

3.2.1 1,000 feet of containment boom or two times the length of the largest vessel that regularly conducts oil transfers to or from the facility, whichever is greater, and a means deploying it available at the spill site within 1 hour of the discovery of a spill.

3.2.2 Oil recovery devices with an effective daily recovery capacity equal to the amount of oil discharged in an average most probable discharge or greater available at the facility within 2 hours of the detection of an oil discharge.

3.2.3 Oil storage capacity for recovered oily material indicated in section 9.2 of this appendix.

4. *Determining Response Resources Required for the Maximum Most Probable Discharge*

4.1 A facility owner or operator shall identify sufficient response resources avail-

able, by contract or other approved means as described in §154.1028(a), to respond to discharges up to the maximum most probable discharge volume for that facility. This will require response resources capable of containing and collecting up to 1,200 barrels of oil or 10 percent of the worst case discharge, whichever is less. All equipment identified must be designed to operate in the applicable operating environment specified in Table 1 of this appendix.

4.2 Oil recovery devices identified to meet the applicable maximum most probable discharge volume planning criteria must be located such that they arrive on scene within 6 hours in higher volume port areas (as defined in §154.1020) and the Great Lakes and within 12 hours in all other areas.

4.3 Because rapid control, containment, and removal of oil is critical to reduce spill impact, the effective daily recovery capacity for oil recovery devices must equal 50 percent of the planning volume applicable for the facility as determined in section 4.1 of this appendix. The effective daily recovery capacity for oil recovery devices identified in the plan must be determined using the criteria in section 6 of this appendix.

4.4 In addition to oil recovery capacity, the plan must identify sufficient quantities of containment boom available, by contract or other approved means as described in §154.1028(a), to arrive within the required response times for oil collection and containment and for protection of fish and wildlife and sensitive environments. While the regulation does not set required quantities of boom for oil collection and containment, the response plan must identify and ensure, by contract or other approved means as described in §154.1028(a), the availability of the boom identified in the plan for this purpose.

4.5 The plan must indicate the availability of temporary storage capacity to meet the guidelines of section 9.2 of this appendix. If available storage capacity is insufficient to meet this level, then the effective daily recovery capacity must be derated to the limits of the available storage capacity.

4.6 The following is an example of a maximum most probable discharge volume planning calculation for equipment identification in a higher volume port area: The facility's worst case discharge volume is 20,000 barrels. Ten percent of this is 2,000 barrels. Since this is greater than 1,200 barrels, 1,200 barrels is used as the planning volume. The effective daily recovery capacity must be 50 percent of this, or 600 barrels per day. The ability of oil recovery devices to meet this capacity will be calculated using the procedures in section 6 of this appendix. Temporary storage capacity available on scene must equal twice the daily recovery rate as indicated in section 9 of this appendix, or 1,200 barrels per day. This is the information the facility owner or operator will use to

identify and ensure the availability of, through contract or other approved means as described in §154.1028(a), the required response resources. The facility owner will also need to identify how much boom is available for use.

5. Determining Response Resources Required for the Worst Case Discharge to the Maximum Extent Practicable

5.1 A facility owner or operator shall identify and ensure availability of, by contract or other approved means, as described in §154.1028(a), sufficient response resources to respond to the worst case discharge of oil to the maximum extent practicable. Section 7 of this appendix describes the method to determine the required response resources.

5.2 Oil spill response resources identified in the response plan and available through contract or other approved means, as described in §154.1028(a), to meet the applicable worst case discharge planning volume must be located such that they can arrive at the scene of a discharge within the times specified for the applicable response tiers listed in §154.1045.

5.3 The effective daily recovery capacity for oil recovery devices identified in a response plan must be determined using the criteria in section 6 of this appendix. A facility owner or operator shall identify the storage locations of all response resources that must be used to fulfill the requirements for each tier. The owner or operator of a facility whose required daily recovery capacity exceeds the applicable response capability caps in Table 5 of this appendix shall identify sources of additional equipment, their locations, and the arrangements made to obtain this equipment during a response. The owner or operator of a facility whose calculated planning volume exceeds the applicable contracting caps in Table 5 shall identify sources of additional equipment equal to twice the cap listed in Tiers 1, 2, and 3 or the amount necessary to reach the calculated planning volume, whichever is lower. The resources identified above the cap must be capable of arriving on scene not later than the Tiers 1, 2, and 3 response times in §154.1045. No contract is required. While general listings of available response equipment may be used to identify additional sources, a response plan must identify the specific sources, locations, and quantities of equipment that a facility owner or operator has considered in his or her planning. When listing Coast Guard classified oil spill removal organization(s) which have sufficient removal capacity to recover the volume above the response capability cap for the specific facility, as specified in Table 5 of this appendix, it is not necessary to list specific quantities of equipment.

