# DEPARTMENT OF TRANSPORTATION

**PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION**

**OFFICE OF PIPELINE SAFETY**


# PIPELINE SAFETY REGULATIONS

# PART 195

## TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

MINIMUM FEDERAL SAFETY STANDARDS

**(Current through Amendment 97)**

**TRAINING AND QUALIFICATIONS**
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# CAVEAT

***These materials were provided by the Pipeline and Hazardous Materials Safety Administration for use in its training programs. All reasonable efforts have been made to ensure that the material contained herein is accurate; however, due to the constantly changing domestic and international regulations, it is impossible to guarantee its absolute accuracy. This material is for training purposes only and is not meant to be relied on as a substitute for the Code of Federal Regulations or any other sources of applicable regulatory requirements.***

# PART 195 – TRANSPORTATION OF OF HAZARDOUS LIQUIDS BY PIPELINE

## NEW FORMAT

**For future versions of this manual, changes to the regulations will show highlights for deletions and underline for additions.**

### AMENDMENT TABLE OF SECTION REVISIONS FOR THIS VERSION OF PART 195

| PART 195 AMENDMENT NUMBER | EFFECTIVE DATE OF AMENDMENT | PARAGRAPH IMPACT | IN REFFERENCE TO: |
|---|---|---|---|
| [90]* | 02/17/09 | 195.3, .52, .57, .58, .59, .62 | ADMINISTRATIVE PROCEDURES, ADDRESS UPDATES, AND TECHNICAL AMENDMENTS |
| [91]* | 04/21/09 | 195.3 | INCORPORATION BY REFERENCE UPDATE: AMERICAN PETROLEUM INSTITUTE (API) STANDARDS 5L AND 1104 |
| 92 | 01/29/10 | 195.12 | EDITORIAL AMENDMENTS TO THE PIPELINE SAFETY REGULATIONS |
| 93 | 02/01/10 | 195.2, .3, .402, .446 | CONTROL ROOM MANAGEMENT/HUMAN FACTORS |
| 93c | 02/01/10 | 195.446 | CORRECTION |
| 94 | 10/01/10 | | PERIODIC UPDATES OF REGULATORY REFERENCES TO TECHNICAL STANDARDS AND MISCELLANEOUS EDITS |
| 95 | 11/26/2010 | 195.48, 49, 52, 54, 58, 62, 63, 64, | UPDATES TO PIPELINE AND LIQUEFIED NATURAL GAS REPORTING REQUIREMENTS |
| 96 | 05/05/11 | 195.1, 12, 48 | APPLYING SAFETY REGULATIONS TO ALL RURAL ONSHORE HAZARDOUS LIQUID LOW-STRESS LINES |
| 96c | 07/21/11 | 195.12 | APPLYING SAFETY REGULATIONS TO ALL RURAL ONSHORE HAZARDOUS LIQUID LOW-STRESS LINES, CORRECTIONI |
| 97 | 6/16/11 | 195.446 | CONTROL ROOM MANAGEMENT/HUMAN FACTORS |

*OPS quit numbering their new amendments for a while. For the purposes of tracking, T&Q is maintaining a numbering system.

# PART 195 – TRANSPORTATION OF OF HAZARDOUS LIQUIDS BY PIPELINE

## Subpart A–General



## Subpart B—Annual, Accident, and Safety-Related Condition Reporting



## Subpart C–Design Requirements

# PART 195 – TRANSPORTATION OF OF HAZARDOUS LIQUIDS BY PIPELINE

**Subpart D–Construction**



**Subpart E–Pressure Testing**



**Subpart F–Operation and Maintenance**

**Appendix B**—Risk-Based Alternative to Pressure Testing Older Hazardous Liquid and Carbon Dioxide Pipelines

**Appendix C to Part 195**–Guidance for Implementation of Integrity Management Program

**Authority:** 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60116, 60118; and 60137 ;and 49 CFR 1.53.

[50 FR 45733, Nov. 1, 1985 as amended by Amdt. 195-70, 65 FR 75378; Amdt. 195-71, 65 FR 80530, Dec. 21, 2000; Amdt. 195-72, 66 FR 43523, Aug. 20, 2001; Amdt. 195-73, 66 FR 66993, Dec. 27, 2002; Amdt. 195-80, 69 FR 537, Jan. 6, 2004; Amdt. 195-85, 70 FR 61571, Oct. 25, 2005; Amdt. 195-[89], 73 FR 31634, June 3, 2008] ; Amdt. 195-94, 75 FR 48593, August 11, 2010]

# PART 195 – TRANSPORTATION OF OF HAZARDOUS LIQUIDS BY PIPELINE

## Subpart A–General

### §195.0 Scope.

This part prescribes safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids or carbon dioxide.

[Amdt. 195-22, 46 FR 38357, July 27, 1981 as amended by Amdt. 195-45, 56 FR 26922, June 12, 1991]

### §195.1 Which pipelines are covered by this part?

(a) *Covered*. Except for the pipelines listed in paragraph (b) of this section, this part applies to pipeline facilities and the transportation of hazardous liquids or carbon dioxide associated with those facilities in or affecting interstate or foreign commerce, including pipeline facilities on the Outer Continental Shelf (OCS). This includes:

(1) Any pipeline that transports a highly volatile liquid (HVL);

(2) Transportation through any pipeline, other than a gathering line, that has a maximum operating pressure (MOP) greater than 20-percent of the specified minimum yield strength;

(3) Any pipeline segment that crosses a waterway currently used for commercial navigation;

(4) Transportation of petroleum in any of the following onshore gathering lines:

(i) A pipeline located in a non-rural area;

(ii) To the extent provided in §195.11, a regulated rural gathering line defined in §195.11; or

(iii) To the extent provided in §195.413, a pipeline located in an inlet of the Gulf of Mexico.

(5) Transportation of a hazardous liquid or carbon dioxide through a low-stress pipeline or segment of pipeline that:

(i) Is in a non-rural area; or

(ii) Meets the criteria defined in §195.12(a).

(6) For purposes of the reporting requirements in subpart B, a rural low-stress pipeline of any diameter.

(b) *Excepted*. This part does not apply to any of the following:

(1) Transportation of a hazardous liquid transported in a gaseous state;

(2) Transportation of a hazardous liquid through a pipeline by gravity;

(3) A pipeline subject to safety regulations of the U.S. Coast Guard;

(4) A low-stress pipeline that serves refining, manufacturing, or truck, rail, or vessel terminal facilities, if the pipeline is less than one mile long (measured outside facility grounds) and does not cross an offshore area or a waterway currently used for commercial navigation;

(5) Transportation of hazardous liquid or carbon dioxide in an offshore pipeline in State waters where the pipeline is located upstream from the outlet flange of the following farthest downstream facility: The facility where hydrocarbons or carbon dioxide are produced or the facility where produced hydrocarbons or carbon dioxide are first separated, dehydrated, or otherwise processed;

(6) Transportation of hazardous liquid or carbon dioxide in a pipeline on the OCS where the pipeline is located upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator;

(7) A pipeline segment upstream (generally seaward) of the last valve on the last production facility on the OCS where a pipeline on the OCS is producer-operated and crosses into State waters without first

connecting to a transporting operator's facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. A producing operator of a segment falling within this exception may petition the Administrator, under §190.9 of this chapter, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance;

(8) Transportation of a hazardous liquid or carbon dioxide through onshore production (including flow lines), refining, or manufacturing facilities or storage or in-plant piping systems associated with such facilities;

(9) Transportation of a hazardous liquid or carbon dioxide:

(i) By vessel, aircraft, tank truck, tank car, or other non-pipeline mode of transportation; or

(ii) Through facilities located on the grounds of a materials transportation terminal if the facilities are used exclusively to transfer hazardous liquid or carbon dioxide between non-pipeline modes of transportation or between a non-pipeline mode and a pipeline. These facilities do not include any device and associated piping that are necessary to control pressure in the pipeline under §195.406(b); or

(10) Transportation of carbon dioxide downstream from the applicable following point:

(i) The inlet of a compressor used in the injection of carbon dioxide for oil recovery operations, or the point where recycled carbon dioxide enters the injection system, whichever is farther upstream; or

(ii) The connection of the first branch pipeline in the production field where the pipeline transports carbon dioxide to an injection well or to a header or manifold from which a pipeline branches to an injection well.

(c) *Breakout tanks*. Breakout tanks subject to this part must comply with requirements that apply specifically to breakout tanks and, to the extent applicable, with requirements that apply to pipeline systems and pipeline facilities. If a conflict exists between a requirement that applies specifically to breakout tanks and a requirement that applies to pipeline systems or pipeline facilities, the requirement that applies specifically to breakout tanks prevails. Anhydrous ammonia breakout tanks need not comply with Sec. §195.132(b), 195.205(b), 195.242 (c) and (d), 195.264(b) and (e), 195.307, 195.428(c) and (d), and 195.432(b) and (c).

(a) *Covered*. Except for the pipelines listed in paragraph (b) of this Section, this Part applies to pipeline facilities and the transportation of hazardous liquids or carbon dioxide associated with those facilities in or affecting interstate or foreign commerce, including pipeline facilities on the Outer Continental Shelf (OCS). Covered pipelines include, but are not limited to:

(1) Any pipeline that transports a highly volatile liquid;

(2) Any pipeline segment that crosses a waterway currently used for commercial navigation;

(3) Except for a gathering line not covered by paragraph (a)(4) of this Section, any pipeline located in a rural or non-rural area of any diameter regardless of operating pressure;

(4) Any of the following onshore gathering lines used for transportation of petroleum:

(i) A pipeline located in a non-rural area;

(ii) A regulated rural gathering line as provided in §195.11; or

(iii) A pipeline located in an inlet of the Gulf of Mexico as provided in §195.413.

(b) *Excepted*. This Part does not apply to any of the following:

(1) Transportation of a hazardous liquid transported in a gaseous state;

(2) Transportation of a hazardous liquid through a pipeline by gravity;

(3) Transportation of a hazardous liquid through any of the following low-stress pipelines:

(i) A pipeline subject to safety regulations of the U.S. Coast Guard; or

(ii) A pipeline that serves refining, manufacturing, or truck, rail, or vessel terminal facilities, if the pipeline is less than one mile long (measured outside facility grounds) and does not cross an offshore area or a waterway currently used for commercial navigation;

(4) Transportation of petroleum through an onshore rural gathering line that does not meet the definition of a "regulated rural gathering line" as provided in §195.11. This exception does not apply to gathering lines in the inlets of the Gulf of Mexico subject to §195.413;

(5) Transportation of hazardous liquid or carbon dioxide in an offshore pipeline in state waters where the pipeline is located upstream from the outlet flange of the following farthest downstream facility: The facility where hydrocarbons or carbon dioxide are produced or the facility where produced hydrocarbons or carbon dioxide are first separated, dehydrated, or otherwise processed;

(6) Transportation of hazardous liquid or carbon dioxide in a pipeline on the OCS where the pipeline is located upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator;

(7) A pipeline segment upstream (generally seaward) of the last valve on the last production facility on the OCS where a pipeline on the OCS is producer-operated and crosses into state waters without first connecting to a transporting operator's facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. A producing operator of a segment falling within this exception may petition the Administrator, under §190.9 of this chapter, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance;

(8) Transportation of hazardous liquid or carbon dioxide through onshore production (including flow lines), refining, or manufacturing facilities or storage or in-plant piping systems associated with such facilities;

(9) Transportation of hazardous liquid or carbon dioxide:

(i) By vessel, aircraft, tank truck, tank car, or other non-pipeline mode of transportation; or

(ii) Through facilities located on the grounds of a materials transportation terminal if the facilities are used exclusively to transfer hazardous liquid or carbon dioxide between non-pipeline modes of transportation or between a non-pipeline mode and a pipeline. These facilities do not include any device and associated piping that are necessary to control pressure in the pipeline under §195.406(b); or

(10) Transportation of carbon dioxide downstream from the applicable following point:

(i) The inlet of a compressor used in the injection of carbon dioxide for oil recovery operations, or the point where recycled carbon dioxide enters the injection system, whichever is farther upstream; or

(ii) The connection of the first branch pipeline in the production field where the pipeline transports carbon dioxide to an injection well or to a header or manifold

from which a pipeline branches to an injection well.

(c) *Breakout tanks*. Breakout tanks subject to this Part must comply with requirements that apply specifically to breakout tanks and, to the extent applicable, with requirements that apply to pipeline systems and pipeline facilities. If a conflict exists between a requirement that applies specifically to breakout tanks and a requirement that applies to pipeline systems or pipeline facilities, the requirement that applies specifically to breakout tanks prevails. Anhydrous ammonia breakout tanks need not comply with §§ 195.132(b), 195.205(b), 195.242(c) and (d), 195.264(b) and (e), 195.307, 195.428(c) and (d), and 195.432(b) and (c).

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-1, 35 FR 5332, Mar. 31, 1970; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-33, 50 FR 15895, Apr. 23, 1985; Amdt. 195-34, 50 FR 34470, Aug. 26, 1985; Amdt. 195-36, 52 FR 15005, Apr. 22, 1986; Amdt. 195-36C, 51 FR 20976, June 10, 1986; Amdt. 195-45, 56 FR 26922, June 12, 1991; Amdt. 195-47, 56 FR 63764, Dec. 5, 1991; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-53, 59 FR 35465, July 12, 1994; Amdt. 195-57, 62 FR 31364, June 9, 1997; Amdt. 195-57A, 62 FR 52511, Oct. 8, 1997; Amdt. 195-59, 62 FR 61692, Nov. 19, 1997; Amdt. 195-64, 63 FR 46692, Sep. 2, 1998; Amdt. 195-66, 64 FR 15926, April 2, 1999; Amdt. 195-78, 68 FR 46109, Aug. 5, 2003; 70 FR 11135, Mar. 8, 2005; Amdt. 195-[89], 73 FR 31634, June 3, 2008; Amdt. 195-96, 76 FR 25576, May 5, 2011]

**§195.2 Definitions.**

As used in this part–

***Abandoned*** means permanently removed from service.

***Administrator*** means the Administrator, Pipeline Hazardous Materials Safety Administration or his or her delegate.

***Alarm*** means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.

***Barrel*** means a unit of measurement equal to 42 U.S. standard gallons.

***Breakout tank*** means a tank used to (a) relieve surges in a hazardous liquid pipeline system or (b) receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline.

***Carbon dioxide*** means a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state.

***Component*** means any part of a pipeline which may be subjected to pump pressure including, but not limited to, pipe, valves, elbows, tees, flanges, and closures.

***Computation Pipeline Monitoring (CPM)*** means a software-based monitoring tool that alerts the pipeline dispatcher of a possible pipeline operating anomaly that may be indicative of a commodity release.

***Corrosive product*** means "corrosive material" as defined by §173.136 Class 8-Definitions of this chapter.

***Control room*** means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.

***Controller*** means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility.

***Exposed underwater pipeline*** means an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water.

***Flammable product*** means "flammable liquid" as defined by §173.120 Class 3-Definitions of this chapter.

***Gathering line*** means a pipeline 219.1 mm (8 5/8 in) or less nominal outside diameter that transports petroleum from a production facility.

***Gulf of Mexico and its inlets*** means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.

***Hazardous liquid*** means petroleum, petroleum products, or anhydrous ammonia.

***Hazard to navigation*** means, for the purpose of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.

***Highly volatile liquid*** or ***HVL*** means a hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 76 kPa (40 psia) at 37.8°C (100°F).

***In-plant piping systems*** means piping that is located on the grounds of a plant and used to transfer hazardous liquid or carbon dioxide between plant facilities or between plant facilities and a pipeline or other mode of transpor-tation, not including any device and associated piping that are necessary to control pressure in the pipeline under §195.406(b).

***Interstate pipeline*** means a pipeline or that part of a pipeline that is used in the transportation of hazardous liquids or carbon dioxide in interstate or foreign commerce.

***Intrastate pipeline*** means a pipeline or that part of a pipeline to which this part applies that is not an interstate pipeline.

***Line section*** means a continuous run of pipe between adjacent pressure pump stations, between a pressure pump station and terminal or breakout tanks, between a pressure pump station and a block valve, or between adjacent block valves.

***Low stress pipeline*** means a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe.

***Maximum operating pressure (MOP)*** means the maximum pressure at which a pipeline or segment of a pipeline may be normally operated under this part.

***Nominal wall thickness*** means the wall thickness listed in the pipe specifications.

***Offshore*** means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

***Operator*** means a person who owns or operates pipeline facilities.

***Outer Continental Shelf*** means all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

***Person*** means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.

***Petroleum*** means crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas.

***Petroleum product*** means flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds.

***Pipe*** or ***line pipe*** means a tube, usually cylindrical, through which a hazardous liquid or carbon dioxide flows from one point to another.

***Pipeline*** or ***pipeline system*** means all parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.

***Pipeline facility*** means new and existing pipe, rights-of-way, and any equipment, facility, or building used in the transportation of hazardous liquids or carbon dioxide.

***Production facility*** means piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum or carbon dioxide, or associated storage or measurement. (To be a production facility under this definition, piping or equipment must be used in the process of extracting petroleum or carbon dioxide from the ground or from facilities where $CO_2$ is produced, and preparing it for transportation by pipeline. This includes piping between treatment plants which extract carbon dioxide, and facilities utilized for the injection of carbon dioxide for recovery operations.)

***Rural area*** means outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, or community development.

***Specified minimum yield strength*** means the minimum yield strength, expressed in p.s.i. (kPa ) gage, prescribed by the specification under which the material is purchased from the manufacturer.

***Stress level*** means the level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.

***Supervisory Control and Data Acquisition (SCADA) system*** means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

***Surge pressure*** means pressure produced by a change in velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream.

***Toxic product*** means "poisonous material" as defined by 173.132 Class 6, Division 6.1-Definitions of this chapter.

***Unusually sensitive area (USA)*** means a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release, as identified under §195.6.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-2, 35 FR 17183, Nov. 7, 1970; Amdt 195-5, 38 FR 2977, Jan. 31, 1973; Amdt. 195-15, 44 FR 41197, July 16, 1979; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-33, 50 FR 15895, Apr. 23, 1985; Amdt. 195-33C, 50 FR 38659, Sept. 24, 1985; Amdt. 195-36, 51 FR 15005, Apr. 22, 1986; Amdt. 195-45, 56 FR 26922, June 12, 1991; Amdt. 195-47, 56 FR 63764, Dec. 5, 1991; Amdt. 195-50, 59 FR 17275, Apr. 12, 1994; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-53, 59 FR 35465, July 12, 1994; Amdt. 195-59, 62 FR 61692, Nov. 19, 1997; Amdt. 195-62, 63 FR 36373, July 6, 1998; Amdt. 195-63, 63 FR 37500, July 13, 1998; Amdt. 195-69, 65 FR 54440, Sept. 8, 2000, Amdt. 915-71, 65 FR 80530, Dec. 21, 2000; Amdt. 195-77, 68 FR 11748, Mar. 12, 2003; Amdt. 195-81, 69 FR 32886, June 14, 2004; Amdt. 195-82, 69 FR 48400, Aug. 10, 2004; 70 FR 11135, Mar. 8, 2005: Amdt. 195-93, 74 FR 63310, Dec. 3, 2009]

**§195.3 Matter incorporated by reference in whole or in part.**

(a) Any document or portion thereof incorporated by reference in this part is included in this part as though it were printed in full. When only a portion of a document is referenced, then this part incorporates only that referenced portion of the document and the reminder is not incorporated. Applicable editions are listed in paragraph (c) of this section in parentheses following the title of the referenced material. Earlier editions listed in previous editions of this section may be used for components manufactured, designed, or installed in accordance with those earlier editions at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR for a listing of the earlier editions.

(b) All incorporated materials are available for inspection in the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, 1200 New Jersey Avenue, SE, Washington, DC, 20590-0001 or at the National Archives and Records Administration (NARA). For

information on the availability of this material at NARA, call 202-741-6030 or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html*. These materials have been approved for incorporation by reference by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. In addition, materials incorporated by reference are available as follows:

1. Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, Houston, TX 77098.

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

3. ASME International (ASME), Three Park Avenue, New York, NY 10016-5990.

4. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NE., Vienna, VA 22180.

5. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.

6. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101.

7. NACE International, 1440 South Creek Drive, Houston, TX 77084.

(c) The full titles of publications incorporated by reference wholly or partially in this part are as follows. Numbers in parentheses indicate applicable editions:

| Source and name of referenced material | 49 CFR reference |
|---|---|
| A. Pipeline Research Council International, Inc. (PRCI):<br>(1) AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 22, 1989). The RSTRENG program may be used for calculating remaining strength. | §195.452(h)(4)(B). 195.452(h)(4)(iii)(D); 195.587. |
| B. American Petroleum Institute (API):<br>(1) ANSI/API Specification 5L/ISO 3183 "Specification for Line Pipe" (44th edition, October 2007, including errata (January 2009) and addendum (February 2009)). (43rd edition and errata, 2004, and 44th edition, 2007).API Specification 5L "Specification for Line Pipe" (43rd edition and errata, 2004)(42nd edition, 2000). | §§ 195.106(b)(1)(i); 195.106(e). |
| (2) API Recommended Practice 5L1, "Recommended Practice for Railroad Transportation of Line Pipe" (6th edition, July 2002). | § 195.207(a). |
| (3) API Recommended Practice 5LW, "Transportation of Line Pipe on Barges and Marine Vessels" (2nd edition, December 1996, effective March 1, 1997). | § 195.207(b). |
| (42) ANSI/API Specification 6D "Specification for Pipeline Valves (23rd edition, April 2008, effective October 1, 2008) and errata 3 (includes 1 & 2 (2009). (Gate, Plug, Ball, and Check Valves)" (22nd edition, January 2002). | §195.116(d). |
| (53) API Specification 12F "Specification for Shop Welded Tanks for Storage of Production Liquids" (11th edition, November 1, | §§195.132(b)(1); 195.205(b)(2); |

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| 1994, reaffirmed 2000, errata, February 2007). | 195.264(b)(1); 195.264(e)(1); 195.307(a); 195.565; 195.579(d). |
| (64) API 510 "Pressure Vessel Inspection Code: In-ServiceMaintenance Inspection, Rating, Repair, and Alteration" (98th edition, June 20061997, and Addenda 1 through 4). | §§ 195.205(b)(3); 195.432(c). |
| (75) API Standard 620 "Design and Construction of Large, Welded, Low-Pressure Storage Tanks" (1110th edition,February 20082 including Addendum 1 March 2009). | §§ 195.132(b)(2); 195.205(b)(2); 195.264(b)(1); 195.264(e)(3); 195.307(b). |
| (86) API Standard 650 "Welded Steel Tanks for Oil Storage" (11th edition, June 2007, addendum 1, November 200810th edition, 1998 including Addenda 1-3). | §§ 195.132(b)(3); 195.205(b)(1); 195.264(b)(1); 195.264(e)(2); 195.307(c); 195.307(d); 195.565; 195.579(d). |
| (97) ANSI/API Recommended Practice 651 "Cathodic Protection of Aboveground Petroleum Storage Tanks" (3rd2nd edition, January 2007December 1997). | §§ 195.565; 195.579(d). |
| (108) ANSI/API Recommended Practice 652 "Lining of Aboveground Petroleum Storage Tank Bottoms" (3rd2nd edition, October 2005December 1997). | §195.579(d). |
| (119) API Standard 653 "Tank Inspection, Repair, Alteration, and Reconstruction" (3rd edition, December 2001 includesincluding Addendum 1,(September 2003). addendum 2 (November 2005), addendum 3 (February 2008), and errata (April 2008)) | §§ 195.205(b)(1); 195.432(b). |
| (1210) API Standard 1104 "Welding of Pipelines and Related Facilities" (2019th edition October 2005, errata/addendum (July 2007), and errata 2 December 2008)).1999, including errata October 31, 2001; and 20th edition 2007, including errata 2008).API 1104 "Welding of Pipelines and Related Facilities" (19th edition, 1999 including plus its October 31, 2001 errata). | §§ 195.222(a); 195.228(b); 195.214(a). |
| (1311) API Recommended Practice 1130, "Computational Pipeline Monitoring for Liquids: Pipeline Segment" (3rd edition, September 2007).API 1130 "Computational Pipeline Monitoring" (2nd edition, 2002). | §§ 195.134; 195.444. |
| (14) API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators" (1st edition, December 2003). | §§ 195.440(a); 195.440(b); 195.440(c). |
| (15) API Recommended Practice 1165, "Recommended Practice for Pipeline SCADA Displays," (API RP 1165) First Edition (January 2007). | § 195.446(c)(1). |
| (1612) API Standard 2000 "Venting Atmospheric and Low-Pressure Storage Tanks" Nonrefrigerated and Refrigerated" (5th | §§ 195.264(e)(2); 195.264(e)(3). |

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| edition, April 1998, errata, November 15, 1999). | |
| (1713) API Recommended Practice 2003 "Protection Against Ignitions Arising out of Static, Lightning, and Stray Currents" (76th edition, January 20081998). | §195.405(a). |
| (1814) API Publication 2026 "Safe Access/Egress Involving Floating Roofs of Storage Tanks in Petroleum Service" (2nd edition, April 1998, reaffirmed June 2006). | §195.405(b). |
| (1915) API Recommended Practice 2350 "Overfill Protection for Storage Tanks In Petroleum Facilities" (3rd2nd edition, January 20051996). | §195.428(c). |
| (2016) API Standard 2510 "Design and Construction of LPG Installations"(8th edition, 2001). | §§ 195.132(b)(3); 195.205(b)(3); 195.264(b)(2); 195.264(e)(4); 195.307(e); 195.428(c); 195.432(c). |
| (17) API Recommended Practice 1162 "Public Awareness Programs for Pipeline Operators," (1st edition, December 2003) | §§ 195.440(a); 195.440(b); 195.440(c) |
| (18) API Recommended Practice 1165 "Recommended Practice for Pipeline SCADA Displays," (API RP 1165) First Edition (January 2007). | §195.446(c)(1). |
| (2119) API Recommended Practice 1168 "Pipeline Control Room Management," (API RP 1168) First Edition (September 2008). | §195.446(c)(5),(f)(1). |
| C. ASME International (ASME):<br>(1) ASME/ANSI B16.9-20073 (February 2004) "Factory-Made Wrought Steel Buttwelding Fittings" (December 7, 2007). | §195.118(a). |
| (2) ASME/ANSI B31.4-20062 (October 2002) "Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids" (October 20, 2006). | §195.452(h)(4)(i). |
| (3) ASME/ANSI B31G-1991 (Reaffirmed; 2004) "Manual for Determining the Remaining Strength of Corroded Pipelines" . | §§ 195.452(h)(4)(i)(B); 195.452(h)(4)(iii)(D). |
| (4) ASME/ANSI B31.8-20073 (February 2004) "Gas Transmission and Distribution Piping Systems" (November 30, 2007). | §§ 195.5(a)(1)(i); 195.406(a)(1)(i). |
| (5) 2007 ASME Boiler and Pressure vessel Code, Section VIII, Division 1 "Rules for Construction of Pressure Vessels," (20074 edition, including addenda through July 1, 20075). | §§ 195.124; 195.307(e). |
| (6) 2007 ASME Boiler and Pressure Vessel Code, Section VIII, Division 2 "Alternate Rules for Construction offor Pressure Vessels" (20074 edition,including addenda through July 1, 20075). | §195.307(e). |
| (7) 2007 ASME Boiler and Pressure vessel Code, Section IX "Welding and Brazing Qualifications," (2004 edition, including addenda through July 1, 2005).Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators," (2007 edition, July 1, 2007). | §195.222(a). |

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| D. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):<br>(1) MSS SP-75-2004 "Specification for High Test Wrought Butt Welding Fittings" .<br>(2) [Reserved]. | §195.118(a). |
| E. American Society for Testing and Materials (ASTM):<br>(1) ASTM Designation: A53/A53M-07,04a (2004) "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated Welded and Seamless" (September 1, 2007). | §195.106(e). |
| (2) ASTMDesignation: A106/A106M-08,04b (2004) "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (July 15, 2008). | §195.106(e). |
| (3) ASTM Designation: A 333/A 333M-05, "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service" . | §195.106(e). |
| (4) ASTM Designation: A 381-96 (Reapproved 20051), "Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems" (October 1, 2005). | §195.106(e). |
| (5) ASTM Designation: A 671-06,04 (2004) "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures" (May 1, 2006). | §195.106(e). |
| (6) ASTM Designation: A 672-0896 (Reapproved 2001) "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (May 1, 2008). | §195.106(e). |
| (7) ASTM Designation: A 691-98 (Reapproved 20072), "Standard Specification for Carbon and Alloy Steel Pipe Electric-Fusion-Welded for High-Pressure Service at High Temperatures" . | §195.106(e). |
| F. National Fire Protection Association (NFPA):<br>(1) NFPA 30(2003) "Flammable and Combustible Liquids Code" (2008 edition, approved August 15, 2007).<br>(2) [Reserved]..... | §195.264(b)(1). |
| G. NACE International (NACE):<br>(1) NACE SP0169-2007, Standard Practice, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" (reaffirmed March 15, 2007).Standard RSP0169-20072 "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" . | §§195.571; 195.573(a)(2) |
| (2) NACE SP0502-2008, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology" (reaffirmed March 20, 2008).Standard RP0502-2002 "Pipeline External Corrosion Direct Assessment Methodology" (2002). | §195.588 |

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-5, 38 FR 2977, Jan. 31, 1973; Amdt. 195-9, 41 FR 13590, Mar. 31, 1976; Amdt. 195-14, 43 FR 18553, May 1, 1978; Amdt. 195-21, 46 FR 10157, Feb. 2, 1981; Amdt. 195-22, 46 FR 38357, July 27, 1981;

Amdt. 195-32, 49 FR 36859, Sep. 20, 1984; Amdt. 195-37, 51 FR 15333, Apr. 23. 1986; Amdt. 195-40, 54 FR 5625, Feb. 6. 1989; Amdt. 195-41, 54 FR 22781, July 3, 1989; Amdt. 195-43, 54 FR 32344, Aug. 7, 1989; Amdt. 195-45, 56 FR 26922, June 12, 1991; Amdt. 195-48, 58 FR 14519, Mar. 18, 1993; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-56, 61 FR 26121, May, 24, 1996; Amdt. 195-56A, 61 FR 36825, July 15, 1996; Amdt. 195-61, 63 FR 7721, Feb. 17, 1998; Amdt. 195-62, 63 FR 36373, July 6, 1998; Amdt. 195-66, 64 FR 15926, April 2, 1999; Amdt. 195-66A, 65 FR 4770, Feb. 1, 2000; Amdt. 195-73, 66 FR 66993, Dec. 27, 2002; Amdt. 195-81, 69 FR 32886, June 14, 2004; Amdt. 195-84, 70 FR 28833, May 19, 2005; Amdt. 195-85, 70 FR 61571, Oct. 25, 2005; Amdt. 195-86, 71 FR 33402, June 9, 2006; Amdt. 195-[88], 73 FR 16562, Mar. 28, 2008; Amdt. 195-[90], 74 FR 2889, January 16, 2009; Amdt. 195-[91], 74 FR 17099, April 14, 2009; Amdt. 195-93, 74 FR 63310, Dec. 3, 2009] Amdt. 195-94, 75 FR 48593, August 11, 2010]

**§195.4 Compatibility necessary for transportation of hazardous liquids or carbon dioxide.**

No person may transport any hazardous liquid or carbon dioxide unless the hazardous liquid or carbon dioxide is chemically compatible with both the pipeline, including all components, and any other commodity that it may come into contact with while in the pipeline.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-45, 56 FR 26922, June 12, 1991]

**§195.5 Conversion to service subject to this part.**

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to accomplish the following:

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in satisfactory condition for safe operation. If one or more of the variables necessary to verify the design pressure under §195.106 or to perform the testing under paragraph (a) (4) of this section is unknown, the design pressure may be verified and the maximum operating pressure determine by-

(i) Testing the pipeline in accordance with ASME B31.8, Appendix N, to produce a stress equal to the yield strength; and

(ii) Applying, to not more than 80 percent of the first pressure that produces a yielding, the design factor F in §195.106(a) and the appropriate factors in §195.106(e).

(2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.

(3) All known unsafe defects and conditions must be corrected in accordance with this part.

(4) The pipeline must be tested in accordance with subpart E of this part to substantiate the maximum operating pressure permitted by §195.406.

(b) A pipeline that qualifies for use under this section need not comply with the corrosion control requirements of subpart H

of this part until 12 months after it is placed into service, notwithstanding any previous deadlines for compliance.

(c) Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section.

[Amdt. 195-13, 43 FR 6786, Feb. 16, 1979 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.6 Unusually Sensitive Areas (USAs).**

As used in this part, a USA means a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release.

(a) An USA drinking water resource is:

(1) The water intake for a Community Water System (CWS) or a Non-transient Non-community Water System (NTNCWS) that obtains its water supply primarily from a surface water source and does not have an adequate alternative drinking water source;

(2) The Source Water Protection Area (SWPA) for a CWS or a NTNCWS that obtains its water supply from a Class I or Class IIA aquifer and does not have an adequate alternative drinking water source. Where a state has not yet identified the SWPA, the Wellhead Protection Area (WHPA) will be used until the state has identified the SWPA; or

(3) The sole source aquifer recharge area where the sole source aquifer is a karst aquifer in nature.

(b) An USA ecological resource is:

(1) An area containing a critically imperiled species or ecological community;

(2) A multi-species assemblage area;

(3) A migratory waterbird concentration area;

(4) An area containing an imperiled species, threatened or endangered species, depleted marine mammal species, or an imperiled ecological community where the species or community is aquatic, aquatic dependent, or terrestrial with a limited range; or

(5) An area containing an imperiled species, threatened or endangered species, depleted marine mammal species, or imperiled ecological community where the species or community occurrence is considered to be one of the most viable, highest quality, or in the best condition, as identified by an element occurrence ranking (EORANK) of A (excellent quality) or B (good quality).

(c) As used in this part--

*Adequate Alternative Drinking Water Source* means a source of water that currently exists, can be used almost immediately with a minimal amount of effort and cost, involves no decline in water quality, and will meet the consumptive, hygiene, and fire fighting requirements of the existing population of impacted customers for at least one month for a surface water source of water and at least six months for a groundwater source.

*Aquatic or Aquatic Dependent Species or Community means* a species or community that primarily occurs in aquatic, marine, or wetland habitats, as well as species that may use terrestrial habitats during all or some portion of their life cycle, but that are still closely associated with or dependent upon aquatic, marine, or wetland habitats for some critical component or portion of their life-history (i.e.,

reproduction, rearing and development, feeding, etc).

*Class I Aquifer* means an aquifer that is surficial or shallow, permeable, and is highly vulnerable to contamination. Class I aquifers include:

(1) Unconsolidated Aquifers (Class Ia) that consist of surficial, unconsolidated, and permeable alluvial, terrace, outwash, beach, dune and other similar deposits. These aquifers generally contain layers of sand and gravel that, commonly, are interbedded to some degree with silt and clay. Not all Class Ia aquifers are important water-bearing units, but they are likely to be both permeable and vulnerable. The only natural protection of these aquifers is the thickness of the unsaturated zone and the presence of fine-grained material;

(2) Soluble and Fractured Bedrock Aquifers (Class Ib). Lithologies in this class include limestone, dolomite, and, locally, evaporitic units that contain documented karst features or solution channels, regardless of size. Generally these aquifers have a wide range of permeability. Also included in this class are sedimentary strata, and metamorphic and igneous (intrusive and extrusive) rocks that are significantly faulted, fractured, or jointed. In all cases groundwater movement is largely controlled by secondary openings. Well yields range widely, but the important feature is the potential for rapid vertical and lateral ground water movement along preferred pathways, which result in a high degree of vulnerability;

(3) Semiconsolidated Aquifers (Class Ic) that generally contain poorly to moderately indurated sand and gravel that is interbedded with clay and silt. This group is intermediate to the unconsolidated and consolidated end members. These systems are common in the Tertiary age rocks that are exposed throughout the Gulf and Atlantic coastal states. Semiconsolidated conditions also arise from the presence of intercalated clay and caliche within primarily unconsolidated to poorly consolidated units, such as occurs in parts of the High Plains Aquifer; or

(4) Covered Aquifers (Class Id) that are any Class I aquifer overlain by less than 50 feet of low permeability, unconsolidated material, such as glacial till, lacustrian, and loess deposits.

*Class IIa aquifer* means a Higher Yield Bedrock Aquifer that is consolidated and is moderately vulnerable to contamination. These aquifers generally consist of fairly permeable sandstone or conglomerate that contain lesser amounts of interbedded fine grained clastics (shale, siltstone, mudstone) and occasionally carbonate units. In general, well yields must exceed 50 gallons per minute to be included in this class. Local fracturing may contribute to the dominant primary porosity and permeability of these systems.

*Community Water System (CWS)* means a public water system that serves at least 15 service connections used by year-round residents of the area or regularly serves at least 25 year-round residents.

*Critically imperiled species or ecological community (habitat)* means an animal or plant species or an ecological community of extreme rarity, based on The Nature Conservancy's Global Conservation Status Rank. There are generally 5 or fewer occurrences, or very few remaining individuals (less than 1,000) or acres (less than 2,000). These species and ecological communities are extremely vulnerable to extinction due to some natural or man-made factor.

*Depleted marine mammal species* means a species that has been identified and is protected under the Marine Mammal Protection Act of 1972, as amended (MMPA) (16 U.S.C. 1361 et seq.). The term

"depleted" refers to marine mammal species that are listed as threatened or endangered, or are below their optimum sustainable populations (16 U.S.C. 1362). The term "marine mammal" means "any mammal which is morphologically adapted to the marine environment (including sea otters and members of the orders Sirenia, Pinnipedia, and Cetacea), or primarily inhabits the marine environment (such as the polar bear)" (16 U.S.C. 1362). The order Sirenia includes manatees, the order Pinnipedia includes seals, sea lions, and walruses, and the order Cetacea includes dolphins, porpoises, and whales.

*Ecological community* means an interacting assemblage of plants and animals that recur under similar environmental conditions across the landscape.

*Element occurrence rank (EORANK)* means the condition or viability of a species or ecological community occurrence, based on a population's size, condition, and landscape context. EORANKs are assigned by the Natural Heritage Programs. An EORANK of A means an excellent quality and an EORANK of B means good quality.

*Imperiled species or ecological community (habitat)* means a rare species or ecological community, based on The Nature Conservancy's Global Conservation Status Rank. There are generally 6 to 20 occurrences, or few remaining individuals (1,000 to 3,000) or acres (2,000 to 10,000). These species and ecological communities are vulnerable to extinction due to some natural or man-made factor.

*Karst aquifer* means an aquifer that is composed of limestone or dolomite where the porosity is derived from connected solution cavities. Karst aquifers are often cavernous with high rates of flow.

*Migratory waterbird concentration* area means a designated Ramsar site or a Western Hemisphere Shorebird Reserve Network site.

*Multi-species assemblage area* means an area where three or more different critically imperiled or imperiled species or ecological communities, threatened or endangered species, depleted marine mammals, or migratory waterbird concentrations co-occur.

*Non-transient Non-community Water System (NTNCWS)* means a public water system that regularly serves at least 25 of the same persons over six months per year. Examples of these systems include schools, factories, and hospitals that have their own water supplies.

*Public Water System (PWS)* means a system that provides the public water for human consumption through pipes or other constructed conveyances, if such system has at least 15 service connections or regularly serves an average of at least 25 individuals daily at least 60 days out of the year. These systems include the sources of the water supplies--i.e., surface or ground. PWS can be community, non-transient non-community, or transient non-community systems.

*Ramsar site* means a site that has been designated under The Convention on Wetlands of International Importance Especially as Waterfowl Habitat program. Ramsar sites are globally critical wetland areas that support migratory waterfowl. These include wetland areas that regularly support 20,000 waterfowl; wetland areas that regularly support substantial numbers of individuals from particular groups of waterfowl, indicative of wetland values, productivity, or diversity; and wetland areas that regularly support 1% of the individuals in a population of one species or subspecies of waterfowl.

*Sole source aquifer (SSA)* means an area designated by the U.S. Environmental

Protection Agency under the Sole Source Aquifer program as the "sole or principal" source of drinking water for an area. Such designations are made if the aquifer's ground water supplies 50% or more of the drinking water for an area, and if that aquifer were to become contaminated, it would pose a public health hazard. A sole source aquifer that is karst in nature is one composed of limestone where the porosity is derived from connected solution cavities. They are often cavernous, with high rates of flow.

*Source Water Protection Area (SWPA)* means the area delineated by the state for a public water supply system (PWS) or including numerous PWSs, whether the source is ground water or surface water or both, as part of the state source water assessment program (SWAP) approved by EPA under section 1453 of the Safe Drinking Water Act.

*Species* means species, subspecies, population stocks, or distinct vertebrate populations.

*Terrestrial ecological community with a limited range* means a non-aquatic or non-aquatic dependent ecological community that covers less than five (5) acres.

*Terrestrial species with a limited range* means a non-aquatic or non-aquatic dependent animal or plant species that has a range of no more than five (5) acres.

*Threatened and endangered species (T&E)* means an animal or plant species that has been listed and is protected under the Endangered Species Act of 1973, as amended (ESA73) (16 U.S.C. 1531 et seq.). "Endangered species" is defined as "any species which is in danger of extinction throughout all or a significant portion of its range" (16 U.S.C. 1532). "Threatened species" is defined as "any species which is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range" (16 U.S.C. 1532).

*Transient Non-community Water System (TNCWS*) means a public water system that does not regularly serve at least 25 of the same persons over six months per year. This type of water system serves a transient population found at rest stops, campgrounds, restaurants, and parks with their own source of water.

*Wellhead Protection Area (WHPA)* means the surface and subsurface area surrounding a well or well field that supplies a public water system through which contaminants are likely to pass and eventually reach the water well or well field.

*Western Hemisphere Shorebird Reserve Network (WHSRN) site* means an area that contains migratory shorebird concentrations and has been designated as a hemispheric reserve, international reserve, regional reserve, or endangered species reserve. Hemispheric reserves host at least 500,000 shorebirds annually or 30% of a species flyway population. International reserves host 100,000 shorebirds annually or 15% of a species flyway population. Regional reserves host 20,000 shorebirds annually or 5% of a species flyway population. Endangered species reserves are critical to the survival of endangered species and no minimum number of birds is required.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-1, 35 FR 5332, Mar. 31, 1970; Amdt. 195-5, 38 FR 2977, Jan. 31, 1973; Amdt. 195-71, 65 FR 80530, Dec. 21, 2000]

### §195.8 Transportation of hazardous liquid or carbon dioxide in pipelines constructed with other than steel pipe.

No person may transport any hazardous liquid or carbon dioxide through a pipe that

is constructed after October 1, 1970, for hazardous liquids or after July 12, 1991 for carbon dioxide of material other than steel unless the person has notified the Administrator in writing at least 90 days before the transportation is to begin. The notice must state whether carbon dioxide or a hazardous liquid is to be transported and the chemical name, common name, properties, and characteristics of the hazardous liquid to be transported and the material used in construction of the pipeline. If the Administrator determines that the transportation of the hazardous liquid or carbon dioxide in the manner proposed would be unduly hazardous, he will, within 90 days after receipt of the notice, order the person that gave the notice, in writing, not to transport the hazardous liquid or carbon dioxide in the proposed manner until further notice.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-1, 35 FR 5332, Mar. 31, 1970; Amdt. 195-2, 35 FR 17183, Nov. 7, 1970; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-45, 56 FR 26922, June 12, 1991, Amdt. 195-50, 59 FR 17275, Apr. 12, 1994]

### §195.9 Outer continental shelf pipelines.

Operators of transportation pipelines on the Outer Continental Shelf must identify on all their respective pipelines the specific points at which operating responsibility transfers to a producing operator. For those instances in which the transfer points are not identifiable by a durable marking, each operator will have until September 15, 1998 to identify the transfer points. If it is not practicable to durably mark a transfer point and the transfer point is located above water, the operator must depict the transfer point on a schematic maintained near the transfer point. If a transfer point is located subsea, the operator must identify the transfer point on a schematic which must be maintained at the nearest upstream facility and provided to PHMSA upon request. For those cases in which adjoining operators have not agreed on a transfer point by September 15, 1998 the Regional Director and the MMS Regional Supervisor will make a joint determination of the transfer point.

[Amdt. 195-59, 62 FR 61692, Nov. 19, 1997; 70 FR 11135, Mar. 8, 2005]

### §195.10 Responsibility of operator for compliance with this part.

An operator may make arrangements with another person for the performance of any action required by this part. However, the operator is not thereby relieved from the responsibility for compliance with any requirement of this part.

[Part 195 - Org., Oct. 4, 1969]

### §195.11 What is a regulated rural gathering line and what requirements apply?

Each operator of a regulated rural gathering line, as defined in paragraph (a) of this section, must comply with the safety requirements described in paragraph (b) of this section.

(a) *Definition*. As used in this section, a regulated rural gathering line means an onshore gathering line in a rural area that meets all of the following criteria—

(1) Has a nominal diameter from 6⅝ inches (168 mm) to 8⅝ inches (219.1 mm);

(2) Is located in or within one-quarter mile (.40 km) of an unusually sensitive area as defined in §195.6; and

(3) Operates at a maximum pressure established under §195.406 corresponding to—

(i) A stress level greater than 20-percent of the specified minimum yield strength of the line pipe; or

(ii) If the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure of more than 125 psi (861 kPa) gage.

(b) *Safety requirements*. Each operator must prepare, follow, and maintain written procedures to carry out the requirements of this section. Except for the requirements in paragraphs (b)(2), (b)(3), (b)(9) and (b)(10) of this section, the safety requirements apply to all materials of construction.

(1) Identify all segments of pipeline meeting the criteria in paragraph (a) of this section before April 3, 2009.

(2) For steel pipelines constructed, replaced, relocated, or otherwise changed after July 3, 2009, design, install, construct, initially inspect, and initially test the pipeline in compliance with this part, unless the pipeline is converted under §195.5.

(3) For non-steel pipelines constructed after July 3, 2009, notify the Administrator according to §195.8.

(4) Beginning no later than January 3, 2009, comply with the reporting requirements in subpart B of this part.

(5) Establish the maximum operating pressure of the pipeline according to §195.406 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009.

(6) Install line markers according to §195.410 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009. Continue to maintain line markers in compliance with §195.410.

(7) Establish a continuing public education program in compliance with §195.440 before transportation begins, or if the pipeline exists on July 3, 2008, before January 3, 2010. Continue to carry out such program in compliance with §195.440.

(8) Establish a damage prevention program in compliance with §195.442 before transportation begins, or if the pipeline exists on July 3, 2008, before July 3, 2009. Continue to carry out such program in compliance with §195.442.

(9) For steel pipelines, comply with subpart H of this part, except corrosion control is not required for pipelines existing on July 3, 2008 before July 3, 2011.

(10) For steel pipelines, establish and follow a comprehensive and effective program to continuously identify operating conditions that could contribute to internal corrosion. The program must include measures to prevent and mitigate internal corrosion, such as cleaning the pipeline and using inhibitors. This program must be established before transportation begins or if the pipeline exists on July 3, 2008, before July 3, 2009.

(11) To comply with the Operator Qualification program requirements in subpart G of this part, have a written description of the processes used to carry out the requirements in §195.505 to determine the qualification of persons performing operations and maintenance tasks. These processes must be established before transportation begins or if the pipeline exists on July 3, 2008, before July 3, 2009.

(c) *New unusually sensitive areas*. If, after July 3, 2008, a new unusually sensitive area is identified and a segment of pipeline becomes regulated as a result, except for the requirements of paragraphs (b)(9) and (b)(10) of this section, the operator must implement the requirements in paragraphs (b)(2) through (b)(11) of this section for the

affected segment within 6 months of identification. For steel pipelines, comply with the deadlines in paragraph (b)(9) and (b)(10).

(d) *Record Retention.* An operator must maintain records demonstrating compliance with each requirement according to the following schedule.

(1) An operator must maintain the segment identification records required in paragraph (b)(1) of this section and the records required to comply with (b)(10) of this section, for the life of the pipe.

(2) An operator must maintain the records necessary to demonstrate compliance with each requirement in paragraphs (b)(2) through (b)(9), and (b)(11) of this section according to the record retention requirements of the referenced section or subpart.

[Amdt. 195-[89], 73 FR 31634, June 3, 2008]

**§195.12 What requirements apply to low-stress pipelines in rural areas?**

(a) *General.* This section does not apply to a rural low-stress pipeline regulated under this part as a low-stress pipeline that crosses a waterway currently used for commercial navigation. An operator of a rural low-stress pipeline meeting the following criteria must comply with the safety requirements described in paragraph (b) of this section. The pipeline:

(1) Has a nominal diameter of 8⅝ inches (219.1 mm) or more;

(2) Is located in or within a half mile (.80 km) of an unusually sensitive area (USA) as defined in §195.6; and

(3) Operates at a maximum pressure established under §195.406 corresponding to:

(i) A stress level equal to or less than 20-percent of the specified minimum yield strength of the line pipe; or

(ii) If the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure equal to or less than 125 psi (861 kPa) gage.

(b) *Requirements.* An operator of a pipeline meeting the criteria in paragraph (a) of this section must comply with the following safety requirements and compliance deadlines.

(1) Identify all segments of pipeline meeting the criteria in paragraph (a) of this section before April 3, 2009.

(2) Beginning no later than January 3, 2009, comply with the reporting requirements of subpart B for the identified segments.

(3)(i) Establish a written program in compliance with §195.452 before July 3, 2009, to assure the integrity of the low-stress pipeline segments. Continue to carry out such program in compliance with §195.452.

(ii) To carry out the integrity management requirements in §195.452, an operator may conduct a determination per §195.452(a) in lieu of the half mile buffer.

(iii) Complete the baseline assessment of all segments in accordance with §195.452(c) before July 3, 2015, and complete at least 50-percent of the assessments, beginning with the highest risk pipe, before January 3, 2012.

(4) Comply with all other safety requirements of this part, except subpart H, before July 3, 2009. Comply with subpart H before July 3, 2011.

(c) *Economic compliance burden.* (1) An operator may notify PHMSA in accordance with §195.452(m) of a situation meeting the following criteria:

(i) The pipeline meets the criteria in paragraph (a) of this section;

(ii) The pipeline carries crude oil from a production facility;

(iii) The pipeline, when in operation, operates at a flow rate less than or equal to 14,000 barrels per day; and

(iv) The operator determines it would abandon or shut-down the pipeline as a result of the economic burden to comply with the assessment requirements in §§ 195.452(d) or 195.452(j).

(2) A notification submitted under this provision must include, at minimum, the following information about the pipeline: Its operating, maintenance and leak history; the estimated cost to comply with the integrity assessment requirements (with a brief description of the basis for the estimate); the estimated amount of production from affected wells per year, whether wells will be shut in or alternate transportation used, and if alternate transportation will be used, the estimated cost to do so.

(3) When an operator notifies PHMSA in accordance with paragraph (c)(1) of this section, PHMSA will stay compliant with §§ 195.452(d) and 195.452(j)(3) until it has completed an analysis of the notification. PHMSA will consult the Department of Energy (DOE), as appropriate, to help analyze the potential energy impact of loss of the pipeline. Based on the analysis, PHMSA may grant the operator a special permit to allow continued operation of the pipeline subject to alternative safety requirements.

(d) *New unusually sensitive areas*. If, after July 3, 2008, an operator identifies a new unusually sensitive area and a segment of pipeline meets the criteria in paragraph (a) of this section, the operator must take the following actions:

(1) Except for paragraph (b)(2) of this section and the requirements of subpart H, comply with all other safety requirements of this part before July 3, 2009. Comply with subpart H before July 3, 2011.

(2) Establish the program required in paragraph (b)(2)(i) within 12 months following the date the area is identified. Continue to carry out such program in compliance with §195.452; and

(3) Complete the baseline assessment required by paragraph (b)(2)(ii) of this section according to the schedule in §195.452(d)(3).

(ed) *Record Retention*. An operator must maintain records demonstrating compliance with each requirement according to the following schedule.

(1) An operator must maintain the segment identification records required in paragraph (b)(1) of this section for the life of the pipe.

(2) An operator must maintain the records necessary to demonstrate compliance with each requirement in paragraphs (b)(2) through (b)(4) of this section according to the record retention requirements of the referenced section or subpart.

(a) *General*. This Section sets forth the requirements for each category of low-stress pipeline in a rural area set forth in paragraph (b) of this Section. This Section does not apply to a rural low-stress pipeline regulated under this Part as a low-stress pipeline that crosses a waterway currently used for commercial navigation; these pipelines are regulated pursuant to §195.1(a)(2).

(b) *Categories*. An operator of a rural low-stress pipeline must meet the applicable requirements and compliance deadlines for the category of pipeline set forth in paragraph (c) of this Section. For purposes of this Section, a rural low-stress pipeline is a Category 1, 2, or 3 pipeline based on the following criteria:

(1) A Category 1 rural low-stress pipeline:

(i) Has a nominal diameter of $8^{8/5}$ inches (219.1 mm) or more;

(ii) Is located in or within one-half mile (.80 km) of an unusually sensitive area (USA) as defined in §195.6; and

(iii) Operates at a maximum pressure established under §195.406 corresponding to:

(A) A stress level equal to or less than 20-percent of the specified minimum yield strength of the line pipe; or

(B) If the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure equal to or less than 125 psi (861 kPa) gauge.

(2) A Category 2 rural pipeline:

(i) Has a nominal diameter of less than $8^{8/5}$ inches (219.1mm);

(ii) Is located in or within one-half mile (.80 km) of an unusually sensitive area (USA) as defined in §195.6; and

(iii) Operates at a maximum pressure established under §195.406 corresponding to:

(A) A stress level equal to or less than 20-percent of the specified minimum yield strength of the line pipe; or

(B) If the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure equal to or less than 125 psi (861 kPa) gage.

(3) A Category 3 rural low-stress pipeline:

(i) Has a nominal diameter of any size and is not located in or within one-half mile (.80 km) of an unusually sensitive area (USA) as defined in §195.6; and

(ii) Operates at a maximum pressure established under §195.406 corresponding to a stress level equal to or less than 20-percent of the specified minimum yield strength of the line pipe; or

(iii) If the stress level is unknown or the pipeline is not constructed with steel pipe, a pressure equal to or less than 125 psi (861 kPa) gage.

(c) *Applicable requirements and deadlines for compliance*. An operator must comply with the following compliance dates depending on the category of pipeline determined by the criteria in paragraph (b):

(1) An operator of a Category 1 pipeline must:

(i) Identify all segments of pipeline meeting the criteria in paragraph (b)(1) of this Section before April 3, 2009.

(ii) Beginning no later than January 3, 2009, comply with the reporting requirements of Subpart B for the identified segments.

(iii) IM requirements--

(A) Establish a written program that complies with §195.452 before July 3, 2009, to assure the integrity of the pipeline segments. Continue to carry out such program in compliance with § 195.452.

(B) An operator may conduct a determination per §195.452(a) in lieu of the one-half mile buffer.

(C) Complete the baseline assessment of all segments in accordance with §195.452(c) before July 3, 2015, and complete at least 50-
percent of the assessments, beginning with the highest risk pipe, before January 3, 2012.

(iv) Comply with all other safety requirements of this Part, except Subpart H, before July 3, 2009. Comply with the requirements of Subpart H before July 3, 2011.

(2) An operator of a Category 2 pipeline must:

(i) Identify all segments of pipeline meeting the criteria in paragraph (b)(2) of this Section before July 1, 2012.

(ii) Beginning no later than January 3, 2009, comply with the reporting

requirements of Subpart B for the identified segments.

(iii) IM--

(A) Establish a written IM program that complies with §195.452 before October 1, 2012 to assure the integrity of the pipeline segments. Continue to carry out such program in compliance with §195.452.

(B) An operator may conduct a determination per § 195.452(a) in lieu of the one-half mile buffer.

(C) Complete the baseline assessment of all segments in accordance with §195.452(c) before October 1, 2016 and complete at least 50-
percent of the assessments, beginning with the highest risk pipe, before April 1, 2014.

(iv) Comply with all other safety requirements of this Part, except Subpart H, before October 1, 2012. Comply with Subpart H of this Part before October 1, 2014.

(3) An operator of a Category 3 pipeline must:

(i) Identify all segments of pipeline meeting the criteria in paragraph (b)(3) of this Section before July 1, 20112.

(ii) Beginning no later than January 3, 2009, comply with the reporting requirements of Subpart B for the identified segments.

(A)(iii) Comply with all safety requirements of this Part, except the requirements in § 195.452, Subpart B, and the requirements in Subpart H, before October 1, 2012. Comply with Subpart H of this Part before October 1, 2014.

(d) *Economic compliance burden*.

(1) An operator may notify PHMSA in accordance with § 195.452(m) of a situation meeting the following criteria:

(i) The pipeline is a Category 1 rural low-stress pipeline;

(ii) The pipeline carries crude oil from a production facility;

(iii) The pipeline, when in operation, operates at a flow rate less than or equal to 14,000 barrels per day; and

(iv) The operator determines it would abandon or shut-down the pipeline as a result of the economic burden to comply with the assessment requirements in §195.452(d) or 195.452(j).

(2) A notification submitted under this provision must include, at minimum, the following information about the pipeline: its operating, maintenance and leak history; the estimated cost to comply with the integrity assessment requirements (with a brief description of the basis for the estimate); the estimated amount of production from affected wells per year, whether wells will be shut in or alternate transportation used, and if alternate transportation will be used, the estimated cost to do so.

(3) When an operator notifies PHMSA in accordance with paragraph (d)(1) of this Section, PHMSA will stay compliance with §§ 195.452(d) and 195.452(j)(3) until it has completed an analysis of the notification. PHMSA will consult the Department of Energy, as appropriate, to help analyze the potential energy impact of loss of the pipeline. Based on the analysis, PHMSA may grant the operator a special permit to allow continued operation of the pipeline subject to alternative safety requirements.

(e) *Changes in unusually sensitive areas*.

(1) If, after June 3, 2008, for Category 1 rural low-stress pipelines or October 1, 2011 for Category 2 rural low-stress pipelines, an operator identifies a new USA that causes a segment of pipeline to meet the criteria in paragraph (b) of this Section as a Category 1 or Category 2 rural low-stress pipeline, the operator must:

(i) Comply with the IM program requirement in paragraph (c)(1)(iii)(A) or (c)(2)(iii)(A) of this Section, as appropriate, within 12 months following the date the area

is identified regardless of the prior categorization of the pipeline; and

(ii) Complete the baseline assessment required by paragraph (c)(1)(iii)(C) or (c)(2)(iii)(C) of this Section, as appropriate, according to the schedule in § 195.452(d)(3).

(2) If a change to the boundaries of a USA causes a Category 1 or Category 2 pipeline segment to no longer be within one-half mile of a USA, an operator must continue to comply with paragraph (c)(1)(iii) or paragraph (c)(2)(iii) of this section, as applicable, with respect to that segment unless the operator determines that a release from the pipeline could not affect the USA.

(f) *Record Retention.* An operator must maintain records demonstrating compliance with each requirement applicable to the category of pipeline according to the following schedule.