5.4 A facility owner or operator shall identify the availability of temporary stor-

age capacity to meet the requirements of section 9.2 of this appendix. If available storage capacity is insufficient to meet this requirement, then the effective daily recovery capacity must be derated to the limits of the available storage capacity.

5.5 When selecting response resources necessary to meet the response plan requirements, the facility owner or operator must ensure that a portion of those resources are capable of being used in close-to-shore response activities in shallow water. The following percentages of the on-water response equipment identified for the applicable geographic area must be capable of operating in waters of 6 feet or less depth:

- (i) Offshore—10 percent
- (ii) Nearshore/inland/Great Lakes/ivers and canals—20 percent.

5.6 In addition to oil spill recovery devices, a facility owner or operator shall identify sufficient quantities of boom that are available, by contract or other approved means as described in §154.1028(a), to arrive on scene within the required response times for oil containment and collection. The specific quantity of boom required for collection and containment will depend on the specific recovery equipment and strategies employed. A facility owner or operator shall also identify sufficient quantities of oil containment boom to protect fish and wildlife and sensitive environments for the number of days and geographic areas specified in Table 2. Sections 154.1035(b)(4)(iii) and 154.1040(a), as appropriate, shall be used to determine the amount of containment boom required, through contract or other approved means as described in §154.1028(a), to protect fish and wildlife and sensitive environments.

5.7 A facility owner or operator must also identify, through contract or other approved means as described in §154.1028(a), the availability of an oil spill removal organization capable of responding to a shoreline cleanup operation involving the calculated volume of oil and emulsified oil that might impact the affected shoreline. The volume of oil that must be planned for is calculated through the application of factors contained in Tables 2 and 3. The volume calculated from these tables is intended to assist the facility owner or operator in identifying a contractor with sufficient resources and expertise. This planning volume is not used explicitly to determine a required amount of equipment and personnel.

6. Determining Effective Daily Recovery Capacity for Oil Recovery Devices

6.1 Oil recovery devices identified by a facility owner or operator must be identified by manufacturer, model, and effective daily recovery capacity. These rates must be used

to determine whether there is sufficient capacity to meet the applicable planning criteria for the average most probable discharge, maximum most probable discharge, and worst case discharge to the maximum extent practicable.

6.2 For the purpose of determining the effective daily recovery capacity of oil recovery devices, the formula listed in section 6.2.1 of this appendix will be used. This method considers potential limitations due to available daylight, weather, sea state, and percentage of emulsified oil in the recovered material. The Coast Guard may assign a lower efficiency factor to equipment listed in a response plan if it determines that such a reduction is warranted.

6.2.1 The following formula must be used to calculate the effective daily recovery capacity:

$$R = T \times 24 \text{ hours} \times E$$

R = Effective daily recovery capacity

T = Throughput rate in barrels per hour (nameplate capacity)

E = 20 percent Efficiency factor (or lower factor as determined by Coast Guard)

6.2.2 For those devices in which the pump limits the throughput of liquid, throughput rate will be calculated using the pump capacity.

6.2.3 For belt or mop type devices, the throughput rate will be calculated using the speed of the belt or mop through the device, assumed thickness of oil adhering to or collected by the device, and surface area of the belt or mop. For purposes of this calculation, the assumed thickness of oil will be $\frac{1}{4}$ inch.

6.2.4 Facility owners or operators including oil recovery devices whose throughput is not measurable using a pump capacity or belt/mop speed may provide information to support an alternative method of calculation. This information must be submitted following the procedures in paragraph 6.3.2 of this appendix.

6.3 As an alternative to 6.2, a facility owner or operator may submit adequate evidence that a different effective daily recovery capacity should be applied for a specific oil recovery device. Adequate evidence is actual verified performance data in spill conditions or tests using ASTM F 631 (incorporated by reference, see §154.106), or an equivalent test approved by the Coast Guard.

6.3.1 The following formula must be used to calculate the effective daily recovery capacity under this alternative:

$$R = D \times U$$

R = Effective daily recovery capacity

D = Average Oil Recovery Rate in barrels per hour (Item 26 in ASTM F 808; Item 13.2.16 in ASTM F 631; or actual performance data)

U = Hours per day that a facility owner or operator can document capability to operate equipment under spill conditions.