(1) An operator must maintain the segment identification records required in paragraph (c)(1)(i), (c)(2)(i) or (c)(3)(i) of this Section for the life of the pipe.

(2) Except for the segment identification records, an operator must maintain the records necessary to demonstrate compliance with each applicable requirement set forth in paragraph (c) of this Section according to the record retention requirements of the referenced Section or Subpart.

[Amdt. 195-[89], 73 FR 31634, June 3, 2008; Amdt. 195-92, 74 FR 62503, Nov. 30, 2009; Amdt. 195-96, 76 FR 25576, May 5, 2011; Amdt. 195-96c, 76 FR 43604, July 21, 2011]

**Subpart B—Annual, Accident, and Safety-Related Condition Reporting**

**§195.48 Scope.**

This subpart prescribes requirements for periodic reporting and for reporting of accidents and safety-related conditions. This Subpart applies to all pipelines subject to this Part.and, beginning January 5, 2009, applies to all rural low-stress hazardous liquid pipelines.
An operator of a Category 3 rural low-stress pipeline not otherwise subject to this part is not required to complete Parts J and K of the hazardous liquid annual report form (PHMSA F 7000-1.1) required by §195.49 or to provide the estimate of total miles that could affect high consequence areas in Part B of that form. meeting the criteria in §195.12 is not required to complete those parts of the hazardous liquid annual report form PHMSA F 7000-1.1 associated with IM or high consequence areas.

[Amdt. 195-[89], 73 FR 31634, June 3, 2008; Amdt. 195-95, 75 FR 72878, Nov 26, 2010; Amdt. 195-96, 76 FR 25576, May 5, 2011]

**§195.49 Annual report.**

Each operator must annually complete and submit DOT Form PHMSA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. An operator must submit the annual report by June 15 each year, except that for the 2010 reporting year the report must be submitted by August 15, 2011. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, carbon dioxide pipelines, and fuel grade ethanol pipelines. For each state a pipeline traverses, an operator must separately complete those sections on the form requiring information to be reported for each state.

Beginning no later than June 15, 2005, each operator must annually complete and submit DOT form RSPA F 7000-1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, and carbon dioxide pipelines. Operators are encouraged, but not required, to file an annual report by June 15, 2004, for calendar year 2003.

[Amdt. 195-80, 69 FR 537, Jan. 6, 2004; Amdt. 195-95, 75 FR 72878, Nov 26, 2010]

**§195.50 Reporting accidents.**

An accident report is required for each failure in a pipeline system subject to this part in which there is a release of the hazardous liquid or carbon dioxide transported resulting in any of the following:

(a) Explosion or fire not intentionally set by the operator.

(b) Release of 5 gallons (19 liters) or more of hazardous liquid or carbon dioxide, except that no report is required for a release of less than 5 barrels (0.8 cubic meters) resulting from a pipeline maintenance activity if the release is:

(1) Not otherwise reportable under this section;

(2) Not one described in §195.52(a)(4);

(3) Confined to company property or pipeline right-of-way; and

(4) Cleaned up promptly;

(c) Death of any person;

(d) Personal injury necessitating hospitalization;

(e) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-15, 44 FR 41197, July 16, 1979; Amdt. 195-22, 46 FR 38357, July 27, 1981, Amdt. 195-39, 53 FR 24942, July 1, 1988; Amdt. 195-45, 56 FR 26922, June 12, 1991; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-63, 63 FR 37500, July 13, 1998; Amdt. 195-75, 67 FR 831, Jan. 8, 2002; Amdt. 195-75a, 67 FR 6436, Feb. 12, 2002]

**§195.52 Telephonic notice of certain accidents.**

(a) Notice requirements At the earliest practicable moment following discovery of a release of the hazardous liquid or carbon dioxide transported resulting in an event described in §195.50, the operator of the system shall give notice, in accordance with paragraph (b) of this section, of any failure that:

(1) Caused a death or a personal injury requiring hospitalization;

(2) Resulted in either a fire or explosion not intentionally set by the operator;

(3) Caused estimated property damage, including cost of cleanup and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000;

(4) Resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality standards, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines; or

(5) In the judgment of the operator was significant even though it did not meet the criteria of any other paragraph of this section.

(b) Reports made under paragraph (a) of this section are made by telephone to 800-424-8802 (in Washington, DC 20590-0001: (202) 372-2428267-2675) and must include the following information:

(b) Information required. Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800-424-8802 (in Washington, DC, 202-267-2675) or electronically at *http://www.nrc.uscg.mil* and must include the following information:

(1) Name and address of the operator.

(1) Name, address and identification number of the operator.

(2) Name and telephone number of the reporter.

(3) The location of the failure.

(4) The time of the failure.

(5) The fatalities and personal injuries, if any.

(6) All other significant facts known by the operator that are relevant to the cause of the failure or extent of the damages.

(6) Initial estimate of amount of product released in accordance with paragraph (c) of this section.

(7) All other significant facts known by the operator that are relevant to the cause of the failure or extent of the damages.

(c) Calculation. A pipeline operator must have a written procedure to calculate and provide a reasonable initial estimate of the amount of released product.

(d) New information. An operator must provide an additional telephonic report to the NRC if significant new information becomes available during the emergency response phase of a reported event at the

earliest practicable moment after such additional information becomes known.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt 195-5, 38 FR 2977, Jan. 31, 1973; Amdt 195-6, 38 FR 7121, Jan. 31, 1973; Amdt. 195-22, 46 FR 38357, July 27, 1981, Amdt. 195-23, 47 FR 32719, July 29, 1982; Amdt. 195-44, 54 FR 40878, Oct. 4, 1989; Amdt. 195-45, 56 FR 26922, June 12, 1991; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-[90], 74 FR 2889, January 16, 2009;Amdt. 195-95, 75 FR 72878, Nov 26, 2010]

**§195.54 Accident reports.**

(a) Each operator that experiences an accident that is required to be reported under §195.50 must,shall as soon as practicable but not later than 30 days after discovery of the accident, accident report on DOT Form 7000-1.prepare and file an accident report on DOT Form 7000-1, or a facsimile.

(b) Whenever an operator receives any changes in the information reported or additions to the original report on DOT Form 7000-1, it shall file a supplemental report within 30 days.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt 195-34, 50 FR 34470, Aug. 26, 1985; Amdt. 195-39, 53 FR 24942, July 1, 1988;Amdt. 195-95, 75 FR 72878, Nov 26, 2010]

**§195.55 Reporting safety-related conditions.**

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §195.56 the existence of any of the following safety-related conditions involving pipelines in service:

(1) General corrosion that has reduced the wall thickness to less than that required for the maximum operating pressure, and localized corrosion pitting to a degree where leakage might result.

(2) Unintended movement or abnormal loading of a pipeline by environmental causes, such as an earthquake, landslide, or flood, that impairs its serviceability.

(3) Any material defect or physical damage that impairs the serviceability of a pipeline.

(4) Any malfunction or operating error that causes the pressure of a pipeline to rise above 110 percent of its maximum operating pressure.

(5) A leak in a pipeline that constitutes an emergency.

(6) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.

(b) A report is not required for any safety-related condition that–

(1) Exists on a pipeline that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway, or that occur offshore or at onshore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water;

(2) Is an accident that is required to be reported under §195.50 or results in such an accident before the deadline for filing the safety-related condition report; or

(3) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for all conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

[Amdt. 195-39, 53 FR 24942, July 1, 1988 as amended by Amdt. 195-39C, 53 FR 36942, Sept. 22, 1988; Amdt. 195-63, 63 FR 37500, July 13, 1998]

**§195.56 Filing safety-related condition reports.**

(a) Each report of a safety-related condition under §195.55(a) must be filed (received by the Administrator) in writing within 5 working days (not including Saturdays, Sundays, or Federal holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. To file a report by facsimile (fax), dial (202) 366-7128.

(b) The report must be headed "Safety-Related Condition Report" and provide the following information:

(1) Name and principal address of operator.

(2) Date of report.

(3) Name, job title, and business telephone number of person submitting the report.

(4) Name, job title, and business telephone number of person who determined that the condition exists.

(5) Date condition was discovered and date condition was first determined to exist.

(6) Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.

(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.

(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt 195-34, 50 FR 34470, Aug. 26, 1985; Amdt. 195-39, 53 FR 24942, July 1, 1988; Amdt. 195-39C, 53 FR 36942, Sept. 22, 1988; Amdt. 195-42, 54 FR 32342, Aug. 7, 1989; Amdt. 195-44, 54 FR 40878, Oct. 4, 1989; Amdt. 195-50, 59 FR 17275, Apr. 12, 1994; Amdt. 195-61, 63 FR 7721, Feb. 17, 1998]

**§195.57 Filing offshore pipeline condition reports.**

(a) Each operator shall, within 60 days after completion of the inspection of all its underwater pipelines subject to §195.413(a), report the following information:

(1) Name and principal address of operator.

(2) Date of report.

(3) Name, job title, and business telephone number of person submitting the report.

(4) Total number of miles (kilometers) of pipeline inspected.

(5) Length and date of installation of each exposed pipeline segment, and location; including, if available, the location according to the Minerals Management Service or state offshore area and block number tract.

(6) Length and date of installation of each pipeline segment, if different from a pipeline segment identified under paragraph (a)(5) of this section, that is a hazard to navigation, and the location; including, if available, the location according to the Minerals Management Service or state offshore area and block number tract.

(b) The report shall be mailed to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001.

[Amdt. 195-47, 56 FR 63764, Dec. 5, 1991 as amended by Amdt. 195-63, 63 FR 37500, July 13, 1998; 70 FR 11135, Mar. 8, 2005; Amdt. 195-[88], 73 FR 16562, Mar. 28, 2008; Amdt. 195-[90], 74 FR 2889, January 16, 2009]

**§195.58 Address for written reports. Report submission requirements.**

(a) *General*. Except as provided in paragraph (b) of this section, an operator must submit each report required by this part electronically to PHMSA at *http://opsweb.phmsa.dot.gov* unless an alternative reporting method is authorized in accordance with paragraph (d) of this section.

(b) *Exceptions*. An operator is not required to submit a safety-related condition report (§195.56) or an offshore pipeline condition report (§195.67) electronically.

(c) *Safety-related conditions.* An operator must submit concurrently to the applicable State agency a safety-related condition report required by §195.55 for an intrastate pipeline or when the State agency acts as an agent of the Secretary with respect to interstate pipelines.

(d) *Alternate Reporting Method*. If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-20, 1200 New Jersey Avenue, SE., Washington DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to *"informationresourcesmanager@dot.gov"* to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

Each written report required by this subpart must be made to the Office of Pipeline Safety, Pipeline Hazardous Materials Safety Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW., Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001. However, accident reports for intrastate pipelines subject to the jurisdiction of a State agency pursuant to a certification under the pipeline safety laws (49 U.S.C.

60101 *et seq.*) may be submitted in duplicate to that State agency if the regulations of that agency require submission of these reports and provide for further transmittal of one copy within 10 days of receipt to the Information Resources Manager. Safety-related condition reports required by §195.55 for intrastate pipelines must be submitted concurrently to the State agency, and if that agency acts as an agent of the Secretary with respect to interstate pipelines, safety-related condition reports for these pipelines must be submitted concurrently to that agency.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt 195-5, 38 FR 2977, Jan. 31, 1973; Amdt. 195-22, 46 FR 38357, July 27, 1981, Amdt. 195-23, 47 FR 32719, July 29, 1982; Amdt 195-34, 50 FR 34470, Aug. 26, 1985; Amdt. 195-39, 53 FR 24942, July 1, 1988; Amdt. 195-50, 59 FR 17275, Apr. 12, 1994; Amdt. 195-55, 61 FR 18512, Apr. 26, 1996; Amdt. 195-81, 69 FR 32886, June 14, 2004; 70 FR 11135, Mar. 8, 2005; Amdt. 195-[90], 74 FR 2889, January 16, 2009;Amdt. 195-95, 75 FR 72878, Nov 26, 2010]

**§195.59 Abandoned underwater facilities report.**

For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

(a) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at *www.npms PHMSA.dot.gov* or contact the NPMS National Repository at 703-317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline Hazardous Materials Safety Administration, Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; fax (202) 366-4566; e-mail, "*InformationResourcesManager@PHMSA.dot.gov*". The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

(b) [Reserved].

[Amdt. 195-69, 65 FR 54440, Sept. 8, 2000 as amended by 70 FR 11135, Mar. 8, 2005; Amdt. 195-86c, 72 FR 4655, February 1, 2007; Amdt. 195-[88], 73 FR 16562, Mar. 28, 2008; Amdt. 195-[90], 74 FR 2889, January 16, 2009]

**§195.60 Operator assistance in investigation.**

If the Department of Transportation investigates an accident, the operator involved shall make available to the representative of the Department all records and information that in any way pertain to the accident, and shall afford all reasonable assistance in the investigation of the accident.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.62 Supplies of accident report DOT Form 7000-1.**

Each operator shall maintain an adequate supply of forms that are a facsimile of DOT Form 7000-1 to enable it to promptly report accidents. The Department will, upon request, furnish specimen copies of the form. Requests should be addressed to the Information Resources Manager, Office of Pipeline Safety, Department of Transportation, Washington, DC 20590Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt 195-5, 38 FR 2977, Jan. 31, 1973; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-23, 47 FR 32719, July 29, 1982; Amdt. 195-[90], 74 FR 2889, January 16, 2009]

**§195.63 OMB control number assigned to information collection.**

The control number assigned by the Office of Management and Budget to the hazardous liquid pipeline information collection pursuant to the Paperwork Reduction Act are 2137-0047, 2137-0601, 2137-0604, 2137-0605, 2137-0618, and 2137-0622.
requirements of this part pursuant to the Paperwork Reduction Act of 1980 is 2137-0047.

[Amdt. 195-34, 50 FR 34470, Aug. 26, 1985 Amdt. 195-95, 75 FR 72878, Nov 26, 2010]

**§195.64 National Registry of Pipeline and LNG Operators.**

(a) OPID Request. Effective January 1, 2012, each operator of a hazardous liquid pipeline or pipeline facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID or a change to an OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline and LNG Operators in accordance with §195.58.

(b) OPID validation. An operator who has already been assigned one or more OPID by January 1, 2011 must validate the information associated with each such OPID through the National Registry of Pipeline and LNG Operators at *http://opsweb.phmsa.dot.gov*, and correct that information as necessary, no later than June 30, 2012.

(c) Changes. Each operator must notify PHMSA electronically through the National

Registry of Pipeline and LNG Operators at *http://opsweb.phmsa.dot.gov*, of certain events.

(1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

(i) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

(ii) Construction of 10 or more miles of a new hazardous liquid pipeline; or

(iii) Construction of a new pipeline facility.

(2) An operator must notify PHMSA of any following event not later than 60 days after the event occurs:

(i) A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.

(ii) A change in the name of the operator;

(iii) A change in the entity (e.g., company, municipality) responsible for operating an existing pipeline, pipeline segment, or pipeline facility;

(iv) The acquisition or divestiture of 50 or more miles of pipeline or pipeline system subject to this part; or

(v) The acquisition or divestiture of an existing pipeline facility subject to this part.

(d) Reporting. An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.

Amdt. 195-95, 75 FR 72878, Nov 26, 2010]

## Subpart C–Design Requirements

### §195.100 Scope.

This subpart prescribes minimum design requirements for new pipeline systems constructed with steel pipe and for relocating, replacing, or otherwise changing existing systems constructed with steel pipe. However, it does not apply to the movement of line pipe covered by §195.424.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

### §195.101 Qualifying metallic components other than pipe.

Notwithstanding any requirement of the subpart which incorporates by reference an edition of a document listed in §195.3, a metallic component other than pipe manufactured in accordance with any other edition of that document is qualified for use if-

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in §195.3:

(1) Pressure testing;

(2) Materials; and,

(3) Pressure and temperature ratings.

[Amdt. 195-28, 48 FR 30637, July 5, 1983]

### §195.102 Design temperature.

(a) Material for components of the system must be chosen for the temperature environment in which the components will be used so that the pipeline will maintain its structural integrity.

(b) Components of carbon dioxide pipelines that are subject to low temperatures during normal operation because of rapid pressure reduction or during the initial fill of the line must be made of materials that are suitable for those low temperatures.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-45, 56 FR 26922, June 12, 1991]

### §195.104 Variations in pressure.

If, within a pipeline system, two or more components are to be connected at a place where one will operate at a higher pressure than another, the system must be designed so that any component operating at the lower pressure will not be overstressed.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

### §195.106 Internal design pressure.

(a) Internal design pressure for the pipe in a pipeline is determined in accordance with the following formula:

$$P = (2\,St/D) \times E \times F$$

***P*** = Internal design pressure in p.s.i. (kPa) gage.

***S*** = Yield strength in pounds per square inch (kPa) determined in accordance with paragraph (b) of this section.

**t** = Nominal wall thickness of the pipe in inches (millimeters) . If this is unknown, it is determined in accordance with paragraph (c) of this section.

***D*** = Nominal outside diameter of the pipe in inches (millimeters).

***E*** =Seam joint factor determined in accordance with paragraph (e) of this section.

***F*** =A design factor of 0.72, except that a design factor of 0.60 is used for pipe, including risers, on a platform located offshore or on a platform in inland navigable waters, and 0.54 is used for pipe that has been subjected to cold expansion to meet the specified minimum yield strength and is subsequently heated, other than by welding or stress relieving as a part of welding, to a temperature higher than 900°F (482°C) for any period of time or over 600°F (316°C) for more than 1 hour.

(b) The yield strength to be used in determining the internal design pressure under paragraph (a) of this section is the specified minimum yield strength. If the specified minimum yield strength is not known, the yield strength to be used in the design formula is one of the following:

(1)(i) The yield strength determined by performing all of the tensile tests of API Specification 5L on randomly selected specimens with the following number of tests:

| Pipe size | Number of tests |
|---|---|
| Less than 6 5/8 in (168 mm) nominal outside diameter. | One test for each 200 lengths. |
| 6 5/8 through 12¾ in (168 through 324 mm) nominal outside diameter. | One test for each 100 lengths. |
| Larger than 12¾ in (324 mm) nominal outside diameter. | One test for each 50 lengths. |

(ii) If the average yield-tensile ratio exceeds 0.85, the yield strength shall be taken as 24,000 p.s.i. (165,474 kPa). If the average yield-tensile ratio is 0.85 or less, the yield strength of the pipe is taken as the lower of the following:

(A) Eighty percent of the average yield strength determined by the tensile tests.

(B) The lowest yield strength determined by the tensile tests.

(2) If the pipe is not tensile tested as provided in paragraph (b) of this section, the yield strength shall be taken as 24,000 p.s.i. (165,474 kPa).

(c) If the nominal wall thickness to be used in determining internal design pressure under paragraph (a) of this section is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end. However, if the pipe is of uniform grade, size, and thickness, only 10 individual lengths or 5 percent of all lengths, whichever is greater, need be measured. The thickness of the lengths that are not measured must be verified by applying a gage set to the minimum thickness found by the measurement. The nominal wall thickness to be used is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness may not be more than 1.14 times the smallest measurement taken on pipe that is less than 20 inches (508 mm) nominal outside diameter, nor more

than 1.11 times the smallest measurement taken on pipe that is 20 inches (508 mm) or more in nominal outside diameter.

(d) The minimum wall thickness of the pipe may not be less than 87.5 percent of the value used for nominal wall thickness in determining the internal design pressure under paragraph (a) of this section. In addition, the anticipated external loads and external pressures that are concurrent with internal pressure must be considered in accordance with §§195.108 and 195.110 and, after determining the internal design pressure, the nominal wall thickness must be increased as necessary to compensate for these concurrent loads and pressures.

(e) The seam joint factor used in paragraph (a) of this section is determined in accordance with the following table:

| Specification | Pipe class | Seam joint factor |
|---|---|---|
| ASTM A53 | Seamless | 1.00 |
| | Electric resistance welded | 1.00 |
| | Furnace lap welded | 0.80 |
| | Furnace butt welded | 0.60 |
| ASTM106 | Seamless | 1.00 |
| ASTM A333/A333M | Seamless | 1.00 |
| | Welded | 1.00 |
| ASTM A381 | Double submerged arc welded | 1.00 |
| ASTM A671 | Electric-fusion welded | 1.00 |
| ASTM A672 | Electric-fusion welded | 1.00 |
| ASTM A691 | Electric-fusion welded | 1.00 |
| API 5L | Seamless | 1.00 |
| | Electric resistance welded | 1.00 |
| | Electric flash welded | 1.00 |
| | Submerged arc welded | 1.00 |
| | Furnace lap welded | 0.80 |
| | Furnace butt welded | 0.60 |

The seam joint factor for pipe which is not covered by this paragraph must be approved by the Administrator.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-2, 35 FR 17183, Nov. 7, 1970; Amdt. 195-11, 41 FR 34035, Aug. 12, 1976; Amdt 195-21, 46 FR 10157, Feb. 2, 1981; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-30, 49 FR 7567, Mar. 1, 1984; Amdt. 195-37, 51 FR 15333, Apr. 23, 1986; Amdt. 195-40, 54 FR 5625, Feb. 6, 1989; Amdt. 195-48, 58 FR 14519, Mar. 18, 1993; Amdt. 195-50, 59 FR 17275, Apr. 12, 1994; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-63, 63 FR 37500, July 13, 1998]

### §195.108 External pressure.

Any external pressure that will be exerted on the pipe must be provided for in designing a pipeline system.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

### §195.110 External loads.

(a) Anticipated external loads (e.g.), earthquakes, vibration, thermal expansion, and contraction must be provided for in designing a pipeline system. In providing for expansion and flexibility, §419 of ASME/ANSI B31.4 must be followed.

(b) The pipe and other components must be supported in such a way that the support does not cause excess localized stresses. In designing attachments to pipe, the added stress to the wall of the pipe must be computed and compensated for.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt 195-9, 41 FR 13590, Mar. 31, 1976; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-48, 58 FR 14519, Mar. 18, 1993]

**§195.111 Fracture propagation.**

A carbon dioxide pipeline system must be designed to mitigate the effects of fracture propagation.

[Amdt. 195-45, 56 FR 26922, June 12, 1991]

**§195.112 New pipe.**

Any new pipe installed in a pipeline system must comply with the following:

(a) The pipe must be made of steel of the carbon, low alloy-high strength, or alloy type that is able to withstand the internal pressures and external loads and pressures anticipated for the pipeline system.

(b) The pipe must be made in accordance with a written pipe specification that sets forth the chemical requirements for the pipe steel and mechanical tests for the pipe to provide pipe suitable for the use intended.

(c) Each length of pipe with a nominal outside diameter of 4½ in (114.3 mm) or more must be marked on the pipe or pipe coating with the specification to which it was made, the specified minimum yield strength or grade, and the pipe size. The marking must be applied in a manner that does not damage the pipe or pipe coating and must remain visible until the pipe is installed.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-63, 63 FR 37500, July 13, 1998]

**§195.114 Used pipe.**

Any used pipe installed in a pipeline system must comply with §195.112 (a) and (b) and the following:

(a) The pipe must be of a known specification and the seam joint factor must be determined in accordance with §195.106(e). If the specified minimum yield strength or the wall thickness is not known, it is determined in accordance with §195.106 (b) or (c) as appropriate.

(b) There may not be any:

(1) Buckles;

(2) Cracks, grooves, gouges, dents, or other surface defects that exceed the maximum depth of such a defect permitted by the specification to which the pipe was manufactured; or

(3) Corroded areas where the remaining wall thickness is less than the minimum thickness required by the tolerances in the specification to which the pipe was manufactured.

However, pipe that does not meet the requirements of paragraph (b)(3) of this section may be used if the operating pressure is reduced to be commensurate with the remaining wall thickness.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-2, 35 FR 17183, Nov. 7, 1970; Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.116 Valves.**

Each valve installed in a pipeline system must comply with the following:

(a) The valve must be of a sound engineering design.

(b) Materials subject to the internal pressure of the pipeline system, including welded and flanged ends, must be

compatible with the pipe or fittings to which the valve is attached.

(c) Each part of the valve that will be in contact with the carbon dioxide or hazardous liquid stream must be made of materials that are compatible with carbon dioxide or each hazardous liquid that it is anticipated will flow through the pipeline system.

(d) Each valve must be both hydrostatically shell tested and hydrostatically seat tested without leakage to at least the requirements set forth in Section 110 of API Standard 6D (incorporated by reference, *see* §195.3).

(e) Each valve other than a check valve must be equipped with a means for clearly indicating the position of the valve (open, closed, etc.).

(f) Each valve must be marked on the body or the nameplate, with at least the following:

(1) Manufacturer's name or trademark.

(2) Class designation or the maximum working pressure to which the valve may be subjected.

(3) Body material designation (the end connection material, if more than one type is used).

(4) Nominal valve size.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-2, 35 FR 17183, Nov. 7, 1970; Amdt 195-9, 41 FR 13590, Mar. 31, 1976; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-45, 56 FR 26922, June 12, 1991; Amdt. 195-86, 71 FR 33402, June 9, 2006; Amdt. 195-94, 75 FR 48593, August 11, 2010]

**§195.118 Fittings.**

(a) Butt-welding type fittings must meet the marking, end preparation, and the bursting strength requirements of ASME/ANSI B16.9 or MSS Standard Practice SP-75.

(b) There may not be any buckles, dents, cracks, gouges, or other defects in the fitting that might reduce the strength of the fitting.

(c) The fitting must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system to which it is attached.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt 195-9, 41 FR 13590, Mar. 31, 1976; Amdt 195-21, 46 FR 10157, Feb. 2, 1981; Amdt. 195-22, 46 FR 38357, July 27, 1981; 47 FR 32721, July 29, 1982, Amdt. 195-48, 58 FR 14519, Mar. 18, 1993 Amdt. 195-94, 75 FR 48593, August 11, 2010]

**§195.120 Passage of internal inspection devices.**

(a) Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each line section of a pipeline where the line pipe, valve, fitting or other line component is replaced, must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

(b) This section does not apply to:

(1) Manifolds;

(2) Station piping such as at pump stations, meter stations, or pressure reducing stations;

(3) Piping associated with tank farms and other storage facilities;

(4) Cross-overs;

(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

(6) Offshore pipelines, other than main lines 10 inches (254 millimeters) or greater in nominal diameter, that transport liquids to onshore facilities; and,

(7) Other piping that the Administrator under §190.9 of this chapter, finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

(c) An operator encountering emergencies, construction time constraints and other unforeseen construction problems need not construct a new or replacement segment of a pipeline to meet paragraph (a) of this section, if the operator determines and documents why an impracticability prohibits compliance with paragraph (a) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under §190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-50, 59 FR 17275, Apr. 12, 1994; Amdt. 195-63, 63 FR 37500, July 13, 1998]

**§195.122 Fabricated branch connections.**

Each pipeline system must be designed so that the addition of any fabricated branch connections will not reduce the strength of the pipeline system.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.124 Closures.**

Each closure to be installed in a pipeline system must comply with the ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Division 1, and must have pressure and temperature ratings at least equal to those of the pipe to which the closure is attached.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt 195-9, 41 FR 13590, Mar. 31, 1976; Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.126 Flange connection.**

Each component of a flange connection must be compatible with each other component and the connection as a unit must be suitable for the service in which it is to be used.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.128 Station piping.**

Any pipe to be installed in a station that is subject to system pressure must meet the applicable requirements of this subpart.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.130 Fabricated assemblies.**

Each fabricated assembly to be installed in a pipeline system must meet the applicable requirements of this subpart.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.132 Design and construction of aboveground breakout tanks.**

(a) Each aboveground breakout tank must be designed and constructed to withstand the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads.

(b) For aboveground breakout tanks first placed in service after October 2, 2000, compliance with paragraph (a) of this section requires one of the following:

(1) Shop-fabricated, vertical, cylindrical, closed top, welded steel tanks with nominal capacities of 90 to 750 barrels (14.3 to 119.2 $m^3$) and with internal vapor space pressures that are approximately atmospheric must be designed and constructed in accordance with API Specification 12F.

(2) Welded, low-pressure (i.e., internal vapor space pressure not greater than 15 psig (103.4 kPa)), carbon steel tanks that have wall shapes that can be generated by a single vertical axis of revolution must be designed and constructed in accordance with API Standard 620.

(3) Vertical, cylindrical, welded steel tanks with internal pressures at the tank top approximating atmospheric pressures (i.e., internal vapor space pressures not greater than 2.5 psig (17.2 kPa), or not greater than the pressure developed by the weight of the tank roof) must be designed and constructed in accordance with API Standard 650.

(4) High pressure steel tanks (i.e., internal gas or vapor space pressures greater than 15 psig (103.4 kPa)) with a nominal capacity of 2000 gallons (7571 liters) or more of liquefied petroleum gas (LPG) must be designed and constructed in accordance with API Standard 2510.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-66, 64 FR 15926, April 2, 1999]

**§195.134 CPM leak detection.**

This section applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid). On such systems, each new computational pipeline monitoring (CPM) leak detection system and each replaced component of an existing CPM system must comply with section 4.2 of API 1130 in its design and with any other design criteria addressed in API 1130 for components of the CPM leak detection system.

[Amdt 195-62 63 FR 36373, July 6, 1998]

## Subpart D–Construction

### §195.200 Scope.

This subpart prescribes minimum requirements for constructing new pipeline systems with steel pipe, and for relocating, replacing, or otherwise changing existing pipeline systems that are constructed with steel pipe. However, this subpart does not apply to the movement of pipe covered by §195.424.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

### §195.202 Compliance with specifications or standards.

Each pipeline system must be constructed in accordance with comprehensive written specifications or standards that are consistent with the requirements of this part.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

### §195.204 Inspection - General.

Inspection must be provided to ensure the installation of pipe or pipeline systems in accordance with the requirements of this subpart. No person may be used to perform inspections unless that person has been trained and is qualified in the phase of construction to be inspected.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-52, 59 FR 33388, June 28, 1994]

### §195.205 Repair, alteration and reconstruction of aboveground breakout tanks that have been in service.

(a) Aboveground breakout tanks that have been repaired, altered, or reconstructed and returned to service must be capable of withstanding the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads.

(b) After October 2, 2000, compliance with paragraph (a) of this section requires the following for the tanks specified:

(1) For tanks designed for approximately atmospheric pressure constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated and tanks built to API Standard 650 or its predecessor Standard 12C, repair, alteration, and reconstruction must be in accordance with API Standard 653.

(2) For tanks built to API Specification 12F or API Standard 620, the repair, alteration, and reconstruction must be in accordance with the design, welding, examination, and material requirements of those respective standards.

(3) For high pressure tanks built to API Standard 2510, repairs, alterations, and reconstruction must be in accordance with API 510.

[Amdt. 195-66, 64 FR 15926, April 2, 1999]

### §195.206 Material inspection.

No pipe or other component may be installed in a pipeline system unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.207 Transportation of pipe.**

(a) *Railroad*. In a pipeline operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless the transportation is performed in accordance with API Recommended Practice 5L1 (incorporated by reference, see §195.3).

(b) *Ship or barge*. In a pipeline operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by ship or barge on both inland and marine waterways, unless the transportation is performed in accordance with API Recommended Practice 5LW (incorporated by reference, see §195.3).

Amdt. 195-94, 75 FR 48593, August 11, 2010]

**§195.208 Welding of supports and braces.**

Supports or braces may not be welded directly to pipe that will be operated at a pressure of more than 100 p.s.i. (689 kPa) gage.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-63, 63 FR 37500, July 13, 1998]

**§195.210 Pipeline location.**

(a) Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly.

(b) No pipeline may be located within 50 feet (15 meters) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate, or assemble, unless it is provided with at least 12 inches (305 millimeters) of cover in addition to that prescribed in §195.248.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-63, 63 FR 37500, July 13, 1998]

**§195.212 Bending of pipe.**

(a) Pipe must not have a wrinkle bend.

(b) Each field bend must comply with the following:

(1) A bend must not impair the serviceability of the pipe.

(2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless–

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12¾ in (324 mm) or less nominal outside diameter or has a diameter to wall thickness ratio less than 70.

(c) Each circumferential weld which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-10, 41 FR 26106, Aug. 16, 1976; Amdt. 195-12, 42 FR 42865, Aug. 25, 1977; Amdt. 195-12C, 42 FR 60148, Nov. 25 1977; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-63, 63 FR 37500, July 13, 1998]

**§195.214 Welding procedures.**

(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 or Section IX of the ASME Boiler and Pressure Vessel Code (ibr, *see* §195.3) . The quality of the test welds used to qualify the welding procedure shall be determined by destructive testing.

(b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-38, 51 FR 20294, June 4, 1986; Amdt. 195-81, 69 FR 32886, June 14, 2004]

**§195.216 Welding: Miter joints.**

A miter joint is not permitted (not including deflections up to 3° that are caused by misalignment).

[Amdt. 195-10, 41 FR 26106, Aug. 16, 1976 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.222 Welders: Qualification of welders.**

(a) Each welder must be qualified in accordance with Section 6 of API 1104 (ibr, *see* §195.3) or Section IX of the ASME Boiler and Pressure Vessel Code, (ibr, *see* §195.3) except that a welder qualified under an earlier edition than listed in §195.3 may weld but may not re-qualify under that earlier edition.

(b) No welder may weld with a welding process unless, within the preceding 6 calendar months, the welder has—

(1) Engaged in welding with that process; and

(2) Had one welded tested and found acceptable under section 9 of API 1104 (ibr, *see* §195.3).

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-8, 40 FR 10181, Mar. 5, 1975; Amdt. 195-8A, 40 FR 27222, June 27, 1975; Amdt. 195-21, 46 FR 10157, Feb. 2, 1981; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-32, 49 FR 36859, Sept. 20, 1984; Amdt. 195-38, 51 FR 20294, June 4, 1986; Amdt. 195-79, 68 FR 53526, Sept. 11, 2003; Amdt. 195-81, 69 FR 32886, June 14, 2004; Amdt. 195-81A, 69 FR 54591, Sept. 9, 2004]

**§195.224 Welding: Weather.**

Welding must be protected from weather conditions that would impair the quality of the completed weld.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.226 Welding: Arc burns.**

(a) Each arc burn must be repaired.

(b) An arc burn may be repaired by completely removing the notch by grinding, if the grinding does not reduce the remaining wall thickness to less than the minimum thickness required by the tolerances in the specification to which the pipe is manufactured. If a notch is not repairable by grinding, a cylinder of the pipe containing the entire notch must be removed.

(c) A ground may not be welded to the pipe or fitting that is being welded.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.228 Welds and welding inspection: Standards of acceptability.**

(a) Each weld and welding must be inspected to ensure compliance with the requirements of this subpart. Visual inspection must be supplemented by nondestructive testing.

(b) The acceptability of a weld is determined according to the standards in Section 9 of API 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API 1104 (ibr, *see* §195.3) applies to the weld, the acceptability of the weld may be determined under that appendix.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt 195-8, 40 FR 10181, Mar. 5, 1975; Amdt 195-8A, 40 FR 27222, June 27, 1975; Amdt 195-21, 46 FR 10157, Feb. 2, 1981; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-81, 69 FR 32886, June 14, 2004]

**§195.230 Welds: Repair or removal of defects.**

(a) Each weld that is unacceptable under §195.228 must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipe lay vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.

(b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

(c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under §195.214. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-11, 41 FR 34035, Aug. 12, 1976; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-29, 48 FR 48669, Oct. 20, 1983]

**§195.234 Welds: Nondestructive testing.**

(a) A weld may be nondestructively tested by an process that will clearly indicate any defects that may affect the integrity of the weld.

(b) Any nondestructive testing of welds must be performed–

(1) In accordance with a written set of procedures for nondestructive testing; and

(2) With personnel that have been trained in the established procedures and in the use of the equipment employed in the testing.

(c) Procedures for the proper interpretation of each weld inspection must be established to ensure the acceptability of the weld under §195.228.

(d) During construction, at least 10 percent of the girth welds made by each welder during each welding day must be nondestructively tested over the entire circumference of the weld.

(e) All girth welds installed each day in the following locations must be nondestructively tested over their entire circumference, except that when nondestructive testing is impracticable for a girth weld, it need not be tested if the number of girth welds for which testing is impracticable does not exceed 10 percent of the girth welds installed that day:

(1) At any onshore location where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water, and any offshore area;

(2) Within railroad or public road rights-of-way;

(3) At overhead road crossings and within tunnels;

(4) Within the limits of any incorporated subdivision of a State government; and,

(5) Within populated areas, including, but not limited to, residential subdivisions, shopping centers, schools, designated commercial areas, industrial facilities, public institutions, and places of public assembly.

(f) When installing used pipe, 100 percent of the old girth welds must be nondestructively tested.

(g) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent of the girth welds must be nondestructively tested.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-1, 35 FR 5332, Mar. 31, 1970; Amdt. 195-11, 41 FR 34035, Aug. 12, 1976; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-26, 48 FR 9013, Mar. 3, 1983; Amdt. 195-35, 50 FR 37191, Sep. 12, 1985; Amdt. 195-52, 59 FR 33388, June 28, 1994]

### §195.246 Installation of pipe in a ditch.

(a) All pipe installed in a ditch must be installed in a manner that minimized the introduction of secondary stresses and the possibility of damage to the pipe.

(b) Except for pipe in the Gulf of Mexico and its inlets in waters less than 15 feet deep, all offshore pipe in water at least 12 feet deep (3.7 meters) but not more than 200 feet deep (61 meters) deep as measured from the mean low water must be installed so that the top of the pipe is below the underwater natural bottom (as determined by recognized and generally accepted practices) unless the pipe is supported by stanchions held in place by anchors or heavy concrete coating or protected by an equivalent means.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-11, 41 FR 34035, Aug. 12, 1976; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-82, 69 FR 48400, Aug. 10, 2004]

### §195.248 Cover over buried pipeline.

(a) Unless specifically exempted in this subpart, all pipe must be buried so that it is below the level of cultivation. Except as provided in paragraph (b) of this section, the pipe must be installed so that the cover between the top of the pipe and the ground level, road bed, river bottom, or underwater natural bottom (as determined by recognized

and generally accepted practices), as applicable, complies with the following table:

| Location | Cover (inches) (millimeters) | |
|---|---|---|
| | For normal excavation | For rock excavation [1] |
| Industrial, commercial, and residential areas | 36 (914) | 30 (762) |
| Crossings of inland bodies of water with a width of at least 100 ft (30 m) from high water mark to high water mark | 48 (1219) | 18 (457) |
| Drainage ditches at public roads and railroads | 36 (914) | 36 (914) |
| Deepwater port safety zone | 48 (1219) | 24 (610) |
| Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water | 36 (914) | 18 (457) |
| Other offshore areas under water less than 12 ft (3.7 meters) deep as measured from mean low water | 36 (914) | 18 (457) |
| Any other area | 30 (762) | 18 (457) |

[1] Rock excavation is any excavation that requires blasting or removal by equivalent means.

(b) Except for the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep, less cover than the minimum required by paragraph (a) of this section and §195.210 may be used if—

(1) It is impracticable to comply with the minimum cover requirements; and

(2) Additional protection is provided that is equivalent to the minimum required cover.

[Amdt. 195-22, 46 FR 38357, July 27, 1981; 47 FR 32721, July 29, 1982, as amended by Amdt. 195-52, 59 FR 33388, June 28, 1994; 59 FR 36256, July 15, 1994; Amdt. 195-63, 63 FR 37500, July 13, 1998; Amdt. 195-82, 69 FR 48400, Aug. 10, 2004]

### §195.250 Clearance between pipe and underground structures.

Any pipe installed underground must have at least 12 inches (305 millimeters) of clearance between the outside of the pipe and the extremity of any other underground structure, except that for drainage tile the minimum clearance may be less than 12 inches (305 millimeters) but not less than 2 inches (51 millimeters). However, where 12 inches (305 millimeters) of clearance is impracticable, the clearance may be reduce if adequate provisions are made for corrosion control.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-63, 63 FR 37500, July 13, 1998]

### §195.252 Backfilling.

When a ditch for a pipeline is backfilled, it must be backfilled in a manner that:

(a) Provides firm support under the pipe; and

(b) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-79, 68 FR 53526, Sept. 11, 2003]

**§195.254 Aboveground components.**

(a) Any component may be installed aboveground in the following situations, if the other applicable requirements of this part are compiled with:

(1) Overhead crossings of highways, railroads, or a body of water.

(2) Spans over ditches and gullies.

(3) Scraper traps or block valves.

(4) Areas under the direct control of the operator.

(5) In any area inaccessible to the public.

(b) Each component covered by this section must be protected from the forces exerted by the anticipated loads.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.256 Crossing of railroads and highways.**

The pipe at each railroad or highway crossing must be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.258 Valves: General.**

(a) Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering.

(b) Each submerged valve located offshore or in inland navigable waters must be marked, or located by conventional survey techniques, to facilitate quick location when operation of the valve is required.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-11, 41 FR 34035, Aug. 12, 1976; Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.260 Valves: Location.**

A valve must be installed at each of the following locations:

(a) On the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency.

(b) On each line entering or leaving a breakout storage tank area in a manner that permits isolation of the tank area from other facilities.

(c) On each mainline at locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas.

(d) On each lateral takeoff from a trunk line in a manner that permits shutting off the lateral without interrupting the flow in the trunk line.

(e) On each side of a water crossing that is more than 100 feet (30 meters) wide from high-water mark to high-water mark unless the Administrator finds in a particular case that valves are not justified.

(f) On each side of a reservoir holding water for human consumption.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt 195-5, 38 FR 2977, Jan. 31, 1973; Amdt. 195-11, 41 FR 34035, Aug. 12, 1976; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-50, 59 FR 17275, Apr. 12, 1994; Amdt. 195-63, 63 FR 37500, July 13, 1998]

**§195.262 Pumping equipment.**

(a) Adequate ventilation must be provided in pump station buildings to prevent the accumulation of hazardous vapors. Warning devices must be installed to warn of the presence of hazardous vapors in the pumping station building.

(b) The following must be provided in each pump station:

(1) Safety devices that prevent overpressuring of pumping equipment, including the auxiliary pumping equipment within the pumping station.

(2) A device for the emergency shutdown of each pumping station.

(3) If power is necessary to actuate the safety devices, an auxiliary power supply.

(c) Each safety device must be tested under conditions approximating actual operations and found to function properly before the pumping station may be used.

(d) Except for offshore pipelines, pumping equipment must be installed on property that is under the control of the operator and at least 15.2 m (50 ft) from the boundary of the pump station.

(e) Adequate fire protection must be installed at each pump station. If the fire protection system installed requires the use of pumps, motive power must be provided for those pumps that is separate from the power that operates the station.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-52, 59 FR 33388, June 28, 1994]

**§195.264 Impoundment, protection against entry, normal/emergency venting or pressure/vacuum relief for aboveground breakout tanks.**

(a) A means must be provided for containing hazardous liquids in the event of spillage or failure of an aboveground breakout tank.

(b) After October 2, 2000, compliance with paragraph (a) of this section requires the following for the aboveground breakout tanks specified:

(1) For tanks built to API Specification 12F, API Standard 620, and others (such as API Standard 650 or its predecessor Standard 12C), the installation of impoundment must be in accordance with the following sections of NFPA 30:

(i) Impoundment around a breakout tank must be installed in accordance with section 4.3.2.3.2; and

(ii) Impoundment by drainage to a remote impounding area must be installed in accordance with section 4.3.2.3.1.

(2) For tanks built to API Standard 2510, the installation of impoundment must be in accordance with section 5 or 11 of API Standard 2510 (incorporated by reference, *see* §195.3).

(c) Aboveground breakout tank areas must be adequately protected against unauthorized entry.

(d) Normal/emergency relief venting must be provided for each atmospheric pressure breakout tank. Pressure/vacuum-relieving devices must be provided for each low-pressure and high-pressure breakout tank.

(e) For normal/emergency relief venting and pressure/vacuum-relieving devices installed on aboveground breakout tanks after October 2, 2000, compliance with paragraph (d) of this section requires the following for the tanks specified:

(1) Normal/emergency relief venting installed on atmospheric pressure tanks built to API Specification 12F (incorporated by reference, see §195.3) must be in accordance with Section 4, and Appendices B and C, of API Specification 12F (incorporated by reference, see §195.3).

(2) Normal/emergency relief venting installed on atmospheric pressure tanks (such as those built to API Standard 650 or its predecessor Standard 12C) must be in accordance with API Standard 2000 (incorporated by reference, see §195.3).

(3) Pressure-relieving and emergency vacuum-relieving devices installed on low pressure tanks built to API Standard (incorporated by reference, see §195.3) must be in accordance with section 9 of API Standard 620 (incorporated by reference, *see* §195.3) and its references to the normal and emergency venting requirements in API Standard 2000 (incorporated by reference, *see* §195.3).

(4) Pressure and vacuum-relieving devices installed on high pressure tanks built to API Standard 2510 (incorporated by reference, see §195.3)must be in accordance with sections 7 or 11 of API Standard 2510 (incorporated by reference, *see* §195.3).

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-66, 64 FR 15926, April 2, 1999; Amdt. 195-86, 71 FR 33402, June 9, 2006] Amdt. 195-94, 75 FR 48593, August 11, 2010]

**§195.266 Construction records.**

A complete record that shows the following must be maintained by the operator involved for the life of each pipeline facility:

(a) The total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld.

(b) The amount, location, and cover of each size of pipe installed.

(c) The location of each crossing of another pipeline.

(d) The location of each buried utility crossing.

(e) The location of each overhead crossing.

(f) The location of each valve and corrosion test station.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-34, 50 FR 34470, Aug. 26, 1985]

## Subpart E–Pressure Testing

### §195.300 Scope.

This subpart prescribes minimum requirements for the pressure testing of steel pipelines. However, this subpart does not apply to the movement of pipe under §195.424.

[Amdt. 195-2, 35 FR 17183, Nov. 7, 1970 as amended by Amdt. 195-17, 45 FR 59161, Sept. 8, 1980; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-33, 50 FR 15895, Apr. 23, 1985; Amdt. 195-51, 59 FR 29379, June 7, 1994]

### §195.302 General requirements.

(a) Except as otherwise provided in this section and in §195.305(b), no operator may operator a pipeline unless it has been pressure tested under this subpart without leakage. In addition, no operator may return to service a segment of pipeline that has been replaced, relocated, or otherwise changed until it has been pressure tested under this subpart without leakage.

(b) Except for pipelines converted under §195.5, the following pipelines may be operated without pressure testing under this subpart:

(1) Any hazardous liquid pipeline whose maximum operating pressure is established under §195.406(a)(5) that is–

(i) An interstate pipeline constructed before January 8, 1971;

(ii) An interstate offshore gathering line constructed before August 1, 1977;

(iii) An intrastate pipeline constructed before October 21, 1985; or

(iv) A low-stress pipeline constructed before August 11, 1994, that transports HVL.

(2) Any carbon dioxide pipeline constructed before July 12, 1991, that-

(i) Has its maximum operating pressure established under §195.406 (a)(5); or

(ii) Is located in a rural area as part of a production field distribution system.

(3) Any low-stress pipeline constructed before August 11, 1994, that does not transport HVL.

(4) Those portions of older hazardous liquid and carbon dioxide pipelines for which an operator has elected the risk-based alternative under §195.303 and which are not required to be tested based on the risk-based criteria.

(c) Except for pipelines that transport HVL onshore, low-stress pipelines, and pipelines covered under §195.303, the following compliance deadlines apply to pipelines under paragraphs (b)(1) and (b)(2)(i) of this section that have not been pressure tested under this subpart:

(1) Before December 7, 1998, for each pipeline each operator shall–

(i) Plan and schedule testing according to this paragraph; or

(ii) Establish the pipelines maximum operating pressure under §195.406(a)(5).

(2) For pipelines scheduled for testing, each operator shall–

(i) Before December 7, 2000, pressure test–

(A) Each pipeline identified by name, symbol, or otherwise that existing records show contains more than 50 percent by mileage (length) of electric resistance welded pipe manufactured before 1970; and

(B) At least 50 percent of the mileage (length) of all other pipelines; and

(ii) Before December 7, 2003, pressure test the remainder of the pipeline mileage (length).

[Amdt. 195-2, 35 FR 17183, Nov. 7, 1970 as amended by Amdt. 195-17, 45 FR 59161, Sept. 8, 1980; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-33, 50 FR 15895, Apr. 23, 1985; Amdt. 195-33C, 50 FR 38659, Sept. 24; 1985; Amdt. 195-51, 59 FR 29379, June 7, 1994; Amdt. 195-51B, 61 FR 43026, Aug. 20, 1996, Amdt. 195-53, 59 FR 35465, July 12, 1994; Amdt. 195-58, 62 FR 54591, Oct. 21, 1997; Amdt. 195-63, 63 FR 37500, July 13, 1998, Amdt. 195-65, 63 FR 59475, Nov. 4, 1998]

**§195.303 Risk-based alternative to pressure testing older hazardous liquid and carbon dioxide pipelines.**

(a) An operator may elect to follow a program for testing a pipeline on risk-based criteria as an alternative to the pressure testing in §195.302(b)(1)(i)-(iii) and §195.302(b)(2)(i) of this subpart. Appendix B provides guidance on how this program will work. An operator electing such a program shall assign a risk classification to each pipeline segment according to the indicators described in paragraph (b) of this section as follows:

(1) Risk Classification A if the location indicator is ranked as low or medium risk, the product and volume indicators are ranked as low risk, and the probability of failure indicator is ranked as low risk;

(2) Risk Classification C if the location indicator is ranked as high risk; or

(3) Risk Classification B.

(b) An operator shall evaluate each pipeline segment in the program according to the following indicators of risk:

(1) The location indicator is—

(i) High risk if an area is non-rural or environmentally sensitive[1]; or

(ii) Medium risk; or

(iii) Low risk if an area is not high or medium risk.

(2) The product indicator is[1]

(i) High risk if the product transported is highly toxic or is both highly volatile and flammable;

(ii) Medium risk if the product transported is flammable with a flashpoint of less than 100 deg. F, but not highly volatile; or

(iii) Low risk if the product transported is not high or medium risk.

(3) The volume indicator is—

(i) High risk if the line is at least 18 inches in nominal diameter;

(ii) Medium risk if the line is at least 10 inches, but less than 18 inches, in nominal diameter; or

(iii) Low risk if the line is not high or medium risk.

(4) The probability of failure indicator is—

(i) High risk if the segment has experienced more than three failures in the last 10 years due to time-dependent defects (e.g., corrosion, gouges, or problems developed during manufacture, construction or operation, etc.); or

(ii) Low risk if the segment has experienced three failures or less in the last 10 years due to time-dependent defects.

(c) The program under paragraph (a) of this section shall provide for pressure testing for a segment constructed of electric resistance-welded (ERW) pipe and lapwelded pipe manufactured prior to 1970 susceptible to longitudinal seam failures as determined through paragraph (d) of this section. The timing of such pressure test may be determined based on risk classifications discussed under paragraph (b) of this section. For other segments, the program may provide for use of a magnetic flux leakage or ultrasonic internal inspection

[1] (See Appendix B, Table C).

survey as an alternative to pressure testing and, in the case of such segments in Risk Classification A, may provide for no additional measures under this subpart.

(d) All pre-1970 ERW pipe and lapwelded pipe is deemed susceptible to longitudinal seam failures unless an engineering analysis shows otherwise. In conducting an engineering analysis an operator must consider the seam-related leak history of the pipe and pipe manufacturing information as available, which may include the pipe steel's mechanical properties, including fracture toughness; the manufacturing process and controls related to seam properties, including whether the ERW process was high-frequency or low-frequency, whether the weld seam was heat treated, whether the seam was inspected, the test pressure and duration during mill hydrotest; the quality control of the steel-making process; and other factors pertinent to seam properties and quality.

(e) Pressure testing done under this section must be conducted in accordance with this subpart. Except for segments in Risk Classification B which are not constructed with pre-1970 ERW pipe, water must be the test medium.

(f) An operator electing to follow a program under paragraph (a) must develop plans that include the method of testing and a schedule for the testing by December 7, 1998. The compliance deadlines for completion of testing are as shown in the table below:

TABLE:—§195.303—TEST DEADLINES

| Pipeline segment | Risk classification | Test deadline |
|---|---|---|
| Pre-1970 Pipe susceptible to longitudinal seam failures [defined in §195.303(c) & (d)] | C or B | 12/7/2000 |
| | A | 12/7/2002 |
| All Other Pipeline | C | 12/7/2002 |
| Segments. | B | 12/7/2004 |
| | A | Additional testing not required. |

(g) An operator must review the risk classifications for those pipeline segments which have not yet been tested under paragraph (a) of this section or otherwise inspected under paragraph (c) of this section at intervals not to exceed 15 months. If the risk classification of an untested or uninspected segment changes, an operator must take appropriate action within two years, or establish the maximum operating pressure under §195.406(a)(5).

(h) An operator must maintain records establishing compliance with this section, including records verifying the risk classifications, the plans and schedule for testing, the conduct of the testing, and the review of the risk classifications.

(i) An operator may discontinue a program under this section only after written notification to the Administrator and approval, if needed, of a schedule for pressure testing.

[Amdt. 195-65, 63 FR 59475, Nov. 4, 1998]

**§195.304 Test pressure.**

The test pressure for each pressure test conducted under this subpart must be maintained throughout the part of the system being tested for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure and, in the case of a pipeline that is not visually inspected for leakage during test, for at least an additional 4 continuous hours at a pressure equal to 110 percent, or more, of the maximum operating pressure.

[Amdt. 195-51, 59 FR 29379, June 7, 1994; Amdt. 195-65, 63 FR 59475, Nov. 4, 1998]

**§195.305 Testing of components.**

(a) Each pressure test under §195.302 must test all pipe and attached fittings, including components, unless otherwise permitted by paragraph (b) of this section.

(b) A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either–

(1) The component was hydrostatically tested at the factory; or

(2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.

[Amdt. 195-2, 35 FR 17183, Nov. 7, 1970 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-51, 59 FR 29379, June 7, 1994; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-65, 63 FR 59475, Nov. 4, 1998]

**§195.306 Test medium.**

(a) Except as provided in paragraph (b), (c), and (d) of this section, water must be used as the test medium.

(b) Except for offshore pipelines, liquid petroleum that does not vaporize rapidly may be used as the test medium if–

(1) The entire pipeline section under test is outside of cities and other populated areas;

(2) Each building within 300 feet (91 meters) of the test section is unoccupied while the test pressure is equal to or greater than a pressure which produces a hoop stress of 50 percent of specified minimum yield strength;

(3) The test section is kept under surveillance by regular patrols during the test; and,

(4) Continuous communication is maintained along entire test section.

(c) Carbon dioxide pipelines may use inert gas or carbon dioxide as the test medium if–

(1) The entire pipeline section under test is outside of cities and other populated areas;

(2) Each building within 300 feet (91 meters) of the test section is unoccupied while the test pressure is equal to or greater than a pressure that produces a hoop stress of 50 percent of specified minimum yield strength;

(3) The maximum hoop stress during the test does not exceed 80 percent of specified minimum yield strength;

(4) Continuous communication is maintained along entire test section; and,

(5) The pipe involved is new pipe having a longitudinal joint factor of 1.00.

(d) Air on inert gas may be used as the test medium in low-stress pipelines.

[Amdt. 195-2, 35 FR 17183, Nov. 7, 1970 as amended by Amdt. 195-3, 36 FR 14618, May 4, 1971; Amdt. 195-11, 41 FR 34035,

Aug. 12, 1976; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-45, 56 FR 26922, June 12, 1991; Amdt. 195-51, 59 FR 29379, June 7, 1994; Amdt. 195-51A, 59 FR 41259, Aug. 11, 1994; Amdt. 195-51B, 59 FR 54328, Oct. 23, Amdt. 195-53, 59 FR 35471, July 12, 1994; Amdt. 195-63, 63 FR 37500, July 13, 1998]

**§195.307 Pressure testing aboveground breakout tanks.**

(a) For aboveground breakout tanks built to API Specification 12F and first placed in service after October 2, 2000, pneumatic testing must be in accordance with section 5.3 of API Specification 12F (incorporated by reference, see §195.3).

(b) For aboveground breakout tanks built to API Standard 620 and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 7.18 of API Standard 620 (incorporated by reference, *see* §195.3).

(c) For aboveground breakout tanks built to API Standard 650 (incorporated by reference, see §195.3) and first placed in service after October 2, 2000,hydrostatic and pneumatic testing must be in accordance with section 5.23 of API Standard 650 (incorporated by reference, see §195.3).

(d) For aboveground atmospheric pressure breakout tanks constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated and tanks built to API Standard 650 or its predecessor Standard 12C that are returned to service after October 2, 2000, the necessity for the hydrostatic testing of repair, alteration, and reconstruction is covered in section 10.3 of API Standard 653.

(e) For aboveground breakout tanks built to API Standard 2510 and first placed in service after October 2, 2000, pressure testing must be in accordance with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 or 2.

[Amdt. 195-66, 64 FR 15926, April 2, 1999 as amended by Amdt. 195-86, 71 FR 33402, June 9, 2006] Amdt. 195-94, 75 FR 48593, August 11, 2010]

**§195.308 Testing of tie-ins.**

Pipe associated with tie-ins must be pressure tested, either with the section to be tied in or separately.

[Amdt. 195-2, 35 FR 17183, Nov. 7, 1970 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-51, 59 FR 29379, June 7, 1994]

**§195.310 Records.**

(a) A record must be made of each pressure test required by this subpart, and the record of the latest test must be retained as long as the facility tested is in use.

(b) The record required by paragraph (a) of this section must include:

(1) The pressure recording charts;

(2) Test instrument calibration data;

(3) The name of the operator, the name of the person responsible for making the test, and the name of the test company used, if any;

(4) The date and time of the test;

(5) The minimum test pressure;

(6) The test medium;

(7) A description of the facility tested and the test apparatus;

(8) An explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts;

(9) Where elevation differences in the section under test exceed 100 feet (30 meters), a profile of the pipeline that shows the elevation and test sites over the entire length of the test section, and

(10) Temperature of the test medium or pipe during the test period.

[Amdt. 195-2, 35 FR 17183, Nov. 7, 1970 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-34, 50 FR 34470, Aug. 26, 1985; Amdt. 195-51, 59 FR 29379, June 7, 1994; Amdt. 195-63, 63 FR 37500, July 13, 1998; Amdt. 195-79, 68 FR 53526, Sept. 11, 2003]

## Subpart F–Operation and Maintenance

### §195.400 Scope.

This subpart prescribes minimum requirements for operating and maintaining pipeline systems constructed with steel pipe.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

### §195.401 General requirements.

(a) No operator may operate or maintain its pipeline systems at a level of safety lower than that required by this subpart and the procedures it is required to establish under §195.402(a) of this subpart.

(b) An operator must make repairs on its pipeline system according to the following requirements:

(1) *Non Integrity management repairs*. Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

(2) *Integrity management repairs*. When an operator discovers a condition on a pipeline covered under §195.452, the operator must correct the condition as prescribed in §195.452(h).

Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

(c) Except as provided by §195.5, no operator may operate any part of any of the following pipelines unless it was designed and constructed as required by this part:

(1) An interstate pipeline, other than a low-stress pipeline, on which construction was begun after March 31, 1970, that transports hazardous liquid.