Ten hours per day must be used unless a facility owner or operator can demonstrate that the recovery operation can be sustained for longer periods.

6.3.2 A facility owner or operator proposing a different effective daily recovery rate for use in a response plan shall provide data for the oil recovery devices listed. The following is an example of these calculations:

A weir skimmer identified in a response plan has a manufacturer's rated throughput at the pump of 267 gallons per minute (gpm).

$$267 \text{ gpm} = 381 \text{ barrels per hour}$$

$$R = 381 \times 24 \times .2 = 1829 \text{ barrels per day}$$

After testing using ASTM procedures, the skimmer's oil recovery rate is determined to be 220 gpm. The facility owner or operator identifies sufficient response resources available to support operations 12 hours per day.

$$220 \text{ gpm} = 314 \text{ barrels per hour}$$

$$R = 314 \times 12 = 3768 \text{ barrels per day}$$

The facility owner or operator will be able to use the higher rate if sufficient temporary oil storage capacity is available. Determinations of alternative efficiency factors under paragraph 6.2 or alternative effective daily recovery capacities under paragraph 6.3 of this appendix will be made by Commandant (CG-CPE), Attn: Office of Crisis and Contingency Preparedness and Exercise Policy, U.S. Coast Guard Stop 7516, 2703 Martin Luther King Jr. Avenue SE., Washington, DC 20593-7516. Response contractors or equipment manufacturers may submit required information on behalf of multiple facility owners or operators directly in lieu of including the request with the response plan submission.

7. Calculating the Worst Case Discharge Planning Volumes

7.1 The facility owner or operator shall plan for a response to a facility's worst case discharge. The planning for on-water recovery must take into account a loss of some oil to the environment due to evaporative and natural dissipation, potential increases in volume due to emulsification, and the potential for deposit of some oil on the shoreline.

7.2 The following procedures must be used to calculate the planning volume used by a facility owner or operator for determining required on water recovery capacity:

7.2.1 The following must be determined: The worst case discharge volume of oil in the facility; the appropriate group(s) for the type of oil handled, stored, or transported at the facility (non-persistent (Group I) or persistent (Groups II, III, or IV)); and the facility's specific operating area. Facilities which handle, store, or transport oil from different petroleum oil groups must calculate each group separately. This information is to be

used with Table 2 of this appendix to determine the percentages of the total volume to be used for removal capacity planning. This table divides the volume into three categories: Oil lost to the environment; oil deposited on the shoreline; and oil available for on-water recovery.

7.2.2 The on-water oil recovery volume must be adjusted using the appropriate emulsification factor found in Table 3 of this appendix. Facilities which handle, store, or transport oil from different petroleum groups must assume that the oil group resulting in the largest on-water recovery volume will be stored in the tank or tanks identified as constituting the worst case discharge.

7.2.3 The adjusted volume is multiplied by the on-water oil recovery resource mobilization factor found in Table 4 of this appendix from the appropriate operating area and response tier to determine the total on-water oil recovery capacity in barrels per day that must be identified or contracted for to arrive on-scene with the applicable time for each response tier. Three tiers are specified. For higher volume port areas, the contracted tiers of resources must be located such that they can arrive on scene within 6, 30, and 54 hours of the discovery of an oil discharge. For all other river, inland, nearshore, offshore areas, and the Great Lakes, these tiers are 12, 36, and 60 hours.

7.2.4 The resulting on-water recovery capacity in barrels per day for each tier must be used to identify response resources necessary to sustain operations in the applicable operating area. The equipment must be capable of sustaining operations for the time period specified in Table 2 of this appendix. The facility owner or operator must identify and ensure the availability, through contract or other approved means as described in §154.1028(a), of sufficient oil spill recovery devices to provide the effective daily recovery oil recovery capacity required. If the required capacity exceeds the applicable cap specified in Table 5 of this appendix, then a facility owner or operator shall ensure, by contract or other approved means as described in §154.1028(a), only for the quantity of resources required to meet the cap, but shall identify sources of additional resources as indicated in §154.1045(m). The owner or operator of a facility whose planning volume exceeds the cap for 1993 must make arrangements to identify and ensure the availability, through contract or other approved means as described in §154.1028(a), of the additional capacity in 1998 or 2003, as appropriate. For a facility that handles, stores, or transports multiple groups of oil, the required effective daily recovery capacity for each group is calculated before applying the cap.

7.3 The following procedures must be used to calculate the planning volume for identifying shoreline cleanup capacity:

7.3.1 The following must be determined: The worst case discharge volume of oil for the facility; the appropriate group(s) for the type of oil handled, stored, or transported at the facility (non-persistent (Group I) or persistent (Groups II, III, or IV)); and the operating area(s) in which the facility operates. For a facility storing oil from different groups, each group must be calculated separately. Using this information, Table 2 of this appendix must be used to determine the percentages of the total planning volume to be used for shoreline cleanup resource planning.

7.3.2 The shoreline cleanup planning volume must be adjusted to reflect an emulsification factor using the same procedure as described in section 7.2.2.

7.3.3 The resulting volume will be used to identify an oil spill removal organization with the appropriate shoreline cleanup capability.

7.3.4 The following is an example of the procedure described above: A facility receives oil from barges via a dock located on a bay and transported by piping to storage tanks. The facility handles Number 6 oil (specific gravity .96) and stores the oil in tanks where it is held prior to being burned in an electric generating plant. The MTR segment of the facility has six 18-inch diameter pipelines running one mile from the dock-side manifold to several storage tanks which are located in the non-transportation-related portion of the facility. Although the facility piping has a normal working pressure of 100 pounds per square inch, the piping has a maximum allowable working pressure (MAWP) of 150 pounds per square inch. At MAWP, the pumping system can move 10,000 barrels (bbls) of Number 6 oil every hour through each pipeline. The facility has a roving watchman who is required to drive the length of the piping every 2 hours when the facility is receiving oil from a barge. The facility operator estimates that it will take approximately 10 minutes to secure pumping operations when a discharge is discovered. Using the definition of worst case discharge provided in §154.1029(b)(ii), the following calculation is provided:

2 hrs + 0.17 hour × 10,000 bbls per hour	21,700
Piping volume = 37,322 ft ³ + 5.6 ft ³ /bbl	+ 6,664
Discharge volume per pipe	28,364
Number of pipelines	× 6
Worst case discharge from MTR facility	170,184

To calculate the planning volumes for on-shore recovery:

Worst case discharge: 170,184 bbls. Group IV oil
 Emulsification factor (from Table 3): 1.4
 Operating Area impacted: Inland

Planned percent oil onshore recovery (from Table 2): Inland 70%

Planning volumes for onshore recovery: Inland $170,184 \times .7 \times 1.4 = 166,780$ bbls.

Conclusion: The facility owner or operator must contract with a response resource capable of managing a 166,780 barrel shoreline cleanup.

To calculate the planning volumes for on-water recovery:

Worst case discharge: 170,184 bbls. Group IV oil

Emulsification factor (from Table 3): 1.4

Operating Area impacted: Inland

Planned percent oil on-water recovery (from Table 2): Inland 50%

Planning volumes for on-water recovery: Inland $170,184 \times .5 \times 1.4 = 119,128$ bbls.

To determine the required resources for on-water recovery for each tier, use the mobilization factors from Table 4:

	Tier 1	Tier 2	Tier 3
Inland = 119,128 bbls.	$\times .15$	$\times .25$	$\times .40$
Barrels per day (bpd)	17,869	29,782	47,652

Conclusion: Since the requirements for all tiers for inland exceed the caps, the facility owner will only need to contract for 10,000 bpd for Tier 1, 20,000 bpd for Tier 2, and 40,000 bpd for Tier 3. Sources for the bpd on-water recovery resources above the caps for all three Tiers need only be identified in the response plan.

Twenty percent of the capability for Inland, for all tiers, must be capable of operating in water with a depth of 6 feet or less.

The facility owner or operator will also be required to identify or ensure, by contract or other approved means as described in §154.1028(a), sufficient response resources required under §§154.1035(b)(4) and 154.1045(k) to protect fish and wildlife and sensitive environments identified in the response plan for the worst case discharge from the facility.

The COTP has the discretion to accept that a facility can operate only a limited number of the total pipelines at a dock at a time. In those circumstances, the worst case discharge must include the drainage volume from the piping normally not in use in addition to the drainage volume and volume of oil discharged during discovery and shut down of the oil discharge from the operating piping.