(2) An interstate offshore gathering line, other than a low-stress, on which construction was begun after July 31, 1977, that transports hazardous liquid.

(3) An intrastate pipeline, other than a low-stress pipeline, on which construction was begun after October 20, 1985, that transports hazardous liquid.

(4) A pipeline, on which construction was begun after July 11, 1991 that transports carbon dioxide.

(5) A low-stress pipeline on which construction was begun after August 10, 1994.

[Amdt. 195-15, 44 FR 41197, July 16, 1979 as amended by Amdt. 195-16, 44 FR 70164, Dec. 6, 1979; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-33, 50 FR 15895, Apr. 23, 1985; Amdt. 195-36, 51 FR 15005, Apr. 22, 1986, Amdt. 195-45, 56 FR 26922, June 12, 1991; Amdt. 195-53, 59 FR 35465, July 12, 1994; Amdt. 195-94, 75 FR 48593, August 11, 2010]

### §195.402 Procedural manual for operations, maintenance, and emergencies.

(a) *General*. Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations

and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline system commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

(b) The Administrator or the State Agency that has submitted a current certification under the pipeline safety laws (49 U.S.C. 60101 *et seq.*) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.237 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

(c) *Maintenance and normal operations*. The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(1) Making construction records, maps, and operating history available as necessary for safe operation and maintenance.

(2) Gathering of data needed for reporting accidents under subpart B of this part in a timely and effective manner.

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart and subpart H of this part.

(4) Determining which pipeline facilities are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned.

(5) Analyzing pipeline accidents to determine their causes.

(6) Minimizing the potential for hazards identified under paragraph (c)(4) of this section and the possibility of recurrence of accidents analyzed under paragraph (c)(5) of this section.

(7) Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within the limits prescribed by paragraph §195.406, consider the hazardous liquid or carbon dioxide in transportation, variations in altitude along the pipeline, and pressure monitoring and control devices.

(8) In the case of pipeline that is not equipped to fail safe, monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by §195.406.

(9) In the case of facilities not equipped to fail safe that are identified under §195.402(c)(4) or that control receipt and delivery of the hazardous liquid or carbon dioxide, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location.

(10) Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place to minimize safety and environmental hazards. For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through commercially navigable waterways the last operator of that facility must file a report upon abandonment of that facility in accordance with §195.59 of this part.

(11) Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph (c)(4) of this section where the potential exists for the presence of flammable liquids or gases.

(12) Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each government organization that may respond to a hazardous liquid or carbon dioxide pipeline emergency and acquaint the officials with the operator's ability in responding to a hazardous liquid or carbon dioxide pipeline emergency and means of communication.

(13) Periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

(14) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.

(15) Implementing the applicable control room management procedures required by §195.446.

(d) *Abnormal operation.* The manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(i) Unintended closure of valves or shutdowns;

(ii) Increase or decrease in pressure or flow rate outside normal operating limits;

(iii) Loss of communications;

(iv) Operation of any safety device;

(v) Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property.

(2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Correcting variations from normal operation of pressure and flow equipment and controls.

(4) Notifying responsible operator personnel when notice of an abnormal operation is received.

(5) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

(e) *Emergencies.* The manual required by paragraph (a) of this section must include procedures for the following to provide safety when an emergency condition occurs;

(1) Receiving, identifying, and classifying notices of events which need immediate response by the operator or notice to fire, police, or other appropriate public officials and communicating this information to appropriate operator personnel for corrective action.

(2) Prompt and effective response to a notice of each type emergency, including fire or explosion occurring near or directly involving a pipeline facility, accidental release of hazardous liquid or carbon dioxide from a pipeline facility, operational failure causing a hazardous condition, and natural disaster affecting pipeline facilities.

(3) Having personnel, equipment, instruments, tools, and material available as needed at the scene of an emergency.

(4) Taking necessary action, such as emergency shutdown or pressure reduction, to minimize the volume of hazardous liquid or carbon dioxide that is released from any section of a pipeline system in the event of a failure.

(5) Control of released hazardous liquid or carbon dioxide at an accident scene to minimize the hazards, including possible

intentional ignition in the cases of flammable highly volatile liquid.

(6) Minimization of public exposure to injury and probability of accidental ignition by assisting with evacuation of residents and assisting with halting traffic on roads and railroads in the affected area, or taking other appropriate action.

(7) Notifying fire, police, and other appropriate public officials of hazardous liquid or carbon dioxide pipeline emergencies and coordinating with them preplanned and actual responses during an emergency, including additional precautions necessary for an emergency involving a pipeline system transporting a highly volatile liquid.

(8) In the case of failure of a pipeline system transporting a highly volatile liquid, use of appropriate instruments to assess the extent and coverage of the vapor cloud and determine the hazardous areas.

(9) Providing for a post accident review of employee activities to determine whether the procedures were effective in each emergency and taking corrective action where deficiencies are found.

(10) Actions required to be taken by a controller during an emergency, in accordance with §195.446.

(f) *Safety-related condition reports.* The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §195.55.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-11, 41 FR 34035, Aug. 12, 1976; Amdt. 195-13, 43 FR 6786, Feb. 16, 1979; Amdt. 195-15, 44 FR 41197, July 16, 1979; Amdt. 195-16, 44 FR 70164, Dec. 6, 1979; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-24, 47 FR 46850, Oct. 21, 1982; Amdt. 195-39, 53 FR 24942, July 1, 1988; Amdt. 195-45, 56 FR 26922, June 12, 1991; Amdt. 195-46, 56 FR 31087, July 9, 1991; Amdt. 195-49, 59 FR 6579, Feb. 11, 1994; Amdt. 195-55, 61 FR 18512, Apr. 26, 1996; Amdt. 195-69, 65 FR 54440, Sept. 8, 2000; Amdt. 195-73, 66 FR 66993, Dec. 27, 2002; Amdt. 192-111, 74 FR 62503, Nov. 30, 2009]

**§195.403 Emergency response training.**

(a) Each operator shall establish and conduct a continuing training program to instruct emergency response personnel to:

(1) Carry out the emergency procedures established under 195.402 that relate to their assignments;

(2) Know the characteristics and hazards of the hazardous liquids or carbon dioxide transported, including, in case of flammable HVL, flammability of mixtures with air, odorless vapors, and water reactions;

(3) Recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and hazardous liquids or carbon dioxide spills, and take appropriate corrective action;

(4) Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage; and

(5) Learn the potential causes, types, sizes, and consequences of fire and the appropriate use of portable fire extinguishers and other on-site fire control equipment, involving, where feasible, a simulated pipeline emergency condition.

(b) At the intervals not exceeding 15 months, but at least once each calendar year, each operator shall:

(1) Review with personnel their performance in meeting the objectives of the emergency response training program set forth in paragraph (a) of this section; and

(2) Make appropriate changes to the emergency response training program as necessary to ensure that it is effective.

(c) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the emergency response procedures established under 195.402 for which they are responsible to ensure compliance.

[Amdt. 195-15, 44 FR 41197, July 16, 1979 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-24, 47 FR 46850, Oct. 21, 1982; Amdt. 195-45, 56 FR 26920, June 12, 1991; Amdt. 192-67, 64 FR 46853, Aug. 27, 1999; Amdt. 195-78, 68 FR 53526, Sept. 11, 2003]

**§195.404 Maps and records.**

(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:

(1) Location and identification of the following pipeline facilities:

(i) Breakout tanks;

(ii) Pump stations;

(iii) Scraper and sphere facilities;

(iv) Pipeline valves;

(v) Facilities to which §195.402(c) (9) applies;

(vi) Rights-of-way; and

(vii) Safety devices to which §195.428 applies.

(2) All crossings of public roads, railroads, rivers, buried utilities, and foreign pipelines.

(3) The maximum operating pressure of each pipeline.

(4) The diameter, grade, type and nominal wall thickness of all pipe.

(b) Each operator shall maintain for at least 3 years daily operating records that indicate–

(1) The discharge pressure at each pump station; and

(2) Any emergency or abnormal operation to which the procedures under §195.402 apply.

(c) Each operator shall maintain the following records for the periods specified:

(1) The date, location, and description of each repair made to pipe shall be maintained for the useful life of the pipe.

(2) The date, location, and description of each repair made to parts of the pipeline system other than pipe shall be maintained for at least 1 year.

(3) A record of each inspection and test required by this subpart shall be maintained for at least 2 years or until the next inspection or test is performed, whichever is longer.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-1, 35 FR 5332, Mar. 31, 1970; Amdt. 195-2, 35 FR 17183, Nov. 7, 1970; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-34, 50 FR 34470, Aug. 26, 1985; Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.405 Protection against ignitions and safe access/egress involving floating roofs.**

(a) After October 2, 2000, protection provided against ignitions arising out of static electricity, lightning, and stray currents during operation and maintenance activities involving aboveground breakout tanks must be in accordance with API Recommended Practice 2003, unless the operator notes in the procedural manual (§195.402(c)) why compliance with all or certain provisions of API Recommended Practice 2003 is not

necessary for the safety of a particular breakout tank.

(b) The hazards associated with access/egress onto floating roofs of in-service aboveground breakout tanks to perform inspection, service, maintenance or repair activities (other than specified general considerations, specified routine tasks or entering tanks removed from service for cleaning) are addressed in API Publication 2026. After October 2, 2000, the operator must review and consider the potentially hazardous conditions, safety practices and procedures in API Publication 2026 for inclusion in the procedure manual (§195.402(c)).

[Amdt. 195-66, 64 FR 15926, April 2, 1999]

**§195.406 Maximum operating pressure.**

(a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:

(1) The internal design pressure of the pipe determined in accordance with §195.106. However, for steel pipe in pipelines being converted under §195.5, if one or more factors of the design formula (§195.106) are unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME B31.8, reduced by the appropriate factors in §§195.106(a) and (e); or

(ii) If the pipe is 12¾ in (324 mm) or less outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The design pressure of any other component of the pipeline.

(3) Eighty percent of the test pressure for any part of the pipeline which has been pressure tested under Subpart E of this part.

(4) Eighty percent of the factory test pressure or of the prototype test pressure for any individually installed component which is excepted from testing under §195.304.

(5) For pipelines under §§195.302(b)(1) and (b)(2)(i), that have not been pressure tested under Subpart E of this part, 80 percent of the test pressure or highest operating pressure to which the pipeline was subjected for 4 or more continuous hours that can be demonstrated by recording charts or logs made at the time the test or operations were conducted.

(b) No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

[Amdt. 195-2, 35 FR 17183, Nov. 7, 1970 as amended by Amdt. 195-17, 45 FR 59161, Sep. 8, 1980; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-33, 50 FR 15895, Apr. 23, 1985; Amdt. 195-33C, 50 FR 38659, Sep. 24, 1985; Amdt. 195-51, 59 FR 29379, June 7, 1994; Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-63, 63 FR 37500, July 13, 1998; Amdt. 195-65, 63 FR 59475, Nov. 4, 1998]

**§195.408 Communications.**

(a) Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.

(b) The communication system required by paragraph (a) of this section must, as a minimum, include means for:

(1) Monitoring operational data as required by §195.402(c)(9);

(2) Receiving notices from operator personnel, the public, and public authorities of abnormal or emergency conditions and sending this information to appropriate personnel or government agencies for corrective action;

(3) Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies; and,

(4) Providing communication with fire, police, and other public officials during emergency conditions, including a natural disaster.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-15, 44 FR 41197, July 16, 1979; Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.410 Line markers.**

(a) Except as provided in paragraph (b) of this section, each operator shall place and maintain line markers over each buried pipeline in accordance with the following:

(1) Markers must be located at each public road crossing, at each railroad crossing, and in sufficient number along the remainder of each buried line so that its location is accurately known.

(2) The marker must state at least the following on a background of sharply contrasting color:

(i) The word "Warning," "Caution," or "Danger" followed by the words "Petroleum (or the name of the hazardous liquid transported) Pipeline," or "Carbon Dioxide Pipeline," all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with an approximate stroke of ¼-inch (6.4 millimeters) .

(ii) The name of the operator and a telephone number (including area code) where the operator can be reached at all times.

(b) Line markers are not required for buried pipelines located–

(1) Offshore or at crossings of or under waterways and other bodies of water; or

(2) In heavily developed urban areas such as downtown business centers where–

(i) The placement of markers is impractical and would not serve the purpose for which markers are intended; and

(ii) The local government maintains current substructure records.

(c) Each operator shall provide line marking at locations where the line is aboveground in areas that are accessible to the public.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-27, 48 FR 25206, June 6, 1983, Amdt. 195-45, 56 FR 26922, June 12, 1991; Amdt. 195-54, 60 FR 14646, Mar. 20, 1995; Amdt. 195-63, 63 FR 37500, July 13, 1998]

**§195.412 Inspection of rights-of-way and crossings under navigable waters.**

(a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate mean of traversing the right-of-way.

(b) Except for offshore pipelines, each operator shall, at intervals not exceeding 5 years, inspect each crossing under a

navigable waterway to determine the condition of the crossing.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-24, 47 FR 48650, Oct. 21, 1982; Amdt. 195-52, 59 FR 33388, June 28, 1994]

**§195.413 Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.**

(a) Except for gathering lines of 4½ inches (114mm) nominal outside diameter or smaller, each operator shall prepare and follow a procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water that are at risk of being an exposed underwater pipeline or a hazard to navigation. The procedures must be in effect August 10, 2005.

(b) Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk.

(c) If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall—

(1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802, of the location and, if available, the geographic coordinates of that pipeline.

(2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR Part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and

(3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year of discovery, bury the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) for normal excavation or 18 inches (457 millimeters) for rock excavation.

(i) An operator may employ engineered alternatives to burial that meet or exceed the level of protection provided by burial.

(ii) If an operator cannot obtain required state or Federal permits in time to comply with this section, it must notify OPS; specify whether the required permit is State or Federal; and, justify the delay.

[Amdt. 195-47, 56 FR 63764, Dec. 5, 1991, as amended by Amdt. 195-52, 59 FR 33388, June 28, 1994; Amdt. 195-63, 63 FR 37500, July 13, 1998; Amdt. 195-82, 69 FR 48400, Aug. 10, 2004]

**§195.420 Valve maintenance.**

(a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

(b) Each operator shall, at intervals not exceeding 7½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

(c) Each operator shall provide protection for each valve from unauthorized operation and from vandalism.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-24, 47 FR 46850, Oct. 21, 1982]

**§195.422 Pipeline repairs.**

(a) Each operator shall, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons or property.

(b) No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.424 Pipe movement.**

(a) No operator may move any line pipe, unless the pressure in the line section involved is reduced to not more than 50 percent of the maximum operating pressure.

(b) No operator may move any pipeline containing highly volatile liquids where materials in the line section involved are joined by welding unless–

(1) Movement when the pipeline does not contain highly volatile liquids is impractical;

(2) The procedures of the operator under §195.402 contain precautions to protect the public against the hazard in moving pipelines containing highly volatile liquids, including the use of warnings, where necessary, to evacuate the area close to the pipeline; and

(3) The pressure in that line section is reduced to the lower of the following:

(i) Fifty percent or less of the maximum operating pressure; or

(ii) The lowest practical level that will maintain the highly volatile liquid in a liquid state with continuous flow, but not less than 50 p.s.i. (345 kPa) gage above the vapor pressure of the commodity.

(c) No operator may move any pipeline containing highly volatile liquids where materials in the line section involved are not joined by welding unless–

(1) The operator complies with paragraphs (b)(1) and (2) of this section; and

(2) That line section is isolated to prevent the flow of highly volatile liquid.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt 195-7, 39 FR 19780, June 4, 1974; Amdt. 195-15, 44 FR 41197, July 16, 1979; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-63, 63 FR 37500, July 13, 1998]

**§195.426 Scraper and sphere facilities.**

No operator may use a launcher or receiver that is not equipped with a relief device capable of safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. The operator must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent insertion or removal of scrapers or spheres if pressure has not been relieved in the barrel.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-15, 44 FR 41197, July 16, 1979; Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.428 Overpressure safety devices and overfill protection systems.**

(a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at

least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

(b) In the case of relief valves on pressure breakout tanks containing highly volatile liquids, each operator shall test each valve at intervals not exceeding 5 years.

(c) Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Other aboveground breakout tanks with 600 gallons (2271 liters) or more of storage capacity that are constructed or significantly altered after October 2, 2000, must have an overfill protection system installed according to API Recommended Practice 2350. However, operators need not comply with any part of API Recommended Practice 2350 for a particular breakout tank if the operator notes in the manual required by §195.402 why compliance with that part is not necessary for safety of the tank.

(d) After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-4, 37 FR 18733, Sep. 15, 1972; Amdt. 195-15, 44 FR 41197, July 16, 1979; Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-24, 47 FR 46850, Oct. 21, 1982; Amdt. 195-66, 64 FR 15926, April 2, 1999]

**§195.430 Firefighting equipment.**

Each operator shall maintain adequate firefighting equipment at each pump station and breakout tank area. The equipment must be–

(a) In proper operating condition at all times;

(b) Plainly marked so that its identity as firefighting equipment is clear; and,

(c) Located so that it is easily accessible during a fire.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.432 Inspection of in-service breakout tanks.**

(a) Except for breakout tanks inspected under paragraphs (b) and (c) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank.

(b) Each operator mustshall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to API Standard 653 (incorporated by reference, see §195.3).section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under §195.402(c)(3).

(c) Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API

Standard 2510 according to section 6 of API 510.

(d) The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-24, 47 FR 46850, Oct. 21, 1982; Amdt. 195-66, 64 FR 15926, April 2, 1999] Amdt. 195-94, 75 FR 48593, August 11, 2010]

**§195.434 Signs.**

Each operator must maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-79, 68 FR 53526, Sept. 11, 2003]

**§195.436 Security of facilities.**

Each operator shall provide protection for each pumping station and breakout tank area and other exposed facility (such as scraper traps) from vandalism and unauthorized entry.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.438 Smoking or open flames.**

Each operator shall prohibit smoking and open flames in each pump station area and each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or of the presence of flammable vapors.

[Part 195 - Org., Oct. 4, 1969 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981]

**§195.440 Public awareness.**

(a) Each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference, *see* §195.3).

(b) The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities.

(c) The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

(d) The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

(1) Use of a one-call notification system prior to excavation and other damage prevention activities;

(2) Possible hazards associated with unintended releases from a hazardous liquid or carbon dioxide pipeline facility;

(3) Physical indications that such a release may have occurred;

(4) Steps that should be taken for public safety in the event of a hazardous liquid or carbon dioxide pipeline release; and

(5) Procedures to report such an event.

(e) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

(f) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports hazardous liquid or carbon dioxide.

(g) The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

(h) Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. Upon request, operators must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility operator, the appropriate State agency.

(i) The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies.

[Amdt. 195-15, 44 FR 41197, July 16, 1979 as amended by Amdt. 195-22, 46 FR 38357, July 27, 1981; Amdt. 195-45, 56 FR 26922, June 12, 1991; Amdt. 195-84, 70 FR 28833, May 19, 2005; Amdt. 195-86, 71 FR 33402, June 9, 2006]

**§195.442 Damage prevention program.**

(a) Except as provided in paragraph (d) of this section, each operator of a buried pipeline shall carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purpose of this section, the term "excavation activities" include excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earth moving operations.

(b) An operator may comply with any of the requirements of paragraph (c) of this section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a "qualified one-call system" if it meets the requirements of section (b)(1) or (b)(2) of this section.

(1) The state has adopted a one-call damage prevention program under §198.37 of this chapter; or

(2) The one-call system:

(i) Is operated in accordance with §198.39 of this chapter;

(ii) Provides a pipeline operator an opportunity similar to a voluntary participant

to have a part in management responsibilities; and

(iii) Assesses a participating pipeline operator a fee that is proportionate to the costs of the one-call system's coverage of the operator's pipeline.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.

(2) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program:

(i) The program's existence and purpose; and

(ii) How to learn the location of underground pipelines before excavation activities are begun.

(3) Provide a means of receiving and recording notification of planned excavation activities.

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

(5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

(ii) In the case of blasting, any inspection must include leakage surveys.

(d) A damage prevention program under this section is not required for the following pipelines:

(1) Pipelines located offshore.

(2) Pipelines to which access is physically controlled by the operator.

[Amdt. 195-54, 53 FR 14646, Mar. 20, 1995; Amdt. 195-60, 62 FR 61695, Nov. 19, 1997]

### §195.444 CPM leak detection.

Each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline transporting liquid in a single phase (without gas in the liquid) must comply with API 1130 in operating, maintaining, testing, record keeping, and dispatcher training of the system.

[Amdt. 195-62, 63 FR 36373, July 6, 1998]

***Editorial Note:*** *This section is all new and therefore not underlined.*

### §195.446 Control room management.

(a) *General*. This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. The procedures required by this section must be integrated, as appropriate, with the operator's written procedures required by §195.402. An operator must develop the procedures no later than August 1, 2011, and

implement the procedures no later than February 1, 20132. and must implement the procedures according to the following schedule. The procedures required by paragraphs (b), (c)(5), (d)(2) and (d)(3), (f) and (g) of this section must be implemented no later than October 1, 2011. The procedures required by paragraphs (c)(1) through (4), (d)(1), (d)(4), and (e) must be implemented no later than August 1, 2012. The training procedures required by paragraph (h) must be implemented no later than August 1, 2012, except that any training required by another paragraph of this section must be implemented no later than the deadline for that paragraph.

(b) *Roles and responsibilities*. Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

(1) A controller's authority and responsibility to make decisions and take actions during normal operations;

(2) A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

(3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others; and

(4) A method of recording controller shift-changes and any hand-over of responsibility between controllers.

(c) *Provide adequate information*. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

(1) Implement API RP 1165 (incorporated by reference, see §195.3) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of API RP 1165 are not practical for the SCADA system used;

(2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

(3) Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months;

(4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and

(5) Implement section 5 of API RP 1168 (incorporated by reference, see §195.3) to establish procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

(d) *Fatigue mitigation*. Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:

(1) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;

(2) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

(3) Train controllers and supervisors to recognize the effects of fatigue; and

(4) Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

(e) *Alarm management*. Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

(1) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;

(2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;

(3) Verify the correct safety-related alarm set-point values and alarm descriptions when associated field instruments are calibrated or changed and at least once each calendar year, but at intervals not to exceed 15 months;

(4) Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan;

(5) Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not exceeding 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and

(6) Address deficiencies identified through the implementation of paragraphs (e)(1) through (e)(5) of this section.

(f) *Change management*. Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:

(1) Implement section 7 of API RP 1168 (incorporated by reference, see §195.3) for control room management change and require coordination between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration; and

(2) Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations.

(g) *Operating experience*. Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:

(1) Review accidents that must be reported pursuant to §195.50 and 195.52 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to:

(i) Controller fatigue;

(ii) Field equipment;

(iii) The operation of any relief device;

(iv) Procedures;

(v) SCADA system configuration; and

(vi) SCADA system performance.

(2) Include lessons learned from the operator's experience in the training program required by this section.

(h) *Training*. Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the

training program must include the following elements:

(1) Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

(2) Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions;

(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures;

(4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions; and

(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application.

(i) *Compliance validation*. Upon request, operators must submit their procedures to PHMSA or, in the case of an intrastate pipeline facility regulated by a State, to the appropriate State agency.

(j) *Compliance and deviations*. An operator must maintain for review during inspection:

(1) Records that demonstrate compliance with the requirements of this section; and

(2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of the pipeline facility.

[Amdt. 195-93, 74 FR 62503, Nov. 30, 2009 as amended by Amdt. 195-93c, 75 FR 5536, Feb. 3, 2010; Amdt. 195-97, 76 FR 35130 June 16, 2011]

## HIGH CONSEQUENCE AREAS

### §195.450 Definitions.

The following definitions apply to this section and §195.452:

*Emergency flow restricting device or EFRD* means a check valve or remote control valve as follows:

(1) *Check valve* means a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction.

(2) *Remote control valve* or *RCV* means any valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.

*High consequence area* means:

(1) A *commercially navigable waterway*, which means a waterway where a substantial likelihood of commercial navigation exists;

(2) A *high population area*, which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;

(3) An *other populated area*, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area;

(4) An *unusually sensitive area*, as defined in §195.6.

[Amdt. 195-70, 65 FR 75378, Dec. 1, 2000]

**PIPELINE INTEGRITY MANAGEMENT**

**§195.452 Pipeline integrity management in high consequence areas.**

(a) *Which pipelines are covered by this section?* This section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. (Appendix C of this part provides guidance on determining if a pipeline could affect a high consequence area.) Covered pipelines are categorized as follows:

(1) Category 1 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to this part.

(2) Category 2 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to this part.

(3) Category 3 includes pipelines constructed or converted after May 29, 2001.

(b) *What program and practices must operators use to manage pipeline integrity? Each operator of a pipeline covered by this section must:*

(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column:

| Pipeline | Date |
|---|---|
| Category 1 | March 31, 2002. |
| Category 2 | February 18, 2003. |
| Category 3 | 1 year after the date the pipeline begins operation. |

(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:

| Pipeline | Date |
|---|---|
| Category 1 | December 31, 2001 |
| Category 2 | November 18, 2002. |
| Category 3 | Date the pipeline begins operation. |

(3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.

(4) Include in the program a framework that—

(i) Addresses each element of the integrity management program under paragraph (f) of this section, including continual integrity assessment and evaluation under paragraph (j) of this section; and

(ii) Initially indicates how decisions will be made to implement each element.

(5) Implement and follow the program.

(6) Follow recognized industry practices in carrying out this section, unless—

(i) This section specifies otherwise; or

(ii) The operator demonstrates that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection.

(c) *What must be in the baseline assessment plan?* (1) An operator must include each of the following elements in its written baseline assessment plan:

(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity

and of detecting corrosion and deformation anomalies.

(A) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;

(B) Pressure test conducted in accordance with subpart E of this part;

(C) External corrosion direct assessment in accordance with §195.588; or

(D) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

(ii) A schedule for completing the integrity assessment;

(iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule.

(2) An operator must document, prior to implementing any changes to the plan, any modification to the plan, and reasons for the modification.

(d) *When must operators complete baseline assessments?* Operators must complete baseline assessments as follows:

(1) *Time periods.* Complete assessments before the following deadlines:

| If the pipeline is: | Then complete baseline assessments not later than the following date according to a schedule that prioritizes assessments | And assess at least 50 percent of the line pipe on an expedited basis, beginning with the highest risk pipe, not later than: |
|---|---|---|
| Category 1 | March 31, 2008. | September 30, 2004. |
| Category 2 | February 17, 2009. | August 16, 2005. |
| Category 3 | Date the pipeline begins operation. | Not applicable. |

(2) *Prior assessment.* To satisfy the requirements of paragraph (c)(1)(i) of this section for pipelines in the first column of the following table, operators may use integrity assessments conducted after the date in the second column, if the integrity assessment method complies with this section. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to paragraph (j)(3) of this section. The table follows:

| Pipeline | Date |
|---|---|
| Category 1 | January 1, 1996. |
| Category 2 | February 15, 1997. |

(3) *Newly-identified areas.* (i) When information is available from the information analysis (see paragraph (g) of this section), or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in §195.450 of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

(ii) An operator must incorporate a new unusually sensitive area into its baseline assessment plan within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

(e) *What are the risk factors for establishing an assessment schedule (for*

*both the baseline and continual integrity assessments)?* (1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to:

(i) Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;

(ii) Pipe size, material, manufacturing information, coating type and condition, and seam type;

(iii) Leak history, repair history and cathodic protection history;

(iv) Product transported;

(v) Operating stress level;

(vi) Existing or projected activities in the area;

(vii) Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic);

(viii) geo-technical hazards; and (ix) Physical support of the segment such as by a cable suspension bridge.

(2) Appendix C of this part provides further guidance on risk factors.

(f) *What are the elements of an integrity management program?* An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:

(1) A process for identifying which pipeline segments could affect a high consequence area;

(2) A baseline assessment plan meeting the requirements of paragraph (c) of this section;

(3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);

(4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);

(5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);

(6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph (i) of this section);

(7) Methods to measure the program's effectiveness (see paragraph (k) of this section);

(8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).

(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:

(1) Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment;

(2) Data gathered through the integrity assessment required under this section;

(3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and

(4) Information about how a failure would affect the high consequence area, such as location of the water intake.

(h) *What actions must an operator take to address integrity issues?*

(1) *General requirements.* An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with §195.422 when making a repair.

(i) *Temporary pressure reduction.* An operator must notify PHMSA, in accordance with paragraph (m) of this section, if the operator cannot meet the schedule for evaluation and remediation required under paragraph (h)(3) of this section and cannot provide safety through a temporary reduction in operating pressure.

(ii) Long-term pressure reduction. When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with paragraph (m) of this section and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline.

(2) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

(3) *Schedule for evaluation and remediation*. An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety or environmental protection.

(4) *Special requirements for scheduling remediation.*

(i) *Immediate repair conditions*. An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formula in section 451.6.2.2 (b) of ANSI/ASME B31.4 (incorporated by reference, see §195.3).451.7 of ASME/ANSI B31.4 (incorporated by reference, *see* §195.3), if applicable. If the formula is not applicable to the type of anomaly or would produce a higher operating pressure, an operator must use an alternative acceptable method to calculate a reduced operating pressure. An operator must treat the following conditions as immediate repair conditions:

(A) Metal loss greater than 80% of nominal wall regardless of dimensions.

(B) A calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the

anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are incorporated by reference and are available at the addresses listed in §195.3.

(C) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.

(D) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter.

(E) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(ii) *60-day conditions.* Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following conditions within 60 days of discovery of condition.

(A) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3% of the pipeline diameter (greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(B) A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.