8. Determining the Capability of High-Rate Response Methods

8.1. Calculate cumulative dispersant application capacity as follows:

8.1.1 A facility owner or operator must plan either for a dispersant capacity to respond to a facility's worst case discharge (WCD) of oil, or for the amount of the dispersant resource cap as required by

§154.1045(i)(3) of this chapter, whichever is the lesser amount. When planning for the cumulative application capacity required, the calculations must account for the loss of some oil to the environment due to natural dissipation causes (primarily evaporation). The following procedure must be used to determine the cumulative application requirements:

8.1.2 Determine the WCD volume of oil in gallons and the appropriate oil group for the type of petroleum oil (persistent Groups II, III, and IV). For facilities with mixed petroleum oils, assume a total WCD volume using the group that constitutes the largest portion of the oil being handled or the group with the smallest natural dissipation factor;

8.1.3 Multiply the total WCD amount in gallons by the natural dissipation factor for the appropriate oil group as follows: Group II factor is 0.50; Group III is 0.30; and Group IV is 0.10. This represents the amount of oil that can be expected to be lost to natural dissipation in a nearshore environment. Subtract the oil amount lost to natural dissipation from the total WCD amount to determine the remaining oil available for treatment by dispersant application; and

8.1.4 Multiply the oil available for dispersant treatment by the dispersant-to-oil planning application ratio of 1 part dispersant to 20 parts oil (0.05). The resulting number represents the cumulative total dispersant-application capability that must be ensured available within the first 60 hours.

8.1.5(i) The following is an example of the procedure described in paragraphs 8.1.1 through 8.1.4 above: A facility with a 1,000,000 gallon WCD of crude oil (specific gravity 0.87) is located in an area with pre-authorization for dispersant use in the nearshore environment on the U.S. East Coast:

WCD: 1,000,000 gallons, Group III oil.

Natural dissipation factor for Group III: 30 percent.

General formula to determine oil available for dispersant treatment: $(WCD) - [(WCD) \times (\text{natural dissipation factor})] = \text{available oil}$.

E.g., $1,000,000 \text{ gal} - (1,000,000 \text{ gal} \times .30) = 700,000$ gallons of available oil.

Cumulative application capacity = Available oil \times planning application ratio (1 gal dispersant/20 gals oil = 0.05).

E.g., $700,000 \text{ gal oil} \times (0.05) = 35,000$ gallons cumulative dispersant-application capacity.

(ii) The requirements for cumulative dispersant-application capacity (35,000 gallons) for this facility's WCD is less than the overall dispersant capability for non-Gulf Coast waters required by §155.1045(i)(3) of this chapter. Because paragraph 8.1.1 of this appendix requires owners and operators to ensure the availability of the lesser of a facility's dispersant requirements for WCD or the amount of the dispersant cap provided for in §154.1045(i)(3), the facility in this example would be required to ensure the availability

of 35,000 gallons of dispersant. More specifically, this facility would be required to meet the following tier requirements in §154.1045(i)(3), which total 35,000 gallons application:

Tier 1—4,125 gallons—Completed in 12 hours.

Tier 2—23,375 gallons—Completed in 36 hours.

Tier 3—7,500 gallons—Completed in 60 hours.

8.2 Determine Effective Daily Application Capacities (EDACs) for dispersant response systems as follows:

8.2.1 EDAC planning estimates for compliance with the dispersant application requirements in §154.1045(i)(3) are to be based on:

8.2.1.1 The spill occurring at the facility;

8.2.1.2 Specific dispersant application platform operational characteristics identified in the EDSP or as demonstrated by operational tests;

8.2.1.3 Locations of primary dispersant staging sites; and

8.2.1.4 Locations and quantities of dispersant stockpiles.

8.2.2 EDAC calculations with supporting documentation must be submitted to the NSFCC for classification as a Dispersant Oil Spill Removal Organization.

8.2.3(i) EDAC can also be calculated using the Dispersant Mission Planner 2 (EDSP). The EDSP is a downloadable application that calculates EDAC for different dispersant response systems. It is located on the Internet at: <http://www.response.restoration.noaa.gov/spilltools>.

(ii) The DMP2 contains operating information for the vast majority of dispersant application platforms, including aircraft, both rotary and fixed wing, and vessels. The DMP2 produces EDAC estimates by performing calculations based on performance parameters of dispersant application platforms, locations of primary dispersant staging sites, home-based airport or port locations, and the facility location (for the spill site).

8.2.4 For each Captain of the Port zone where a dispersant response capability is required, the response plan must identify:

8.2.4.1 The type, number, and location of each dispersant-application platform intended for use to meet dispersant delivery requirements specified in §154.1045(i)(3) of this chapter;

8.2.4.2 The amount and location of available dispersant stockpiles to support each platform; and,

8.2.4.3 A primary staging site for each platform that will serve as its base of operations for the duration of the response.