(iii) *180-day conditions.* Except for conditions listed in paragraph (h)(4)(i) or (ii) of this section, an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition:

(A) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

(B) A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).

(C) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(D) A calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991)) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are incorporated by reference and are available at the addresses listed in §195.3.

(E) An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.

(F) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.

(G) A potential crack indication that when excavated is determined to be a crack.

(H) Corrosion of or along a longitudinal seam weld.

(I) A gouge or groove greater than 12.5% of nominal wall.

(iv) *Other conditions.* In addition to the conditions listed in paragraphs (h)(4)(i)

through (iii) of this section, an operator must evaluate any condition identified by an integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation. Appendix C of this part contains guidance concerning other conditions that an operator should evaluate.

(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?*

(1) *General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls.

(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:

(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;

(ii) Elevation profile;

(iii) Characteristics of the product transported;

(iv) Amount of product that could be released;

(v) Possibility of a spillage in a farm field following the drain tile into a waterway;

(vi) Ditches along side a roadway the pipeline crosses;

(vii) Physical support of the pipeline segment such as by a cable suspension bridge;

(viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

(3) *Leak detection.* An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider, the following factors–length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

(4) *Emergency Flow Restricting Devices (EFRD).* If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors–the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline

segment and the high consequence area, and benefits expected by reducing the spill size.

(j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?*

(1) *General*. After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area.

(2) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

(3) *Assessment intervals*. An operator must establish five-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

(4) *Variance from the 5-year intervals in limited situations.*

(i) *Engineering basis.* An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in paragraph (j)(5) of this section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a longer interval, and propose an alternative interval. An operator must send the notice to the address specified in paragraph (m) of this section.

(ii) *Unavailable technology.* An operator may require a longer assessment period for a segment of line pipe (for example, because sophisticated internal inspection technology is not available). An operator must justify the reasons why it cannot comply with the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must notify OPS 180 days before the end of the five-year (or less) interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed. An operator must send a notice to the address specified in paragraph (m) of this section.

(5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(i) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;

(ii) Pressure test conducted in accordance with subpart E of this part;

(iii) External corrosion direct assessment in accordance with §195.588; or

(iv) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section.

(k) *What methods to measure program effectiveness must be used?* An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See Appendix C of this part for guidance on methods that can be used to evaluate a program's effectiveness.

(l) *What records must be kept?*

(1) An operator must maintain for review during an inspection:

(i) A written integrity management program in accordance with paragraph (b) of this section.

(ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.

(2) See Appendix C of this part for examples of records an operator would be required to keep.

(m) *How does an operator notify PHMSA?* An operator must provide any notification required by this section by:

(1) Entering the information directly on the Integrity Management Database Web site at *http://primis.PHMSA.dot.gov/imdb/*;

(2) Sending the notification to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue, SE., Washington, DC 20590; or

(3) Sending the notification to the Information Resources Manager by facsimile to (202) 366-7128.

[Amdt. 195-70, 65 FR 75378, Dec. 1, 2000 as amended by Amdt. 195-74, 67 FR 1650, Jan. 14, 2002; Amdt. 195-76, 67 FR 2136, Jan. 16, 2002, Amdt. 195-76a, 67 FR 46911, July 17, 2002; 70 FR 11135, Mar. 8, 2005; Amdt. 195-85, 70 FR 61571, Oct. 25, 2005; Amdt. 195-87, 72 FR 39012, July 17, 2007; Amdt. 195-[88], 73 FR 16562, Mar. 28, 2008; Amdt. 195-[89], 73 FR 31634, June 3, 2008] Amdt. 195-94, 75 FR 48593, August 11, 2010]

## Subpart G —Qualification of Pipeline Personnel

### §195.501 Scope.

(a) This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.

(b) For the purpose of this subpart, a covered task is an activity, identified by the operator, that:

(1) Is performed on a pipeline facility;

(2) Is an operations or maintenance task;

(3) Is performed as a requirement of this part; and

(4) Affects the operation or integrity of the pipeline.

### §195.503 Definitions.

*Abnormal operating condition* means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(a) indicate a condition exceeding design limits; or

(b) result in a hazard(s) to persons, property, or the environment.

*Evaluation* means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

(a) Written examination;

(b) Oral examination;

(c) Work performance history review;

(d) Observation during:

(1) performance on the job,

(2) on the job training, or

(3) simulations;

(e) Other forms of assessment.

*Qualified* means that an individual has been evaluated and can:

(a) perform assigned covered tasks and

(b) recognize and react to abnormal operating conditions.

[Amdt. 195-67, 64 FR 46853, Aug. 27, 1999 as amended by Amdt. 195-72, 66 FR 43523, Aug. 20, 2001]

### §195.505 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(a) Identify covered tasks;

(b) Ensure through evaluation that individuals performing covered tasks are qualified;

(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;

(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an accident as defined in Part 195;

(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

(f) Communicate changes that affect covered tasks to individuals performing those covered tasks;

(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed.;

(h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601

if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.

[Amdt. 195-67, 64 FR 46853, Aug. 27, 1999 as amended by Amdt. 195-84, 70 FR 10322, Mar. 3, 2005]

**§195.507 Recordkeeping.**

Each operator shall maintain records that demonstrate compliance with this subpart.

(a) Qualification records shall include:

(1) Identification of qualified individual(s);

(2) Identification of the covered tasks the individual is qualified to perform;

(3) Date(s) of current qualification; and

(4) Qualification method(s).

(b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.

[Amdt. 195-67, 64 FR 46853, Aug. 27, 1999]

**§195.509 General.**

(a) Operators must have a written qualification program by April 27, 2001. The program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.

(b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

(c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999.

(d) After October 28, 2002, work performance history may not be used as a sole evaluation method.

(e) After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

[Amdt. 195-67, 64 FR 46853, Aug. 27, 1999 as amended by Amdt. 195-72, 66 FR 43523, Aug. 20, 2001; Amdt. 195-84, 70 FR 10322, Mar. 3, 2005]

## Subpart H—Corrosion Control

### §195.551 What do the regulations in this subpart cover?

This subpart prescribes minimum requirements for protecting steel pipelines against corrosion.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

### §195.553 What special definitions apply to this subpart?

As used in this subpart—

Active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety or the environment.

*Buried* means covered or in contact with soil.

*Direct assessment* means an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

*Electrical survey* means a series of closely spaced pipe-to-soil readings over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

*External corrosion direct assessment (ECDA)* means a four-step process that combines pre-assessment, indirect inspection, direct examination, and post-assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

*Pipeline environment* includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

*You* means operator.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002; Amdt. 195-85, 70 FR 61571, Oct. 25, 2005]

### §195.555 What are the qualifications for supervisors?

You must require and verify that supervisors maintain a thorough knowledge of that portion of the corrosion control procedures established under §195.402(c)(3) for which they are responsible for insuring compliance.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

### §195.557 Which pipelines must have coating for external corrosion control?

Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is—

(a) Constructed, relocated, replaced, or otherwise changed after the applicable date in §195.401(c), not including the movement of pipe covered by §195.424; or

(b) Converted under §195.5 and—

(1) Has an external coating that substantially meets §195.559 before the pipeline is placed in service; or

(2) Is a segment that is relocated, replaced, or substantially altered.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.559 What coating material may I use for external corrosion control?**

Coating material for external corrosion control under §195.557 must—

(a) Be designed to mitigate corrosion of the buried or submerged pipeline;

(b) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;

(c) Be sufficiently ductile to resist cracking;

(d) Have enough strength to resist damage due to handling and soil stress;

(e) Support any supplemental cathodic protection; and

(f) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.561 When must I inspect pipe coating used for external corrosion control?**

(a) You must inspect all external pipe coating required by §195.557 just prior to lowering the pipe into the ditch or submerging the pipe.

(b) You must repair any coating damage discovered.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.563 Which pipelines must have cathodic protection?**

(a) Each buried or submerged pipeline that is constructed, relocated, replaced, or otherwise changed after the applicable date in §195.401(c) must have cathodic protection. The cathodic protection must be in operation not later than 1 year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable.

(b) Each buried or submerged pipeline converted under §195.5 must have cathodic protection if the pipeline—

(1) Has cathodic protection that substantially meets §195.571 before the pipeline is placed in service; or

(2) Is a segment that is relocated, replaced, or substantially altered.

(c) All other buried or submerged pipelines that have an effective external coating must have cathodic protection.[1] Except as provided by paragraph (d) of this section, this requirement does not apply to breakout tanks and does not apply to buried piping in breakout tank areas and pumping stations until December 29, 2003.

(d) Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where regulations in effect before January 28, 2002 required cathodic protection as a result of electrical inspections. See previous editions of this part in 49 CFR, parts 186 to 199.

(e) Unprotected pipe must have cathodic protection if required by §195.573(b).

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

[1] A pipeline does not have an effective external coating material if the current required to cathodically protect the pipeline is substantially the same as if the pipeline were bare.

**§195.565 How do I install cathodic protection on breakout tanks?**

After October 2, 2000, when you install cathodic protection under §195.563(a) to protect the bottom of an aboveground breakout tank of more than 500 barrels ($79.5m^3$) capacity built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the system in accordance with API Recommended Practice 651. However, installation of the system need not comply with API Recommended Practice 651 on any tank for which you note in the corrosion control procedures established under §195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of the tank.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.567 Which pipelines must have test leads and what must I do to install and maintain the leads?**

(a) *General.* Except for offshore pipelines, each buried or submerged pipeline or segment of pipeline under cathodic protection required by this subpart must have electrical test leads for external corrosion control. However, this requirement does not apply until December 27, 2004 to pipelines or pipeline segments on which test leads were not required by regulations in effect before January 28, 2002.

(b) *Installation.* You must install test leads as follows:

(1) Locate the leads at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection.

(2) Provide enough looping or slack so backfilling will not unduly stress or break the lead and the lead will otherwise remain mechanically secure and electrically conductive.

(3) Prevent lead attachments from causing stress concentrations on pipe.

(4) For leads installed in conduits, suitably insulate the lead from the conduit.

(5) At the connection to the pipeline, coat each bared test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

(c) *Maintenance.* You must maintain the test lead wires in a condition that enables you to obtain electrical measurements to determine whether cathodic protection complies with §195.571.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.569 Do I have to examine exposed portions of buried pipelines?**

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the exposed portion for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under §195.585, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.571 What criteria must I use to determine the adequacy of cathodic protection?**

Cathodic protection required by this subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard SRP 0169 (incorporated by reference, *see* §195.3).

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002 as amended by Amdt. 195-86, 71 FR 33402, June 9, 2006; Amdt. 195-94, 75 FR 48593, August 11, 2010]

**§195.573 What must I do to monitor external corrosion control?**

(a) *Protected pipelines.* You must do the following to determine whether cathodic protection required by this subpart complies with §195.571:

(1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months.

(2) Identify not more than 2 years after cathodic protection is installed, the circumstances in which a close-interval survey or comparablewhichever comes later, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard RP 0169 (incorporated by reference, *see* §195.3).

(b) *Unprotected pipe.* You must reevaluate your unprotected buried or submerged pipe and cathodically protect the pipe in areas in which active corrosion is found, as follows:

(1) Determine the areas of active corrosion by electrical survey, or where an electrical survey is impractical, by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) For the period in the first column, the second column prescribes the frequency of evaluation.

| Period | Evaluation frequency |
|---|---|
| Before December 29, 2003 | At least once every 5 calendar years, but with intervals not exceeding 63 months. |
| Beginning December 29, 2003 | At least once every 3 calendar years, but with intervals not exceeding 39 months. |

(c) *Rectifiers and other devices.* You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

| Device | Check frequency |
|---|---|
| Rectifier<br><br>Reverse current switch<br>Diode<br>Interference bond whose failure would jeopardize structural protection. | At least six times each calendar year, but with intervals not exceeding 2½ months. |
| Other interference bond | At least once each calendar year, but with intervals not exceeding 15 months. |

(d) *Breakout tanks.* You must inspect each cathodic protection system used to control corrosion on the bottom of an

aboveground breakout tank to ensure that operation and maintenance of the system are in accordance with API Recommended Practice 651. However, this inspection is not required if you note in the corrosion control procedures established under §195.402(c)(3) why compliance with all or certain operation and maintenance provisions of API Recommended Practice 651 is not necessary for the safety of the tank.

(e) *Corrective action.* You must correct any identified deficiency in corrosion control as required by §195.401(b). However, if the deficiency involves a pipeline in an integrity management program under §195.452, you must correct the deficiency as required by §195.452(h).

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002 as amended by Amdt. 195-73A, 67 FR 70118, Nov. 20, 2002: Amdt. 195-86, 71 FR 33402, June 9, 2006; Amdt. 195-94, 75 FR 48593, August 11, 2010]

**§195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?**

(a) You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit.

(b) You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.

(d) If you install an insulating device in an area where a combustible atmosphere is reasonable to foresee, you must take precautions to prevent arcing.

(e) If a pipeline is in close proximity to electrical transmission tower footings, ground cables, or counterpoise, or in other areas where it is reasonable to foresee fault currents or an unusual risk of lightning, you must protect the pipeline against damage from fault currents or lightning and take protective measures at insulating devices.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.577 What must I do to alleviate interference currents?**

(a) For pipelines exposed to stray currents, you must have a program to identify, test for, and minimize the detrimental effects of such currents.

(b) You must design and install each impressed current or galvanic anode system to minimize any adverse effects on existing adjacent metallic structures.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.579 What must I do to mitigate internal corrosion?**

(a) *General.* If you transport any hazardous liquid or carbon dioxide that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion.

(b) *Inhibitors.* If you use corrosion inhibitors to mitigate internal corrosion, you must—

(1) Use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect;

(2) Use coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion; and

(3) Examine the coupons or other monitoring equipment at least twice each calendar year, but with intervals not exceeding 7½ months.

(c) *Removing pipe.* Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under §195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

(d) *Breakout tanks.* After October 2, 2000, when you install a tank bottom lining in an aboveground breakout tank built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the lining in accordance with API Recommended Practice 652. However, installation of the lining need not comply with API Recommended Practice 652 on any tank for which you note in the corrosion control procedures established under §195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 652 is not necessary for the safety of the tank.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.581 Which pipelines must I protect against atmospheric corrosion and what coating material may I use?**

(a) You must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, you need not protect against atmospheric corrosion any pipeline for which you demonstrate by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.583 What must I do to monitor atmospheric corrosion control?**

(a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

| If the pipeline is located: | Then the frequency of inspection is: |
|---|---|
| Onshore | At least once every 3 calendar years, but with intervals not exceeding 39 months. |
| Offshore | At least once each calendar year, but with intervals not exceeding 15 months. |

(b) During inspections you must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by §195.581.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.585 What must I do to correct corroded pipe?**

(a) *General corrosion.* If you find pipe so generally corroded that the remaining wall thickness is less than that required for the maximum operating pressure of the pipeline, you must replace the pipe. However, you need not replace the pipe if you—

(1) Reduce the maximum operating pressure commensurate with the strength of the pipe needed for serviceability based on actual remaining wall thickness; or (2) Repair the pipe by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(b) *Localized corrosion pitting.* If you find pipe that has localized corrosion pitting to a degree that leakage might result, you must replace or repair the pipe, unless you reduce the maximum operating pressure commensurate with the strength of the pipe based on actual remaining wall thickness in the pits.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.587 What methods are available to determine the strength of corroded pipe?**

Under §195.585, you may use the procedure in ASME B31G, "Manual for Determining the Remaining Strength of Corroded Pipelines," or the procedure developed by AGA/Battelle, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk)," to determine the strength of corroded pipe based on actual remaining wall thickness. These procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations set out in the respective procedures.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

**§195.588 What standards apply to direct assessment?**

(a) If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion, you must follow the requirements of this section for performing external corrosion direct assessment. This section does not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

(b) The requirements for performing external corrosion direct assessment are as follows:

(1) *General.* You must follow the requirements of NACE Standard SRP0502-2002 (incorporated by reference, *see* §195.3). Also, you must develop and implement an External Corrosion Direct Assessment (ECDA) plan that includes procedures addressing pre-assessment,

indirect examination, direct examination, and post-assessment.

(2) *Pre-assessment*. In addition to the requirements in Section 3 of NACE SP0502 (incorporated by reference, see §195.3), the ECDA plan procedures for pre-assessment must include--Standard RSP0502-2002, the ECDA plan procedures for pre-assessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;

(ii) The basis on which you select at least two different, but complementary, indirect assessment tools to assess each ECDA region; and

(iii) If you utilize an indirect inspection method not described in Appendix A of NACE Standard RP0502-2002, SP0502 (incorporated by reference, see §195.3), you must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(3) *Indirect examination*. In addition to the requirements in Section 4 of NACE SP0502 (incorporated by reference, see §195.3)Standard RP0502-2002, the procedures for indirect examination of the ECDA regions must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination, including at least the following:

(A) The known sensitivities of assessment tools;

(B) The procedures for using each tool; and

(C) The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) For each indication identified during the indirect examination, criteria for—

(A) Defining the urgency of excavation and direct examination of the indication; and

(B) Defining the excavation urgency as immediate, scheduled, or monitored; and

(iv) Criteria for scheduling excavations of indications in each urgency level.

(4) *Direct examination*. In addition to the requirements in Section 5 of NACE SP0502 (incorporated by reference, see §195.3)Standard RP0502-2002, the procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE Standard SRP0502-2002SP0502 (incorporated by reference, see §195.3) provides guidance for criteria); or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE SP0502 (incorporated by reference, see §195.3)Standard RP0502-2002 provides guidance for criteria);

(iii) Criteria and notification procedures for any changes in the ECDA plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis you will reclassify and re-prioritize any of the provisions specified in Section 5.9 of NACE SP0502 (incorporated by reference, see §195.3)Standard RP0502-2002.

(5) *Post assessment and continuing evaluation.* In addition to the requirements in Section 6 of NACE SP 0502 (incorporated by reference, see §195.3)Standard UP 0502-2002, the procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in pipeline segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the pipeline segment at an interval less than that specified in Sections 6.2 and 6.3 of NACE SP0502 (see appendix D of NACE SP0502) (incorporated by reference, see §195.3)Standard RP0502-2002 (see Appendix D of NACE Standard RP0502-2002).

[Amdt. 195-85, 70 FR 61571, Oct. 25, 2005] Amdt. 195-94, 75 FR 48593, August 11, 2010]

**§195.589 What corrosion control information do I have to maintain?**

(a) You must maintain current records or maps to show the location of—

(1) Cathodically protected pipelines;

(2) Cathodic protection facilities, including galvanic anodes, installed after January 28, 2002; and

(3) Neighboring structures bonded to cathodic protection systems.

(b) Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(c) You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to §§ 195.569, 195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.

[Amdt. 195-73, 66 FR 66993, Dec. 27, 2002]

## APPENDIX A-DELINEATION BETWEEN FEDERAL AND STATE JURSIDICTION– STATEMENT OF AGENCY POLICY AND INTERPRETATION

In 1979, Congress enacted comprehensive safety legislation governing the transportation of hazardous liquids by pipeline, the Hazardous Liquids Pipeline Safety Act of 1979, 49 U.S.C. 2001 *et seq.* (HLPSA). The HLPSA expanded the existing statutory authority for safety regulation, which was limited to transportation by common carriers in interstate and foreign commerce, to transportation through facilities used in or affecting interstate or foreign commerce. It also added civil penalty, compliance order, and injunctive enforcement authorities to the existing criminal sanctions. Modeled largely on the Natural Gas Pipeline Safety Act of 1968, 49 U.S.C. 1671 *et seq.* (NGPSA), the HLPSA provides for a national hazardous liquid pipeline safety program with nationally uniform minimal standards and with enforcement administered through a Federal-State partnership. The HLPSA leaves to exclusive Federal regulation and enforcement the "interstate pipeline facilities," those used for the pipeline transportation of hazardous liquids in interstate or foreign commerce. For the remainder of the pipeline facilities, denominated "intrastate pipeline facilities," the HLPSA provides that the same Federal regulation and enforcement will apply unless a State certifies that it will assume those responsibilities. A certified State must adopt the same minimal standards but may adopt additional more stringent standards so long as they are compatible. Therefore, in States which participate in the hazardous liquid pipeline safety program through certification, it is necessary to distinguish the interstate from the intrastate pipeline facilities.

In deciding that an administratively practical approach was necessary in distinguishing between interstate and intrastate liquid pipeline facilities and in determining how best to accomplish this, DOT has logically examined the approach used in the NGPSA. The NGPSA defines the interstate gas pipeline facilities subject to exclusive Federal jurisdiction as those subject to the economic regulatory jurisdiction of the Federal Energy Regulatory Commission (FERC). Experience has proven this approach practical. Unlike the NGPSA however, the HLPSA has no specific reference to FERC jurisdiction, but instead defines interstate liquid pipeline facilities by the more commonly used means of specifying the end points of the transportation involved. For example, the economic regulatory jurisdiction of FERC over the transportation of both gas and liquids by pipeline is defined in much the same way. In implementing the HLPSA DOT has sought a practicable means of distinguishing between interstate and intrastate pipeline facilities that provide the requisite degree of certainty to Federal and State enforcement personnel and to the regulated entities. DOT intends that this statement of agency policy and interpretation provide that certainty.

In 1981, DOT decided that the inventory of liquid pipeline facilities identified as subject to the jurisdiction of FERC approximates the HLPSA category of "interstate pipeline facilities." Administrative use of the FERC inventory has the added benefit of avoiding the creation of a separate Federal scheme for determination of jurisdiction over the same regulated entities. DOT recognizes that the FERC inventory is only an approximation and may not be totally satisfactory without

some modification. The difficulties stem from some significant differences in the economic regulation of liquid and of natural gas pipelines. There is an affirmative assertion of jurisdiction by FERC over natural gas pipelines through the issuance of certificates of public convenience and necessity prior to commencing operations. With liquid pipelines, there is only a rebuttable presumption of jurisdiction created by the filing by pipeline operators of tariffs (or concurrences) for movement of liquids through existing facilities. Although FERC does police the filings for such matters as compliance with the general duties of common carriers, the question of jurisdiction is normally only aired upon complaint. While any person, including State or Federal agencies can avail themselves of the FERC forum by use of the complaint process, that process has only been rarely used to review jurisdictional matters (probably because of the infrequency of real disputes on the issue). Where the issue has arisen, the reviewing body has noted the need to examine various criteria primarily of an economic nature. DOT believes that, in most cases, the formal FERC forum can better receive and evaluate the type of information that is needed to make decisions of this nature than can DOT.

In delineating which liquid pipeline facilities are interstate pipeline facilities within the meaning of the HLPSA, DOT will generally rely on the FERC filings; that is, if there is a tariff or concurrence filed with FERC governing the transportation of hazardous liquids over a pipeline facility or if there has been an exemption from the obligation to file tariffs obtained from FERC, then DOT will, as a general rule, consider the facility to be an interstate pipeline facility within the meaning of the HLPSA. The types of situations in which DOT will ignore the existence or non-existence of a filing with FERC will be limited to those cases in which it appears obvious that a complaint filed with FERC would be successful or in which blind reliance on a FERC filing would result in a situation clearly not intended by the HLPSA such as a pipeline facility not being subject to either State or Federal safety regulation. DOT anticipates that the situations in which there is any question about the validity of the FERC filings as a ready reference will be few and that the actual variations from reliance on those filings will be rare. The following examples indicate the types of facilities which DOT believes are interstate pipeline facilities subject to the HLPSA despite the lack of a filing with FERC and the types of facilities over which DOT will generally defer to the jurisdiction of a certifying state despite the existence of a filing with FERC.

*Example 1*. Pipeline company P operates a pipeline from "Point A" located in State X to "Point B" (also in X). The physical facilities never cross a state line and do not connect with any other pipeline which does cross a state line. Pipeline company P also operates another pipeline between "Point C" in State X and "Point D" in an adjoining State Y. Pipeline company P files a tariff with FERC for transportation from "Point A" to "Point B" as well as for transportation from "Point C" to "Point D." DOT will ignore filing for the line from "Point A" to "Point B" and consider the line to be intrastate.

*Example 2*. Same as in example 1 except that P does not file any tariffs with FERC. DOT will assume jurisdiction of the line between "Point C" and "Point D."

*Example 3*. Same as in example 1 except that P files its tariff for the line

between "Point C" and "Point D" not only with FERC but also with State X. DOT will rely on the FERC filing as indication of interstate commerce.

*Example 4.* Same as in example 1 except that the pipeline from "Point A" to "Point B" (in State X) connects with a pipeline operated by another company that transports liquid between "Point B" (in State X) and "Point D" (in State Y). DOT will rely on the FERC filing as indication of interstate commerce.

*Example 5.* Same as in example 1 except that the line between "Point C" and "Point D" has a lateral line connected to it. The lateral is located entirely within State X. DOT will rely on the existence or non-existence of a FERC filing covering transportation over that lateral as determinative of interstate commerce.

*Example 6.* Same as in example 1 except that the certified agency in State X has brought an enforcement action (under the pipeline safety laws) against P because of its operation of the line between "Point A" and "Point B." P has successfully defended against the action on jurisdictional grounds. DOT will assume jurisdiction if necessary to avoid the anomaly of a pipeline subject to neither State nor Federal safety enforcement. DOT's assertion of jurisdiction in such a case would be based on the gap in the State's enforcement authority rather than a DOT decision that the pipeline is an interstate pipeline facility.

*Example 7.* Pipeline Company P operates a pipeline that originates on the Outer Continental Shelf. P does not file any tariff for that line with FERC. DOT will consider the pipeline to be an interstate pipeline facility.

*Example 8.* Pipeline Company P is constructing a pipeline from "Point C" (in State X) to "Point D" (in State Y). DOT will consider the pipeline to be an interstate pipeline facility.

*Example 9.* Pipeline company P is constructing a pipeline from "Point C" to "Point E" (both in State X) but intends to file tariffs with FERC in the transportation of hazardous liquid in interstate commerce. Assuming there is some connection to an interstate pipeline facility, DOT will consider this line to be an interstate pipeline facility.

*Example 10.* Pipeline Company P has operated a pipeline subject to FERC economic regulation. Solely because of some statutory economic deregulation, that pipeline is no longer regulated by FERC. DOT will continue to consider that pipeline to be an interstate pipeline facility.

As seen from the examples, the types of situations in which DOT will not defer to the FERC regulatory scheme are generally clear-cut cases. For the remainder of the situations where variation from the FERC scheme would require DOT to replicate the forum already provided by FERC and to consider economic factors better left to that agency, DOT will decline to vary its reliance on the FERC filings unless, of course, not doing so would result in situations clearly not intended by the HLPSA.

[Amdt. 195-33, 50 FR 15895, Apr. 23, 1985]

## APPENDIX B—RISK-BASED ALTERNATIVE TO PRESSURE TESTING OLDER HAZARDOUS LIQUID AND CARBON DIOXIDE PIPELINES

### Risk-Based Alternative

This Appendix provides guidance on how a risk-based alternative to pressure testing older hazardous liquid and carbon dioxide pipelines rule allowed by §195.303 will work. This risk-based alternative establishes test priorities for older pipelines, not previously pressure tested, based on the inherent risk of a given pipeline segment. The first step is to determine the classification based on the type of pipe or on the pipeline segment's proximity to populated or environmentally sensitive area. Secondly, the classifications must be adjusted based on the pipeline failure history, product transported, and the release volume potential.

Tables 2-6 give definitions of risk classification A, B, and C facilities. For the purposes of this rule, pipeline segments containing high risk electric resistance-welded pipe (ERW pipe) and lapwelded pipe manufactured prior to 1970 and considered a risk classification C or B facility shall be treated as the top priority for testing because of the higher risk associated with the susceptibility of this pipe to longitudinal seam failures.

In all cases, operators shall annually, at intervals not to exceed 15 months, review their facilities to reassess the classification and shall take appropriate action within two years or operate the pipeline system at a lower pressure. Pipeline failures, changes in the characteristics of the pipeline route, or changes in service should all trigger a reassessment of the originally classification.

Table 1 explains different levels of test requirements depending on the inherent risk of a given pipeline segment. The overall risk classification is determined based on the type of pipe involved, the facility's location, the product transported, the relative volume of flow and pipeline failure history as determined from Tables 2-6.

TABLE 1.—TEST REQUIREMENTS—MAINLINE SEGMENTS OUTSIDE OF TERMINALS, STATIONS, AND TANK FARMS

| Pipeline segment | Risk classification | Test deadline[1] | Test medium |
|---|---|---|---|
| Pre-1970 Pipeline Segments susceptible to longitudinal seam failures[2] | C or B | 12/7/2000 | Water only. |
| | A | 12/7/2002[3] | Water only. |
| All Other Pipeline Segments. | C | 12/7/2002[3] | Water only. |
| | B | 12/7/2004[4] | Water/Liq.[5] |
| | A | Additional pressure testing not required. | |

[1] If operational experience indicates a history of past failures for a particular pipeline system, failure causes (time-dependent defects due to corrosion, construction, manufacture, or transmission problems, etc.) shall be reviewed in determining risk classification (See Table 6) and the timing of the pressure test should be accelerated.
[2] All pre-1970 ERW pipeline segments may not require testing. In determining which ERW pipeline segments should be included in this category, an operator must consider the seam-related leak history of the pipe and pipe manufacturing information as available, which may include the pipe steel's mechanical properties, including fracture toughness; the manufacturing process and controls related to seam properties, including whether the ERW process was high-frequency or low-frequency, whether the weld seam was heat treated, whether the seam was inspected, the test pressure and duration during mill hydrotest; the quality control of the steel-making process; and other factors pertinent to seam properties and quality.
[3] For those pipeline operators with extensive mileage of pre-1970 ERW pipe, any waiver requests for timing relief should be supported by an assessment of hazards in accordance with location, product, volume, and probability of failure considerations consistent with Tables 3, 4, 5, and 6.
[4] A magnetic flux leakage or ultrasonic internal inspection survey may be utilized as an alternative to pressure testing where leak history and operating experience do not indicate leaks caused by longitudinal cracks or seam failures.
[5] Pressure tests utilizing a hydrocarbon liquid may be conducted, but only with a liquid which does not vaporize rapidly.

Using LOCATION, PRODUCT, VOLUME, and FAILURE HISTORY "Indicators" from Tables 3, 4, 5, and 6 respectively, the overall risk classification of a given pipeline or pipeline segment can be established from Table 2. The LOCATION Indicator is the primary factor which determines overall risk, with the PRODUCT, VOLUME, and PROBABILITY OF FAILURE Indicators used to adjust to a higher or lower overall risk classification per the following table.

TABLE 2.—RISK CLASSIFICATION

| Risk classification | Hazard location indicator | Product/volume indicator | Probability of failure indicator |
|---|---|---|---|
| A | L or M | L/L | L |
| B | Not A or C Risk Classification | | |
| C | H | Any | Any |

H=High, M=Moderate, and L=Low.

**Note: For Location, Product, Volume, and Probability of Failure Indicators, see Tables 3, 4, 5, and 6.**

TABLE 3.—LOCATION INDICATORS—PIPELINE SEGMENTS

| Indicator | Population[1] | Environment[2] |
|---|---|---|
| H | Non-rural areas | |
| M | | |
| L | Rural areas | |

[1]The effects of potential vapor migration should be considered for pipeline segments transporting highly volatile or toxic products.
[2]We expect operators to use their best judgment in applying this factor.

Tables 4, 5 and 6 are used to establish the PRODUCT, VOLUME, and PROBABILITY OF FAILURE Indicators respectively, in Table 2. The PRODUCT Indicator is selected from Table 4 as H, M, or L based on the acute and chronic hazards associated with the product transported. The VOLUME Indicator is selected from Table 5 as H, M, or L based on the nominal diameter of the pipeline. The Probability of Failure Indicator is selected from Table 6.

TABLE 4.—PRODUCT INDICATORS

| Indicator | Considerations | Product examples |
|---|---|---|
| H | (Highly volatile and flammable). | (Propane, butane, Natural Gas Liquid (NGL), ammonia). |
| | Highly toxic | (Benzene, high Hydrogen Sulfide content crude oils). |
| M | Flammable—flashpoint <100F. | (Gasoline, JP4, low flashpoint crude oils). |
| L | Non-flammable—flashpoint 100+F | (Diesel, fuel oil, kerosene, JP5, most crude oils). |
| | Highly volatile and non-flammable/non-toxic. | Carbon Dioxide. |

Considerations: The degree of acute and chronic toxicity to humans, wildlife, and aquatic life; reactivity; and, volatility, flammability, and water solubility determine the Product Indicator. Comprehensive Environmental Response, Compensation and Liability Act Reportable Quantity values can be used as an indication of chronic toxicity. National Fire Protection Association health factors can be used for rating acute hazards.

TABLE 5.—VOLUME INDICATORS

| Indicator | Line size |
|---|---|
| H | ≥ 18" |
| M | 10"-16" nominal diameters. |
| L | ≤ 8" nominal diameter. |

H=High, M=Moderate, and L=Low.

Table 6 is used to establish the PROBABILITY OF FAILURE Indicator used in Table 2. The "Probability of Failure" Indicator is selected from Table 6 as H or L.

TABLE 6.—PROBABILITY OF FAILURE INDICATORS (IN EACH HAZ. LOCATION)

| Indicator | Failure history (time-dependent defects)[2] |
|---|---|
| H[1] | > Three spills in last 10 years. |
| L | ≤ Three spills in last 10 years. |

H=High and L=Low.

[1]Pipeline segments with greater than three product spills in the last 10 years should be reviewed for failure causes as described in subnote[2]. The pipeline operator should make an appropriate investigation and reach a decision based on sound engineering judgment, and be able to demonstrate the basis of the decision.
[2]Time-Dependent Defects are defects that result in spills due to corrosion, gouges, or problems developed during manufacture, construction or operation, etc.

[Amdt. 195-65, 63 FR 59475, November 4, 1998 as amended by Amdt. 195-65A. 64 FR 6814, February 11, 1999]

**Appendix C to Part 195–Guidance for Implementation of Integrity Management Program**

This Appendix gives guidance to help an operator implement the requirements of the integrity management program rule in §§ 195.450 and 195.452. Guidance is provided on:

(1) Information an operator may use to identify a high consequence area and factors an operator can use to consider the potential impacts of a release on an area;

(2) Risk factors an operator can use to determine an integrity assessment schedule;

(3) Safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported, an operator may use to determine if a pipeline segment falls into a high, medium or low risk category;

(4) Types of internal inspection tools an operator could use to find pipeline anomalies;

(5) Measures an operator could use to measure an integrity management program's performance; and

(6) Types of records an operator will have to maintain.

(7) Types of conditions that an integrity assessment may identify that an operator

should include in its required schedule for evaluation and remediation.

I. Identifying a high consequence area and factors for considering a pipeline segment's potential impact on a high consequence area.

A. The rule defines a High Consequence Area as a high population area, an other populated area, an unusually sensitive area, or a commercially navigable waterway.

The Office of Pipeline Safety (OPS) will map these areas on the National Pipeline Mapping System (NPMS). An operator, member of the public, or other government agency may view and download the data from the NPMS home page http://www.npms.rspa.dot.gov/.

OPS will maintain the NPMS and update it periodically. However, it is an operator's responsibility to ensure that it has identified all high consequence areas that could be affected by a pipeline segment. An operator is also responsible for periodically evaluating its pipeline segments to look for population or environmental changes that may have occurred around the pipeline and to keep its program current with this information. (Refer to §195.452(d)(3).) For more information to help in identifying high consequence areas, an operator may refer to:

(1) Digital Data on populated areas available on U.S. Census Bureau maps.

(2) Geographic Database on the commercial navigable waterways available on http://www.bts.gov/gis/ntatlas/networks.html.

(3) The Bureau of Transportation Statistics database that includes commercially navigable waterways and non-commercially navigable waterways. The database can be downloaded from the BTS website at http://www.bts.gov/gis/ntatlas/networks.html.

B. The rule requires an operator to include a process in its program for identifying which pipeline segments could affect a high consequence area and to take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. (See §§ 195.452 (f) and (i).) Thus, an operator will need to consider how each pipeline segment could affect a high consequence area. The primary source for the listed risk factors is a US DOT study on instrumented Internal Inspection devices (November 1992). Other sources include the National Transportation Safety Board, the Environmental Protection Agency and the Technical Hazardous Liquid Pipeline Safety Standards Committee. The following list provides guidance to an operator on both the mandatory and additional factors:

(1) Terrain surrounding the pipeline. An operator should consider the contour of the land profile and if it could allow the liquid from a release to enter a high consequence area. An operator can get this information from topographical maps such as U.S. Geological Survey quadrangle maps.

(2) Drainage systems such as small streams and other smaller waterways that could serve as a conduit to a high consequence area.

(3) Crossing of farm tile fields. An operator should consider the possibility of a spillage in the field following the drain tile into a waterway.

(4) Crossing of roadways with ditches along the side. The ditches could carry a spillage to a waterway.

(5) The nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly volatile liquids, etc.) Highly volatile liquids becomes gaseous when exposed to the atmosphere. A

spillage could create a vapor cloud that could settle into the lower elevation of the ground profile.

(6) Physical support of the pipeline segment such as by a cable suspension bridge. An operator should look for stress indicators on the pipeline (strained supports, inadequate support at towers), atmospheric corrosion, vandalism, and other obvious signs of improper maintenance.

(7) Operating conditions of the pipeline (pressure, flow rate, etc.). Exposure of the pipeline to an operating pressure exceeding the established maximum operating pressure.

(8) The hydraulic gradient of the pipeline.

(9) The diameter of the pipeline, the potential release volume, and the distance between the isolation points.

(10) Potential physical pathways between the pipeline and the high consequence area.

(11) Response capability (time to respond, nature of response).

(12) Potential natural forces inherent in the area (flood zones, earthquakes, subsidence areas, etc.)

II. Risk factors for establishing frequency of assessment.

A. By assigning weights or values to the risk factors, and using the risk indicator tables, an operator can determine the priority for assessing pipeline segments, beginning with those segments that are of highest risk, that have not previously been assessed. This list provides some guidance on some of the risk factors to consider (see §195.452(e)). An operator should also develop factors specific to each pipeline segment it is assessing, including:

(1) Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.

(2) Results from previous testing/inspection. (See §195.452(h).)

(3) Leak History. (See leak history risk table.)

(4) Known corrosion or condition of pipeline. (See §195.452(g).)

(5) Cathodic protection history.

(6) Type and quality of pipe coating (disbonded coating results in corrosion).

(7) Age of pipe (older pipe shows more corrosion–may be uncoated or have an ineffective coating) and type of pipe seam. (See Age of Pipe risk table.)

(8) Product transported (highly volatile, highly flammable and toxic liquids present a greater threat for both people and the environment) (see Product transported risk table.)

(9) Pipe wall thickness (thicker walls give a better safety margin)

(10) Size of pipe (higher volume release if the pipe ruptures).

(11) Location related to potential ground movement (e.g., seismic faults, rock quarries, and coal mines); climatic (permafrost causes settlement–Alaska); geologic (landslides or subsidence).

(12) Security of throughput (effects on customers if there is failure requiring shutdown).

(13) Time since the last internal inspection/pressure testing.

(14) With respect to previously discovered defects/anomalies, the type, growth rate, and size.

(15) Operating stress levels in the pipeline.

(16) Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly impede access for spill response or any other purpose).

(17) Physical support of the segment such as by a cable suspension bridge.

(18) Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).

B. Example: This example illustrates a hypothetical model used to establish an integrity assessment schedule for a hypothetical pipeline segment. After we determine the risk factors applicable to the pipeline segment, we then assign values or numbers to each factor, such as, high (5), moderate (3), or low (1). We can determine an overall risk classification (A, B, C) for the segment using the risk tables and a sliding scale (values 5 to 1) for risk factors for which tables are not provided. We would classify a segment as C if it fell above 2/3 of maximum value (highest overall risk value for any one segment when compared with other segments of a pipeline), a segment as B if it fell between 1/3 to 2/3 of maximum value, and the remaining segments as A.

i. For the baseline assessment schedule, we would plan to assess 50% of all pipeline segments covered by the rule, beginning with the highest risk segments, within the first 3½ years and the remaining segments within the seven-year period. For the continuing integrity assessments, we would plan to assess the C segments within the first two (2) years of the schedule, the segments classified as moderate risk no later than year three or four and the remaining lowest risk segments no later than year five (5).

ii. For our hypothetical pipeline segment, we have chosen the following risk factors and obtained risk factor values from the appropriate table. The values assigned to the risk factors are for illustration only.

*Age of pipeline:* assume 30 years old (refer to "Age of Pipeline**"** risk table)–
Risk Value=5

*Pressure tested:* tested once during construction–
Risk Value=5
*Coated*: (yes/no)–yes
*Coating Condition:* Recent excavation of suspected areas showed holidays in coating (potential corrosion risk)–
Risk Value=5
*Cathodically Protected:* (yes/no)–yes–Risk Value=1
*Date cathodic protection installed:* five years after pipeline was constructed (Cathodic protection installed within one year of the pipeline's construction is generally considered low risk.)–Risk Value=3
*Close interval survey:* (yes/no)–no–Risk Value =5
*Internal Inspection tool used:* (yes/no)–yes. Date of pig run? In last five years–Risk Value=1
*Anomalies found:* (yes/no)–yes, but do not pose an immediate safety risk or environmental hazard–Risk Value=3
*Leak History:* yes, one spill in last 10 years. (refer to "Leak History**"** risk table)–Risk Value=2
*Product transported:* Diesel fuel. Product low risk. (refer to "Product**"** risk table)–Risk Value=1
*Pipe size:* 16 inches. Size presents moderate risk (refer to "Line Size**"** risk table)–Risk Value=3

iii. Overall risk value for this hypothetical segment of pipe is 34. Assume we have two other pipeline segments for which we conduct similar risk rankings. The second pipeline segment has an overall risk value of 20, and the third segment, 11. For the baseline assessment we would establish a schedule where we assess the first segment (highest risk segment) within two years, the second segment within five years and the third segment within seven years. Similarly, for the continuing integrity assessment, we

could establish an assessment schedule where we assess the highest risk segment no later than the second year, the second segment no later than the third year, and the third segment no later than the fifth year.

III. Safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported.

| LEAK HISTORY | |
|---|---|
| Safety risk indicator | Leak history (Time-dependent defects)[1] |
| High | > 3 Spills in last 10 years |
| Low | 3 Spills in last 10 years |

[1] Time-dependent defects are those that result in spills due to corrosion, gouges, or problems developed during manufacture, construction or operation, etc.

| LINE SIZE OR VOLUME TRANSPORTED | |
|---|---|
| Safety risk indicator | Line size |
| High | ≥ 18" |
| Moderate | 10"–16" nominal diameters |
| Low | ≤ 8" nominal diameter |
| AGE OF PIPELINE | |
| Safety risk indicator | Age Pipeline condition dependent[1] |
| High | > 25 years |
| Low | 25 years |

[1] Depends on pipeline's coating & corrosion condition, and steel quality, toughness, welding.

| PRODUCT TRANSPORTED | | |
|---|---|---|
| Safety risk indicator | Considerations[1] | Product examples |
| High | (Highly volatile and flammable) | (Propane, butane, Natural Gas Liquid (NGL), ammonia). |
| | Highly toxic | (Benzene, high Hydrogen Sulfide content crude oils). |
| Medium | Flammable<flashpoint 100F | (Gasoline, JP4, low flashpoint crude oils). |
| Low | Non-flammable–flashpoint 100+F | (Diesel, fuel oil, kerosene, JP5, most crude oils). |

[1] The degree of acute and chronic toxicity to humans, wildlife, and aquatic life; reactivity; and, volatility, flammability, and water solubility determine the Product Indicator. Comprehensive Environmental Response, Compensation and Liability Act Reportable Quantity values may be used as an indication of chronic toxicity. National Fire Protection Association health factors may be used for rating acute hazards.

IV. Types of internal inspection tools to use.

An operator should consider at least two types of internal inspection tools for the integrity assessment from the following list. The type of tool or tools an operator selects will depend on the results from previous internal inspection runs, information analysis and risk factors specific to the pipeline segment:

(1) Geometry Internal inspection tools for detecting changes to ovality, e.g., bends, dents, buckles or wrinkles, due to construction flaws or soil movement, or other outside force damage;

(2) Metal Loss Tools (Ultrasonic and Magnetic Flux Leakage) for determining pipe wall anomalies, e.g., wall loss due to corrosion.

(3) Crack Detection Tools for detecting cracks and crack-like features, e.g., stress corrosion cracking (SCC), fatigue cracks, narrow axial corrosion, toe cracks, hook cracks, etc.

V. Methods to measure performance.

A. *General*. (1) This guidance is to help an operator establish measures to evaluate the effectiveness of its integrity management program. The

performance measures required will depend on the details of each integrity management program and will be based on an understanding and analysis of the failure mechanisms or threats to integrity of each pipeline segment.

(2) An operator should select a set of measurements to judge how well its program is performing. An operator's objectives for its program are to ensure public safety, prevent or minimize leaks and spills and prevent property and environmental damage. A typical integrity management program will be an ongoing program and it may contain many elements. Therefore, several performance measure are likely to be needed to measure the effectiveness of an ongoing program.

B. *Performance measures.* These measures show how a program to control risk on pipeline segments that could affect a high consequence area is progressing under the integrity management requirements. Performance measures generally fall into three categories:

(1) Selected Activity Measures– Measures that monitor the surveillance and preventive activities the operator has implemented. These measure indicate how well an operator is implementing the various elements of its integrity management program.

(2) Deterioration Measures–Operation and maintenance trends that indicate when the integrity of the system is weakening despite preventive measures. This category of performance measure may indicate that the system condition is deteriorating despite well executed preventive activities.

(3) Failure Measures–Leak History, incident response, product loss, etc. These measures will indicate progress towards fewer spills and less damage.

C. *Internal vs. External Comparisons.* These comparisons show how a pipeline segment that could affect a high consequence area is progressing in comparison to the operator's other pipeline segments that are not covered by the integrity management requirements and how that pipeline segment compares to other operators' pipeline segments.

(1) Internal–Comparing data from the pipeline segment that could affect the high consequence area with data from pipeline segments in other areas of the system may indicate the effects from the attention given to the high consequence area.

(2) External–Comparing data external to the pipeline segment (e.g., OPS incident data) may provide measures on the frequency and size of leaks in relation to other companies.

D. *Examples.* Some examples of performance measures an operator could use include–

(1) A performance measurement goal to reduce the total volume from unintended releases by -% (percent to be determined by operator) with an ultimate goal of zero.

(2) A performance measurement goal to reduce the total number of unintended releases (based on a threshold of 5 gallons) by ____-% (percent to be determined by operator) with an ultimate goal of zero.

(3) A performance measurement goal to document the percentage of integrity management activities completed during the calendar year.

(4) A performance measurement goal to track and evaluate the effectiveness of the operator's community outreach activities.

(5) A narrative description of pipeline system integrity, including a summary of performance

improvements, both qualitative and quantitative, to an operator's integrity management program prepared periodically.

(6) A performance measure based on internal audits of the operator's pipeline system per 49 CFR Part 195.

(7) A performance measure based on external audits of the operator's pipeline system per 49 CFR Part 195.

(8) A performance measure based on operational events (for example: relief occurrences, unplanned valve closure, SCADA outages, etc.) that have the potential to adversely affect pipeline integrity.

(9) A performance measure to demonstrate that the operator's integrity management program reduces risk over time with a focus on high risk items.

(10) A performance measure to demonstrate that the operator's integrity management program for pipeline stations and terminals reduces risk over time with a focus on high risk items.

VI. Examples of types of records an operator must maintain.

The rule requires an operator to maintain certain records. (See §195.452(l)). This section provides examples of some records that an operator would have to maintain for inspection to comply with the requirement. This is not an exhaustive list.

(1) a process for identifying which pipelines could affect a high consequence area and a document identifying all pipeline segments that could affect a high consequence area;

(2) a plan for baseline assessment of the line pipe that includes each required plan element;

(3) modifications to the baseline plan and reasons for the modification;

(4) use of and support for an alternative practice;

(5) a framework addressing each required element of the integrity management program, updates and changes to the initial framework and eventual program;

(6) a process for identifying a new high consequence area and incorporating it into the baseline plan, particularly, a process for identifying population changes around a pipeline segment;

(7) an explanation of methods selected to assess the integrity of line pipe;

(8) a process for review of integrity assessment results and data analysis by a person qualified to evaluate the results and data;

(9) the process and risk factors for determining the baseline assessment interval;

(10) results of the baseline integrity assessment;

(11) the process used for continual evaluation, and risk factors used for determining the frequency of evaluation;

(12) process for integrating and analyzing information about the integrity of a pipeline, information and data used for the information analysis;

(13) results of the information analyses and periodic evaluations;

(14) the process and risk factors for establishing continual re-assessment intervals;

(15) justification to support any variance from the required re-assessment intervals;

(16) integrity assessment results and anomalies found, process for evaluating and remediating anomalies, criteria for remedial actions and actions taken to evaluate and remediate the anomalies;

(17) other remedial actions planned or taken;

(18) schedule for evaluation and repair of anomalies, justification to support deviation from required repair times;

(19) risk analysis used to identify additional preventive or mitigative measures, records of preventive and mitigative actions planned or taken;

(20) criteria for determining EFRD installation;

(21) criteria for evaluating and modifying leak detection capability;

(22) methods used to measure the program's effectiveness.

VII. Conditions that may impair a pipeline's integrity.

Section 195.452(h) requires an operator to evaluate and remediate all pipeline integrity issues raised by the integrity assessment or information analysis. An operator must develop a schedule that prioritizes conditions discovered on the pipeline for evaluation and remediation. The following are some examples of conditions that an operator should schedule for evaluation and remediation.

A. Any change since the previous assessment.

B. Mechanical damage that is located on the top side of the pipe.

C. An anomaly abrupt in nature.

D. An anomaly longitudinal in orientation.

E. An anomaly over a large area.

F. An anomaly located in or near a casing, a crossing of another pipeline, or an area with suspect cathodic protection.

[Amdt. 195-70, 65 FR 75378, Dec. 1, 2000 as amended by Amdt. 195-74, 67 FR 1650, Jan. 14, 2002; Amdt. 195-94, 75 FR 48593, August 11, 2010]

# AMENDMENTS TO 49 CFR PART 195

| PART 195 AMENDMENT NUMBER | EEFFECTIVE DATE OF AMENDMENT | SECTION IMPACT | IN REFFERENCE TO: |
|---|---|---|---|
| 1 | 4/1/70 | 195.1, .6, .8, .234, .404, .418 | TRANSPORTATION OF CERTAIN COMMODITIES, TESTING RECORDS, INTERNAL CORROSION CONTROL |
| 2 | 11/7/70 | 195.8, .116, .404 | INCORPORATED BY REFERENCE, INTERNAL DESIGN PRESSURE, VALVES, HYDROSTATIC TESTING |
| 2 | 1/8/71 | 195.3, .106, .114, .406, .414, Subpart E (Added) | INCORPORATED BY REFERENCE, INTERNAL DESIGN PRESSURE, VALVES, HYDROSTATIC TESTING |
| 3 | 5/4/71 | 195.306 | TESTING WITH TRANSPORTED COMMODITIES |
| 4 | 10/15/72 | 195.428 | OVERPRESSURE SAFETY DEVICES |
| 5 | 1/30/73 | 195.2, .3, .6, .8, .52, .54, .58, .62, .260 | DEFINITIONS, MATTER INCORPORATED BY REFERENCE |
| 6 | 4/19/73 | 195.52 | TELEPHONIC NOTICE OF CERTAIN ACCIDENTS |
| 7 | 7/15/74 | 195.424 | PIPELINE MOVEMENT CONTAINING LIQUEFIED GASES |
| 8 | 3/20/75 | 195.222, .228 | WELDING REQUIREMENTS |
| 8A | 7/1/75 | 195.222, .228 | WELDING REQUIREMENTS |
| 9 | 7/1/76 | 195.3, .110, .116, .118, .124 | VALVES, FITTINGS, EXTERNAL LOADS, INCORPORATED BY REFERENCE |
| 10 | 7/31/76 | 195.212, .216 | BENDING OF PIPE, WELDING: MITER JOINTS |
| 11 | 11/1/76 | 195.1, .230, .232, .234, .238, .242, .306, .402 | WELDS, EXTERNAL COATING, CATHODIC PROTECTION, VALVES, MANUALS FOR OPERATIONS, MAINTENANCE & EMERGENCIES (ABNORMAL OPERATIONS), TEST MEDIUM |

# AMENDMENTS TO 49 CFR PART 195

| PART 195 AMENDMENT NUMBER | EEFFECTIVE DATE OF AMENDMENT | SECTION IMPACT | IN REFFERENCE TO: |
|---|---|---|---|
| 11 | 8/1/77 | 195.106, .246, .248, .258, .260, .414 | INTERNAL DESIGN PRESSURE, COVER OVER BURIED PIPELINE, VALVES: LOCATION, CATHODIC PROTECTION |
| 11 | 9/30/76 | 195.306 | TEST MEDIUM (CORRECTION) |
| 12 | 10/3/77 | 195.212(a) | LONGITUDINAL SEAMS IN PIPE BENDS |
| 12 | 11/3/77 | 195.212 (b)(3)(B) | CORRECTION |
| 13 | 3/17/78 | 195. 5, .402(d) | GENERAL REQUIREMENTS |
| 14 | 6/1/78 | 195.3(a) & (c)(1)(iv) & (v) | INCORPORATED BY REFERENCE |
| 15 | 7/15/80 | 195.2, .50, .401, .402, .403, .408, .440, .424, .428, Subpart F | DEFINITIONS, PROCEDURAL MANUAL FOR OPERATIONS, MAINTENANCE, & EMERGENCIES |
| 16 | 7/15/80 | 195.401, .402(c)(4)(5), .402(d)(2) | PROCEDURAL MANUAL FOR OPERATIONS, MAINTENANCE & EMERGENCIES |
| 16 | 7/15/81 | 195.402(c)(8)(9) | FAIL SAFE EQUIPMENT |
| 17 | 10/8/80 | 195.300, .302, .406 | MAXIMUM OPERATING PRESSURE (HVL PIPELINES) |
| 18 | 9/8/80 | 195.302 | GENERAL REQUIREMENTS |
| 19 | 9/8/80 | 195.218 | REVOKED |
| 20 | 2/2/81 | 195.418 | INTERNAL CORROSION CONTROL |
| 20A | 6/30/81 | 195.418 | MONITORING OF ANHYDROUS AMMONIA WATER CONTENT |
| 20B | 6/29/81 | 195.418(e) | REVOKED & REMOVED |
| 21 | 3/4/81 | 195.3, .118, .222, .228, .406 | INCORPORATED BY REFERENCE, INTERNAL DESIGN PRESSURE, FITTINGS |

# AMENDMENTS TO 49 CFR PART 195

| PART 195 AMENDMENT NUMBER | EEFFECTIVE DATE OF AMENDMENT | SECTION IM-PACT | IN REFFERENCE TO: |
|---|---|---|---|
| 22 | 7/27/81 | PART 195 | CONFIRMATION & ISSU-ANCE AUTHORITY OF HLPSA OF 1979 |
| 22 | 7/29/82 | PART 195 | TECHNICAL CORRECTIONS |
| 23 | 10/27/82 | 195.52, .54, .58, .62 | TELEPHONIC NOTICE OF CERTAIN ACCIDENTS |
| 24 | 11/22/82 | 195.402, .403, .412, .416, .418, .420, .428, .432 | TRAINING, INSPECTION OF ROW & CROSSINGS UNDER NAVIGABLE WATERS, COR-ROSION CONTROL, BREAKOUT TANKS |
| 25 | 1/10/83 | 195.220 | REMOVED |
| 26 | 1/4/83 | 195.234 | 195.234(g) REMOVED |
| 27 | 7/6/83 | 195.410 | LINE MARKERS |
| 28 | 8/4/83 | 195.101 | QUALIFYING METALLIC COMPONENTS OTHER THAN PIPE |
| 29 | 11/21/83 | 195.230, .232 | WELDS: REPAIR OR RE-MOVAL OF DEFECTS, 195.232 REMOVED |
| 30 | 4/2/84 | 195.106 | INTERNAL DESIGN PRES-SURE |
| 31 | 10/17/84 | 195.416(g) | EXTERNAL CORROSION CONTROL |
| 32 | 10/22/84 | 195.3, .222 | WELDERS: TESTING, IN-CORPORATED BY REFER-ENCE |
| 33 | 10/21/85 | 195.1, .2, .300, .302, .401, .406, .414 | MAXIMUM OPERATING PRESSURE, CATHODIC PRO-TECTION |
| 33 | 4/23/87 | 195.402 | FOR INTRASTATE LINES - PROCEDURAL MANUAL FOR OPERATING MAINTE-NANCE & EMERGENCIES (INTRASTATE PIPELINES) |
| 33 | 9/24/85 | 195.2, .302, .406, .414 | GRAMMATICAL CORREC-TIONS |

# AMENDMENTS TO 49 CFR PART 195

| PART 195 AMENDMENT NUMBER | EEFFECTIVE DATE OF AMENDMENT | SECTION IMPACT | IN REFFERENCE TO: |
|---|---|---|---|
| 33A | 9/28/85 | 195.401(c)(3) | (10/21/85 CORRECTED TO 10/20/85) |
| 33B | 11/1/85 | Through out | REFERENCE CHANGE FROM MTB TO OPS |
| 34 | 10/21/85 | 195.1(c), .54, .56, .58, .63, .266, .310, .404 | ACCIDENT REPORTING APPLICABILITY, CONSTRUCTION RECORDS, MAPS & RECORDS |
| 35 | 10/15/85 | 195.234 | WELDS: NONDESTRUCTIVE TESTING |
| 35 | 10/21/85 | 195.234 | EFFECTIVE DATE FOR INTRASTATE HAZARDOUS LIQUID PIPELINES |
| 36 | 8/20/86 | 195.1, .2, .401 | APPLICABILITY, DEFINITIONS |
| 37 | 5/23/86 | 195.3, .106 | INTERNAL DESIGN PRESSURE |
| 38 | 7/7/86 | 195.214, .222 | WELDING: QUALIFICATION OF WELDERS |
| 39 | 9/29/88 | 195.50, .54, .55, .56, .58, .402 | HAZARDOUS CONDITIONS |
| 40 | 3/8/89 | 195.3, .106 | REMOVING & UPDATING SOME VOLUNTARY SPECIFICATIONS |
| 41 | 8/2/89 | 195.3 | UPDATES API 1104 TO 17TH EDITION (1988) |
| 42 | 8/7/89 | 195.56 | CLARIFIES "SAFETY RELATED CONDITION" REPORTING REQUIREMENT |
| 43 | 9/6/89 | 195.3 | UPDATE API 5L TO 1988 EDITION |
| 44 | 10/4/89 | 195.52(b) | TELEPHONE NUMBER CHANGE FOR REPORTING INCIDENTS & ACCIDENTS |
| 44 | 10/9/89 | 195.56(a) | SAFETY RELATED CONDITIONS |