8.3 In addition to the equipment and supplies required, a facility owner or operator must identify a source of support to conduct the monitoring and post-use effectiveness evaluation required by applicable regional plans and ACPs.

8.4 Identification of the resources for dispersant application does not imply that the use of this technique will be authorized. Actual authorization for use during a spill response will be governed by the provisions of the National Oil and Hazardous Substances Contingency Plan (40 CFR part 300) and the applicable Local or Area Contingency Plan.

9. Additional Equipment Necessary To Sustain Response Operations

9.1 A facility owner or operator is responsible for ensuring that sufficient numbers of trained personnel and boats, aerial spotting aircraft, containment boom, sorbent materials, boom anchoring materials, and other supplies are available to sustain response operations to completion. All such equipment must be suitable for use with the primary equipment identified in the response plan. A facility owner or operator is not required to list these response resources, but shall certify their availability.

9.2 A facility owner or operator shall evaluate the availability of adequate temporary storage capacity to sustain the effective daily recovery capacities from equipment identified in the plan. Because of the inefficiencies of oil spill recovery devices, response plans must identify daily storage capacity equivalent to twice the effective daily recovery rate required on scene. This temporary storage capacity may be reduced if a facility owner or operator can demonstrate by waste stream analysis that the efficiencies of the oil recovery devices, ability to decant waste, or the availability of alternative temporary storage or disposal locations will reduce the overall volume of oily material storage requirement.

9.3 A facility owner or operator shall ensure that his or her planning includes the capability to arrange for disposal of recovered oil products. Specific disposal procedures will be addressed in the applicable ACP.

TABLE 1—RESPONSE RESOURCE OPERATING CRITERIA OIL RECOVERY DEVICES

Operating environment	Significant wave height ¹	Sea State
Rivers and Canals	≤1 Foot	1
Inland	≤3 feet	2
Great Lakes	≤4 feet	2-3
Ocean	≤6 feet	3-4

BOOM				
Boom property	Use			
	Rivers and canals	Inland	Great Lakes	Ocean
Significant Wave Height ¹	≤1	≤3	≤4	≤6
Sea State	1	2	2-3	3-4
Boom height—in. (draft plus freeboard)	6-18	18-42	18-42	≤42
Reserve Buoyancy to Weight Ratio	2:1	2:1	2:1	3:1 to 4:1
Total Tensile Strength—lbs.	4,500	15-20,000	15-20,000	≤20,000
Skirt Fabric Tensile Strength—lbs	200	300	300	500
Skirt Fabric Tear Strength—lbs	100	100	100	125

¹ Oil recovery devices and boom must be at least capable of operating in wave heights up to and including the values listed in Table 1 for each operating environment.

TABLE 2—REMOVAL CAPACITY PLANNING TABLE

Spill location	Rivers and canals			Nearshore/inland Great Lakes			Offshore		
	3 Days			4 Days			6 Days		
Sustainability of on-water oil recovery	% Natural dissipation	% Re-covered floating oil	% Oil on shore	% Natural dissipation	% Re-covered floating oil	% Oil on shore	% Natural dissipation	% Re-covered floating oil	% Oil on shore
Oil group									
1 Non-persistent oils	80	10	10	80	20	10	95	5	/
2 Light crudes	40	15	45	50	50	30	75	25	5
3 Medium crudes and fuels	20	15	65	30	50	50	60	40	20
4 Heavy crudes and fuels	5	20	75	10	50	70	50	40	30

TABLE 3—EMULSIFICATION FACTORS FOR PETROLEUM OIL GROUPS

Non-Persistent Oil:	
Group I	1.0
Persistent Oil:	
Group II	1.8
Group III	2.0
Group IV	1.4

TABLE 4—ON WATER OIL RECOVERY RESOURCE MOBILIZATION FACTORS

Operating Area	Tier 1	Tier 2	Tier 3
Rivers & Canals30	.40	.60
Inland/Nearshore/Great Lakes15	.25	.40
Offshore10	.165	.21

Note: These mobilization factors are for total response resources mobilized, not incremental response resources.

TABLE 5—RESPONSE CAPABILITY CAPS BY OPERATING AREA

	Tier 1	Tier 2	Tier 3
February 18, 1993:			
All except rivers and canals, Great Lakes.	10K bbls/day	20K bbls/day	40K bbls/day/
Great Lakes	5K bbls/day	10K bbls/day	20K bbls/day.
Rivers and canals	1,500 bbls/day	3,000 bbls/day	6,000 bbls/day.
February 18, 1998:			
All except rivers and canals, Great Lakes.	12.5K bbls/day	25K bbls/day	50K bbls/day.
Great Lakes	6.25K bbls/day	12.3K bbls/day	25K bbls/day.
Rivers and canals	1,875 bbls/day	3,750 bbls/day	7,500 bbls/day.
February 18, 2003:			
All except rivers & canals & Great Lakes.	12.5K bbls/day	25K bbls/day	50K bbls/day.
Great Lakes	6.25K bbls/day	12.3K bbls/day	25K bbls/day.
Rivers & canals	1,875 bbls/day	3,750 bbls/day	7,500 bbls/day.

NOTE: The caps show cumulative overall effective daily recovery capacity, not incremental increases. TBD = To be determined.

[CGD 91-036, 61 FR 7933, Feb. 29, 1996, as amended by CGD 96-026, 61 FR 33666, June 28, 1996; USCG-1999-5151, 64 FR 67175, Dec. 1, 1999; USCG-2000-7223, 65 FR 40058, June 29, 2000; USCG-2005-21531, 70 FR 36349, June 23, 2005; USCG-2001-8661, 74 FR 45025, Aug. 31, 2009; USCG-2010-0351, 75 FR 36284, June 25, 2010; USCG-2014-0410, 79 FR 38436, July 7, 2014; USCG-2018-0874, 84 FR 30880, June 28, 2019]

APPENDIX D TO PART 154—TRAINING
ELEMENTS FOR OIL SPILL RESPONSE
PLANS

1. General

1.1 The portion of the plan dealing with training is one of the key elements of a response plan. This concept is clearly expressed by the fact that Congress, in writing OPA 90, specifically included training as one of the sections required in a vessel or facility response plan. In reviewing submitted response plans, it has been noted that the plans often do not provide sufficient information in the training section of the plan for either the user or the reviewer of the plan. In some cases, plans simply state that the crew and others will be trained in their duties and responsibilities, with no other information being provided. In other plans, information is simply given that required parties will receive the necessary worker safety training (HAZWOPER).

1.2 The training section of the plan need not be a detailed course syllabus, but it must contain sufficient information to allow the user and reviewer (or evaluator) to have an understanding of those areas that are believed to be critical. Plans should identify key skill areas and the training that is required to ensure that the individual identified will be capable of performing the duties prescribed to them. It should also describe how the training will be delivered to the various personnel. Further, this section of the plan must work in harmony with those sections of the plan dealing with exercises, the spill management team, and the qualified individual.

1.3 The material in this appendix D is not all-inclusive and is provided for guidance only.

2. Elements To Be Addressed

2.1 To assist in the preparation of the training section of a facility response plan, some of the key elements that should be addressed are indicated in the following sections. Again, while it is not necessary that the comprehensive training program for the company be included in the response plan, it is necessary for the plan to convey the elements that define the program as appropriate.

2.2 An effective spill response training program should consider and address the following:

2.2.1 Notification requirements and procedures.

2.2.2 Communication system(s) used for the notifications.

2.2.3 Procedures to mitigate or prevent any discharge or a substantial threat of a discharge of oil resulting from failure of manifold, mechanical loading arm, or other transfer equipment or hoses, as appropriate;

2.2.3.1 Tank overfill;

2.2.3.2 Tank rupture;

2.2.3.3 Piping rupture;

2.2.3.4 Piping leak, both under pressure and not under pressure, if applicable;

2.2.3.5 Explosion or fire;

2.2.3.6 Equipment failure (e.g., pumping system failure, relief valve failure, or other general equipment relevant to operational activities associated with internal or external facility transfers).

2.2.4 Procedures for transferring responsibility for direction of response activities from facility personnel to the spill management team.

2.2.5 Familiarity with the operational capabilities of the contracted oil spill removal organizations and the procedures to notify the activate such organizations.

2.2.6 Familiarity with the contracting and ordering procedures to acquire oil spill removal organization resources.

2.2.7 Familiarity with the ACP(s).

2.2.8 Familiarity with the organizational structures that will be used to manage the response actions.

2.2.9 Responsibilities and duties of the spill management team members in accordance with designated job responsibilities.

2.2.10 Responsibilities and authority of the qualified individual as described in the facility response plan and company response organization.

2.2.11 Responsibilities of designated individuals to initiate a response and supervise response resources.

2.2.12 Actions to take, in accordance with designated job responsibilities, in the event of a transfer system leak, tank overflow, or suspected cargo tank or hull leak.

2.2.13 Information on the cargoes handled by the vessel or facility, including familiarity with—

2.2.13.1 Cargo material safety data sheets;

2.2.13.2 Chemical characteristic of the cargo;

2.2.13.3 Special handling procedures for the cargo;

2.2.13.4 Health and safety hazards associated with the cargo; and

2.2.13.5 Spill and firefighting procedures for cargo.

2.2.14 Occupational Safety and Health Administration requirements for worker health and safety (29 CFR 1910.120).

3. Further Considerations

In drafting the training section of the facility response plan, some further considerations are noted below (these points are raised simply as a reminder):

3.1 The training program should focus on training provided to facility personnel.

3.2 An organization is comprised of individuals, and a training program should be structured to recognize this fact by ensuring

that training is tailored to the needs of the individuals involved in the program.

3.3 An owner or operator may identify equivalent work experience which fulfills specific training requirements.

3.4 The training program should include participation in periodic announced and unannounced exercises. This participation should approximate the actual roles and responsibilities of individual specified in the plan.

3.5 Training should be conducted periodically to reinforce the required knowledge and to ensure an adequate degree of preparedness by individuals with responsibilities under the facility response plan.

3.6 Training may be delivered via a number of different means; including classroom sessions, group discussions, video tapes, self-study workbooks, resident training courses, on-the-job training, or other means as deemed appropriate to ensure proper instruction.

3.7 New employees should complete the training program prior to being assigned job responsibilities which require participation in emergency response situations.

4. Conclusion

The information in this appendix is only intended to assist response plan preparers in reviewing the content of and in modifying the training section of their response plans. It may be more comprehensive than is needed for some facilities and not comprehensive enough for others. The Coast Guard expects that plan preparers have determined the training needs of their organizations created by the development of the response plans and the actions identified as necessary to increase the preparedness of the company and its personnel to respond to actual or threatened discharges of oil from their facilities.

[CGD 91-036, 61 FR 7938, Feb. 29, 1996]

PART 155—OIL OR HAZARDOUS MATERIAL POLLUTION PREVENTION REGULATIONS FOR VESSELS

Subpart A—General

Sec.

- 155.100 Applicability.
- 155.110 Definitions.
- 155.120 Equivalents.
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Subpart B—Vessel Equipment

- 155.200 Definitions.
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- 155.210 Discharge removal equipment for vessels less than 400 feet in length.
- 155.215 Discharge removal equipment for inland oil barges.
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- 155.225 Internal cargo transfer capability.
- 155.230 Emergency control systems for tank barges.
- 155.235 Emergency towing capability for oil tankers.
- 155.240 Damage stability information for oil tankers and offshore oil barges.
- 155.245 Damage stability information for inland oil barges.
- 155.250 Oil fuel tank protection.
- 155.310 Containment of oil and hazardous material cargo discharges.
- 155.320 Fuel oil and bulk lubricating oil discharge containment.
- 155.330 Oily mixture (bilge slops)/fuel oil tank ballast water discharges on U.S. non-oceangoing ships.
- 155.350 Oily mixture (bilge slops)/fuel oil tank ballast water discharges on oceangoing ships of less than 400 gross tons.
- 155.360 Oily mixture (bilge slops) discharges on oceangoing ships of 400 gross tons and above but less than 10,000 gross tons, excluding ships that carry ballast water in their fuel oil tanks.
- 155.370 Oily mixture (bilge slops)/fuel oil tank ballast water discharges on oceangoing ships of 10,000 gross tons and above and oceangoing ships of 400 gross tons and above that carry ballast water in their fuel oil tanks.
- 155.380 Oily water separating equipment and bilge alarm approval standards.
- 155.400 Platform machinery space drainage on oceangoing fixed and floating drilling rigs and other platforms.
- 155.410 Pumping, piping and discharge requirements for U.S. non-oceangoing ships of 100 gross tons and above.
- 155.420 Pumping, piping and discharge requirements for oceangoing ships of 100 gross tons and above but less than 400 gross tons.
- 155.430 Standard discharge connections for oceangoing ships of 400 gross tons and above.
- 155.440 Segregation of fuel oil and ballast water on new oceangoing ships of 4,000 gross tons and above, other than oil tankers, and on new oceangoing oil tankers of 150 gross tons and above.
- 155.450 Placard.
- 155.470 Prohibited spaces.
- 155.480 Overfill devices.
- 155.490 [Reserved]

Subpart C—Transfer Personnel, Procedures, Equipment, and Records

- 155.700 Designation of person in charge.
- 155.710 Qualifications of person in charge.