# AMENDMENTS TO 49 CFR PART 195

| PART 195 AMENDMENT NUMBER | EEFFECTIVE DATE OF AMENDMENT | SECTION IM-PACT | IN REFFERENCE TO: |
|---|---|---|---|
| 45 | 7/12/91 | 195.0, .1, .2, .4, .8, .50, .52, .102, .111, .116, .306, .401, .402, .403, .410, .414, .418, .440 | CARBON DIOXIDE PIPE-LINES SUBJECT TO PART 195 |
| 46 | 8/8/91 | 195.402(b) | ALLOWS FOR ENFORCE-MENT ACTIONS FOR INAD-EQUATE PLANS & PROCE-DURES |
| 47 | 1/6/92 | 195.1, .2, .57, .413 | INSPECTION & BURIAL OF OFFSHORE PIPELINES IN THE GULF OF MEXICO |
| 48 | 4/19/93 | 195.3, .106, .110, .118 | UPDATES EXISTING REFER-ENCES TO VOLUNTARY SPECIFICATIONS & STAND-ARDS |
| 49 | 3/14/94 | 195.402 | EXCAVATED TRENCHES |
| 50 | 5/12/94 | 195.2, .8, .56, .58, .106, .120, .260 | INTERNAL INSPECTION DE-VICES, TECHNICAL COR-RECTION |
| 51 | 7/7/94 | 195.406(a)(5) Subpart E | PRESSURE TESTING OLDER LIQUID & $CO_2$, MOP |
| 51 | 8/8/94 | 195.306(b) | USE OF PETROLEUM AS TEST MEDIUM |
| 51A | 8/11/94 | 195.306(b) | TEST MEDIUM (PARTIAL WITHDRAWAL) |
| 51B | 8/20/96 | 195.302 | EXTENSION OF TIME FOR PRESSURE TESTING |
| 52 | 7/28/94 | 195.1, .2, .3, .5, .50(f), .52(a)(3), .106(b), .106(c), .112(c), .204, .212(b)(3)(ii), .228(b), .234, .246, .248, .262(d), .304(b), .406, .412(a), .413(a), .416 | AMENDMENTS TO PROVIDE CLARITY, ELIMINATE UN-NECESSARY & OVERLY BURDENSOME REGULA-TIONS & FOSTER ECONO-MIC GROWTH |

# AMENDMENTS TO 49 CFR PART 195

| PART 195 AMENDMENT NUMBER | EEFFECTIVE DATE OF AMENDMENT | SECTION IM-PACT | IN REFFERENCE TO: |
|---|---|---|---|
| 53 | 8/11/94 | 195.1, .2, .302, .306, .401, .414 | TRANSPORTATION OF HAZARDOUS LIQUIDS AT 20 PERCENT OR LESS OF SPECIFIED MINIMUM YIELD STRENGTH |
| 54 | 4/19/95 | 195.410(a)(2) & (b)(2)(i), .442 | ESTABLISHES EXCAVATION DAMAGE PREVENTION PROGRAM REQUIREMENTS & PERMITS SMALLER LETTERING ON CERTAIN LINE MARKERS |
| 55 | 4/26/96 | 195.58, .402 | ANHYDROUS AMMONIA, CARBON DIOXIDE, PETROLEUM, REPORTING & RECORD KEEPING REQUIREMENTS |
| 56 | 6/24/96 | 195.3 | ANHYDROUS AMMONIA, CARBON DIOXIDE, INCORPORATION BY REFERENCE |
| 56A | 8/14/96 | 195.3 | ADDRESS CORRECTION |
| 57 | 10/7/97 | 195.1 | LOW-STRESS PIPELINES |
| 57A | 10/7/97 | 195.1 | WITHDRAWAL OF DIRECT FINAL RULE |
| 58 | 1/20/98 | 195.302 | NEW COMPLIANCE DATES |
| 59 | 3/17/98 | 195.1, .2, .9 | OFFSHORE TRANSFER POINTS, ADDED 195.9 |
| 60 | 5/18/98 | 195.442 | MANDATORY PARTICIPATION IN A ONE CALL SYSTEM |
| 61 | 5/4/98 | 195.3, .56 | INCORPORATION BY REFERENCE, SAFETY-RELATED CONDITION REPORTS |
| 62 | 7/6/99 | 195.2, .3, .134, .444 | ADOPTION OF API 1130, COMPUTATIONAL PIPELINE MONITORING, ADDED 195.134 & .444 |
| 63 | 7/13/98 | Inclusive | METRIC EQUIVALENTS |
| 64 | 10/2/98 | 195.1 | LOW-STRESS PIPELINES |
| 65 | 11/4/98 | 195.302, .304, .305, .406, App. B | RISK BASED ALTERNATIVES TO PRESSURE TEST |

# AMENDMENTS TO 49 CFR PART 195

| PART 195 AMENDMENT NUMBER | EEFFECTIVE DATE OF AMENDMENT | SECTION IM-PACT | IN REFFERENCE TO: |
|---|---|---|---|
| 65A | 2/11/99 | App. B, Table 4 | CORRECTED REFERENCE IN TABLE 4 |
| 66 | 5/3/99 | 195.1, .3, .132, .205, .242, .264, .307, .405, .416, .428, .432 | ADOPTION OF STANDARDS FOR BREAKOUT TANKS |
| 66A | 2/1/00 | 195.3 | CORRECTION OF API 653 STANDARD |
| 67 | 10/26/99 | Subpart G | OPERATOR QUALIFICATION |
| 67 | 10/28/02 | 195.403, | TRAINING |
| 68 | 1/13/00 | 195.416 | PIPELINE REPAIR |
| 69 | 10/10/00 | 195.2, .59, .402 | ABANDONED UNDERWA-TER FACILITIES |
| 70 | 12/31/01, 03/31/2001, 03/31/2002 | TOC, 195.450, .452, App. C | PIPELINE INTEGRITY MAN-AGEMENT |
| 71 | 02/20/01 | 195.2, .6 | AREAS UNUSUALY SENSI-TIVE TO ENVIRONMENTAL DAMAGE |
| 72 | 07/20/01 | 195.503, .509 | QUALIFICATION OF PIPE-LINE PERSONNEL |
| 73 | 01/28/02 | 195.3, .5, .402, .404, .236, .238, .242, .244, .414, .416, .416, .418, SUBPART H | CONTROLLING CORROSION |
| 73A | 11/20/02 | 195.573(c) | CORRECTED TABLE |
| 74 | 05/29/02 | 195.452, Appen-dix C | REPAIR CRITERIA, PIPELINE INTEGRITY MANAGEMENT |
| 75 | 01/01/02 | 195.50 | REPORTING REQUIRE-MENTS |
| 76 | 02/15/02 | 195.452 | PIPELINE INTEGRITY FOR HAZARDOUS LIQUID OPER-ATORS WITH LESS THAN 500 MILES. |
| 76a | 02/15/02 | 195.452(d)(2) | CORRECTION OF DATE |
| 77 | 03/12/03 | 195.2 | DEFINITION OF ADMINIS-TRATOR |
| 78 | 09/04/03 | 195.1 | OFFSHORE PIPELINES IN STATE WATERS |

# AMENDMENTS TO 49 CFR PART 195

| PART 195 AMENDMENT NUMBER | EEFFECTIVE DATE OF AMENDMENT | SECTION IMPACT | IN REFFERENCE TO: |
|---|---|---|---|
| 79 | 10/14/2003 | 195.222, .252, 310, .40, 434 | NAPSR MISCELLANEOUS RECOMMENDATIONS |
| 80 | 02/05/04 | 195.49 | ANNUAL REPORT REQUIREMENTS |
| 81 | 07/14/04 | 195.2, .3, .58, .214, .222, .228 | ADOPTION OF NEW STANDARDS |
| 81A | 07/14/04 | 195.222 | CORRECTION TO 192-81 |
| 82 | 09/09/04 | 195.2, .246, .248, .413 | PERIODIC UNDERWATER INSPECTION |
| 84 | 07/01/05 | 195.505, .509 | STATUTORY CHANGES |
| No Number | 03/08/05 | 195.1, .2, .9, .57, .58, .59, .452 | ADMINISTRATION NAME CHANGE |
| 84 | 06/20/05 | 195.3, .440 | PUBLIC AWARENESS PROGRAMS |
| 85 | 11/25/05 | 195.3, 452, .553, .588 | STANDARDS FOR DIRECT ASSESSMENT |
| 86 | 07/10/06 | 195..3, .116, .214, .222, .228, .264, .307, .440, .571, .573 | UPDATE INCORPORATED BY REFERENCE |
| 86c | 03/05/07 | 195.59 | UPDATE OF WEBSITE INFO AND REMOVAL OF DEAD LINE DATES |
| 87 | 08/16/07 | 195.452 | MODIFICATIONS AND CLARIFICATIONS FOR IMP |
| [88] | 04/28/08 | 195.3, .57, .59, .452 | ADMINISTRATIVE PROCEDURES, UPDATES AND TECHNICAL AMENDMENTS |
| [89] | 07/03/08 | 195.1, .11, .12, .48, .452 | PROTECTING UNUSUALLY SENSITIVE AREAS FROM RURAL ONSHORE HAZARDOUS LIQUID GATHERING LINES AND LOW-STRESS LINES |
| [90] | 02/17/09 | 195.3, .52, .57, .58, .59, .62 | ADMINISTRATIVE PROCEDURES, ADDRESS UPDATES, AND TECHNICAL AMENDMENTS |
| [91] | 04/21/09 | 195.3 | INCORPORATION BY REFERENCE UPDATE: AMERICAN PETROLEUM INSTITUTE (API) STANDARDS 5L AND 1104 |
| 92 | 01/29/10 | 195.12 | EDITORIAL AMENDMENTS TO THE PIPELINE SAFETY REGULATIONS |

# AMENDMENTS TO 49 CFR PART 195

| PART 195 AMENDMENT NUMBER | EEFFECTIVE DATE OF AMENDMENT | SECTION IM-PACT | IN REFFERENCE TO: |
|---|---|---|---|
| 93 | 02/01/10 | 195.2, .3, .402, .446 | CONTROL ROOM MANAGE-MENT/HUMAN FACTORS |
| 93c | 02/01/10 | 195.446 | CORRECTION |
| 94 | 10/01/10 | | PERIODIC UPDATES OF REGULA-TORY REFERENCES TO TECH-NICAL STANDARDS AND MISCEL-LANEOUS EDITS |
| 95 | 11/26/2010 | 195.48, 49, 52, 54, 58, 62, 63, 64, | UPDATES TO PIPELINE AND LIQ-UEFIED NATURAL GAS REPORT-ING REQUIREMENTS |
| 96 | 05/05/11 | 195.1, 12, 48 | APPLYING SAFETY REGULATIONS TO ALL RURAL ONSHORE HAZ-ARDOUS LIQUID LOW-STRESS LINES |
| 96c | 07/21/11 | 195.12 | APPLYING SAFETY REGULATIONS TO ALL RURAL ONSHORE HAZ-ARDOUS LIQUID LOW-STRESS LINES |
| 97 | 6/16/11 | 195.446 | CONTROL ROOM MANAGEMENT/HUMAN FACTORS |

# Report Forms

Notice: This report is required by 49 CFR Part 195. Failure to report may result in a civil penalty not to exceed $100,000 for each violation for each day the violation continues up to a maximum of $1,000,000 as provided in 49 USC 60122.

Form Approved
OMB No. 2137-0614
Expires: 01/31/2014

| U.S. Department of Transportation<br>Pipeline and Hazardous Materials<br>Safety Administration | **ANNUAL REPORT FOR CALENDAR YEAR 20___<br>HAZARDOUS LIQUID PIPELINE SYSTEMS** | INITIAL REPORT ☐<br>SUPPLEMENTAL REPORT ☐ |
|---|---|---|

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0614. Public reporting for this collection of information is estimated to be approximately 18 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

***Important:*** *Please read the separate instructions for completeing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline.*

| **PART A - OPERATOR INFORMATION** | DOT USE ONLY | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|

1. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (OPID)

/___/___/___/___/___/

2. NAME OF COMPANY OR ESTABLISHMENT:

_____

IF SUBSIDIARY, NAME OF PARENT:

_____

3. INDIVIDUAL WHERE ADDITIONAL INFORMATION MAY BE OBTAINED:

_____
Name

_____
Title

_____
Email Address

/__/__/__/-/__/__/__/-/__/__/__/__/
Telephone Number

4. HEADQUARTERS ADDRESS:

_____
Company Name

_____
Street Address

State: /___/___/ Zip Code: /__/__/__/__/__/ - /__/__/__/__/

/__/__/__/-/__/__/__/-/__/__/__/__/
Telephone Number

5. THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP: *(Select Commodity Group based on the predominant commodity carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)*

☐ Crude Oil

☐ Refined and/or Petroleum Product (non-HVL)

☐ HVL

☐ $CO_2$

☐ Fuel Grade Ethanol (dedicated system)

6. CHARACTERIZE THE PIPELINES AND/OR PIPELINE FACILITIES COVERED BY THIS OPID AND COMMODITY GROUP WITH RESPECT TO COMPLIANCE WITH PHMSA'S INTEGRITY MANAGEMENT PROGRAM REGULATIONS (49 CFR 195.452). *(Select only one)*

☐ NO portions of the pipelines and/or pipeline facilities covered by this OPID and Commodity Group are included in an Integrity Management Program subject to 49 CFR 195. If this box is checked, leave PARTs B, F, G, L, and O blank, but complete all remaining PARTs of this form in accordance with PART A, Question 8**.**

☐ Portions of SOME or ALL of the pipelines and/or pipeline facilities covered by this OPID and Commodity Group are included in an Integrity Management Program subject to 49 CFR 195. If this box is checked, complete all PARTs of this form in accordance with PART A, Question 8**.**

7. FOR THE DESIGNATED COMMODITY GROUP, THE PIPELINES AND/OR PIPELINE FACILITIES INCLUDED WITHIN THIS OPID ARE: *(Select one or both)*

☐ INTERstate pipeline → List all of the States in which INTERstate pipelines and/or pipeline facilities included under this OPID exist: __, __, __, __, __, etc.

☐ INTRAstate pipeline → List all of the States in which INTRAstate pipelines and/or pipeline facilities included under this OPID exist: __, __, __, __, __, etc.

8. DOES THIS REPORT REPRESENT A CHANGE FROM LAST YEAR'S FINAL REPORTED NUMBERS FOR ONE OR MORE OF THE FOLLOWING PARTs: PART B, D, E, H, I, J, K, L, or M? *(For calendar year 2010 reporting or if this is a first-time Report for an operator or OPID, Commodity Group(s), or pipelines and/or pipeline facilities, select the first box only. For subsequent years' reporting, select either No or one or both of the Yes choices.)*

☐ This report is **FOR CALENDAR YEAR 2010** reporting **or is a FIRST-TIME REPORT** and, therefore, *the remaining choices in this Question 8 do not apply*. Complete all remaining PARTS of this form as applicable.

☐ NO, there are **NO CHANGES** from last year's final reported information for PARTs B, D, E, H, I, J, K, L, or M. Complete PARTs A, C, and N, along with PARTs F, G, and O when applicable.

☐ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for one or more of PARTs B, D, E, H, I, J, K, L, or M ***due to corrected information****; however, the pipelines and/or pipeline facilities and operations are the same* as those which were covered under last year's report. Complete PARTs A, C, and N, along with only those other PARTs which changed (including PARTs B, F, G, L, and O when applicable).

☐ YES, this report represents a **CHANGE FROM LAST YEAR'S FINAL REPORTED INFORMATION** for PARTs B, D, E, H, I, J, K, L, or M because of one or more of the following ***change(s) in pipelines and/or pipeline facilities and/or operations*** from those which were covered under last year's report. Complete PARTs A, C, and N, along with only those other PARTs which changed (including PARTs B, F, G, L, and O when applicable). *(Select all reasons for these changes from the following list)*

☐ Merger of companies and/or operations, acquisition of pipelines and/or pipeline facilities
☐ Divestiture of pipelines and/or pipeline facilities
☐ New construction or new installation of pipelines and/or pipeline facilities
☐ Conversion of service, change in commodity transported, or change in MOP (maximum operating pressure).
☐ Abandonment of existing pipelines and/or pipeline facilities
☐ Change in HCA's identified, pipeline facilities or segments that could affect HCAs, or other changes to Operator's Integrity Management Program
☐ Change in OPID
☐ Other → Describe: _____

Form Approved
OMB No. 2137-0614
Expires: 01/31/2014

***For the designated Commodity Group, complete PARTs B, C, D, and E one time for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate - included within this OPID.***

| **PART B - MILES OF PIPE BY LOCATION** | |
|---|---|
| | Total Segment Miles That Could Affect HCAs |
| **Onshore** | |
| **Offshore** | |
| Total Miles | *Calc* |

| **PART C - VOLUME TRANSPORTED IN BARREL-MILES** *(include Commodities within this Commodity Group that are not predominant)* | | |
|---|---|---|
| | **Onshore** | **Offshore** |
| Crude Oil | | |
| Refined and/or Petroleum Product (non-HVL) | | |
| HVL | | |
| $CO_2$ | | |
| Fuel Grade Ethanol (dedicated system) | | |

| **PART D - MILES OF STEEL PIPE BY CORROSION PROTECTION** | | | | | |
|---|---|---|---|---|---|
| | Cathodically protected | | Cathodically unprotected | | Total Miles |
| | Bare | Coated | Bare | Coated | |
| **Onshore** | | | | | *Calc* |
| **Offshore** | | | | | *Calc* |
| Total Miles | *Calc* | *Calc* | *Calc* | *Calc* | *Calc* |

| **PART E - MILES OF ELECTRIC RESISTANCE WELDED (ERW) PIPE BY WELD TYPE AND DECADE** | | | | | | |
|---|---|---|---|---|---|---|
| Decade Pipe Installed | Pre-40 or Unknown | 1940 -1949 | 1950 - 1959 | 1960 - 1969 | 1970 - 1979 | 1980 - 1989 |
| **High Frequency** | | | | | | |
| **Low Frequency and DC** | | | | | | |
| Total Miles | *Calc* | *Calc* | *Calc* | *Calc* | *Calc* | *Calc* |
| Decade Pipe Installed | 1990 - 1999 | 2000 – 2009 | 2010 - 2019 | | | Total Miles |
| **High Frequency** | | | | | | *Calc* |
| **Low Frequency and DC** | | | | | | *Calc* |
| Total Miles | *Calc* | *Calc* | *Calc* | | | *Calc* |

***For the designated Commodity Group, complete PARTs F and G <u>one time for all INTERstate pipelines and/or pipeline facilities</u> included within this OPID and multiple times as needed for the designated Commodity Group <u>for each State in which INTRAstate pipelines and/or pipeline facilities</u> included within this OPID exist. Each time these sections are completed, designate the State to which the data applies for INTRAstate pipelines and/or pipeline facilities, or that it applies to all INTERstate pipelines included within this Commodity Group and OPID.***

**PARTs F and G**

**The data reported in these PARTs F and G applies to:** *(select only one)*

☐ **Interstate pipelines/pipeline facilities**

☐ **Intrastate pipelines/pipeline facilities in the State of /__/__/** *(complete for each State)*

| **PART F - INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION** | |
|---|---|
| **1. MILEAGE INSPECTED IN CALENDAR YEAR USING THE FOLLOWING IN-LINE INSPECTION (ILI) TOOLS** | |
| a. Corrosion or metal loss tools | |
| b. Dent or deformation tools | |
| c. Crack or long seam defect detection tools | |
| d. Any other internal inspection tools | |
| e. Total tool mileage inspected in calendar year using in-line inspection tools. (Lines a + b + c + d ) | *Calc* |
| **2. ACTIONS TAKEN IN CALENDAR YEAR BASED ON IN-LINE INSPECTIONS** | |
| a. Based on ILI data, total number of anomalies excavated in calendar year because they met the operator's criteria for excavation. | |
| b. Total number of anomalies repaired in calendar year that were identified by ILI based on the operator's criteria, both within a segment that could affect an HCA and outside of a segment that could affect an HCA. | |
| c. Total number of conditions repaired WITHIN A SEGMENT THAT COULD AFFECT AN HCA meeting the definition of: | *Calc* |
| 1. "Immediate repair condition" [195.452(h)(4)(i)] | |
| 2. "60-day condition" [195.452(h)(4)(ii)] | |
| 3. "180-day condition" [195.452(h)(4)(iii)] | |
| **3. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON PRESSURE TESTING** | |
| a. Total mileage inspected by pressure testing in calendar year. | |
| b. Total number of pressure test failures (ruptures and leaks) repaired in calendar year, both within a segment that could affect an HCA and outside of a segment that could affect an HCA. | |
| c. Total number of pressure test ruptures (complete failure of pipe wall) repaired in calendar year WITHIN A SEGMENT THAT COULD AFFECT AN HCA . | |
| d. Total number of pressure test leaks (less than complete wall failure but including escape of test medium) repaired in calendar year WITHIN A SEGMENT THAT COULD AFFECT AN HCA. | |

*(PART F continued)*

| **4. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON ECDA (EXTERNAL COROSION DIRECT ASSESSMENT)** | |
|---|---|
| a. Total mileage inspected by ECDA in calendar year. | |
| b. Total number of anomalies identified by ECDA and repaired in calendar year based on the operator's criteria, both within a segment that could affect an HCA and outside of a segment that could affect an HCA. | |
| c. Total number of conditions repaired in calendar year WITHIN A SEGMENT THAT COULD AFFECT AN HCA meeting the definition of: | *Calc* |
| 1. "Immediate repair condition" [195.452(h)(4)(i)] | |
| 2. "60-day condition" [195.452(h)(4)(ii)] | |
| 3. "180-day condition" [195.452(h)(4)(iii)] | |
| **5. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON OTHER INSPECTION TECHNIQUES** | |
| a. Total mileage inspected by inspection techniques other than those listed above in calendar year. | |
| b. Total number of anomalies identified by other inspection techniques and repaired in calendar year based on the operator's criteria, both within a segment that could affect an HCA and outside of a segment that could affect an HCA. | |
| c. Total number of conditions repaired in calendar year WITHIN A SEGMENT THAT COULD AFFECT AN HCA meeting the definition of: | *Calc* |
| 1. "Immediate repair condition" [195.452(h)(4)(i)] | |
| 2. "60-day condition" [195.452(h)(4)(ii)] | |
| 3. "180-day condition" [195.452(h)(4)(iii)] | |
| **6. TOTAL MILEAGE INSPECTED (ALL METHODS) AND ACTIONS TAKEN IN CALENDAR YEAR** | |
| a. Total mileage inspected in calendar year. (Lines 1.e + 3.a + 4.a + 5.a) | *Calc* |
| b. Total number of anomalies repaired in calendar year both within a segment that could affect an HCA and outside of a segment that could affect an HCA. (Lines 2.b + 3.b + 4.b + 5.b) | *Calc* |
| c. Total number of conditions repaired in calendar year WITHIN A SEGMENT THAT COULD AFFECT AN HCA. (Lines 2.c.1 + 2.c.2 + 2.c.3 + 3.c + 3.d + 4.c.1 + 4.c.2 + 4.c.3 + 5.c.1 + 5.c.2 + 5.c.3) | *Calc* |

| **PART G – MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS COMPLETED IN CALENDAR YEAR (segment miles that could affect HCAs ONLY)** | |
|---|---|
| a. Baseline assessment miles completed during the calendar year. | |
| b. Reassessment miles completed during the calendar year. | |
| c. Total assessment and reassessment miles completed during the calendar year. | *Calc* |

***For the designated Commodity Group, complete PARTs H, I, J, K, L, and M covering INTERstate pipelines and/or pipeline facilities for each State in which INTERstate systems exist within this OPID and again covering INTRAstate pipelines and/or pipeline facilities for each State in which INTRAstate systems exist within this OPID.***

**PARTs H, I, J, K, L, and M**

**The data reported in these PARTs H, I, J, K, L, and M applies to:** ***(select only one)***

☐ **Interstate pipelines/pipeline facilities in the State of /__/__/** *(complete for each State)*

☐ **Intrastate Pipelines/pipeline facilities in the State of /__/__/** *(complete for each State)*

**PART H - MILES OF PIPE BY NOMINAL PIPE SIZE (NPS)**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Onshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
| | | | | | | | | | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| | | | | | | | | | |
| | 42" | 44" | 46" | 48" | 52" | 56" | 58" and over | Other Pipe Sizes Not Listed | |
| | | | | | | | | Size: __ Miles: _____ *Add Sizes as needed* | |
| *Calc* | Total Miles of Onshore Pipe | | | | | | | | |
| **Offshore** | NPS 4" or less | 6" | 8" | 10" | 12" | 14" | 16" | 18" | 20" |
| | | | | | | | | | |
| | 22" | 24" | 26" | 28" | 30" | 32" | 34" | 36" | 38" |
| | | | | | | | | | |
| | 42" | 44" | 46" | 48" | 52" | 56" | 58" and over | Other Pipe Sizes Not Listed | |
| | | | | | | | | Size: __ Miles: _____ *Add Sizes as needed* | |
| *Calc* | Total Miles of Offshore Pipe | | | | | | | | |

**PART I - MILES OF PIPE BY DECADE INSTALLED**

| Pre-20 or Unknown | 1920 -1929 | 1930 -1939 | 1940 -1949 | 1950 – 1959 | 1960 – 1969 | 1970 – 1979 | 1980 – 1989 |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| 1990 - 1999 | 2000 - 2009 | 2010 - 2019 | | | | | Total Miles |
| | | | | | | | *Calc* |

**PART J - MILES OF PIPE BY SPECIFIED MINIMUM YIELD STRENGTH**

| | Pipeline Segments Subject to ALL 49 CFR 195 Requirements | | | Rural Low-Stress Pipeline Segments Subject ONLY to Subpart B of 49 CFR 195 | Total Miles |
|---|---|---|---|---|---|
| | Onshore | | Offshore | | |
| **Steel Pipe - Operating at greater than 20% SMYS** | | | | | *Calc* |
| | Non-Rural Onshore | Rural Onshore | Offshore | | |
| **Steel Pipe - Operating at less than or equal to 20% SMYS** | | | | | *Calc* |
| **Steel Pipe - Operating at an unknown stress level** | | | | | *Calc* |
| **Non-Steel Pipe - Operating at greater than 125 psig** | | | | | *Calc* |
| **Non-Steel Pipe - Operating at less than or equal to 125 psig** | | | | | *Calc* |
| Total Miles | *Calc* | | *Calc* | *Calc* | *Calc* |

**PART K - MILES OF REGULATED GATHERING LINES**

| | Non-Rural Onshore | Rural Onshore | Offshore | Total Miles |
|---|---|---|---|---|
| **Steel Pipe - Operating at greater than 20% SMYS** | | | | *Calc* |
| **Steel Pipe - Operating at less than or equal to 20% SMYS** | | | | *Calc* |
| **Non-Steel Pipe - Operating at greater than 125 psig** | | | | *Calc* |
| **Non-Steel Pipe - Operating at less than or equal to 125 psig** | | | | *Calc* |
| Total Miles | *Calc* | *Calc* | *Calc* | *Calc* |

**PART L – TOTAL SEGMENT MILES THAT COULD AFFECT HCAs**

| | BY TYPE OF HCA | | | | | NOT BY TYPE |
|---|---|---|---|---|---|---|
| | POPULATION AREAS | | USAs | | COMMERCIALLY NAVIGABLE WATERWAYS | TOTAL SEGMENT MILES THAT COULD AFFECT HCA'S |
| | High Population | Other Population | Drinking Water | Ecological Resource | | |
| **Onshore** | | | | | | |
| **Offshore** | | | | | | |

**PART M - BREAKOUT TANKS**

| Commodity Group | Total Number of Tanks Less than or equal to 50,000 Bbls | Total Number of Tanks 50,001 to 100,000 Bbls | Total Number of Tanks 100,001 to 150,000 Bbls | Total Number of Tanks Over 150,000 Bbls | Total Number of Tanks |
|---|---|---|---|---|---|
| Crude Oil | | | | | *Calc* |
| Refined and/or Petroleum Product (non-HVL) | | | | | *Calc* |
| HVL | | | | | *Calc* |
| $CO_2$ | | | | | *Calc* |
| Fuel Grade Ethanol (dedicated system) | | | | | *Calc* |

***For the designated Commodity Group, complete PART N one time for all of the pipelines and/or pipeline facilities included within this OPID, and then also PART O if any portion(s) of the pipelines and/or pipeline facilities covered under this Commodity Group and OPID are included in an Integrity Management Program subject to 49 CFR 195.***

**PART N - PREPARER SIGNATURE (applicable to all PARTs A - M)**

Preparer's Name (type or print)

/__/__/__/-/__/__/__/-/__/__/__/__/
Telephone Number

Preparer's Title

/__/__/__/-/__/__/__/-/__/__/__/__/
Facsimile Number

Preparer's E-mail Address

**PART O - CERTIFYING SIGNATURE (applicable only to PARTs B, F, G, and L)**

Senior Executive Officer's signature certifying the information in PARTs B, F, G, and L as required by 49 U.S.C. 60109(f)

/__/__/__/-/__/__/__/-/__/__/__/__/
Telephone Number

Senior Executive Officer's name certifying the information in PARTs B, F, G, and L as required by 49 U.S.C. 60109(f)

Senior Executive Officer's title certifying the information in PARTs B, F, G, and L as required by 49 U.S.C. 60109(f)

Senior Executive Officer's E-mail Address

# GENERAL INSTRUCTIONS

All section references are to Title 49 of the Code of Federal Regulations (49 CFR). The Hazardous Liquid or Carbon Dioxide Pipeline Systems Annual Report has been revised as of calendar year 2010 affecting submissions for 2010 and beyond. This Annual Report is required per §195.49 and must be filed per §195.58. Read through the Annual Report and instructions carefully before beginning to complete the Report. Where common data elements exist between this Report and an operator's NPMS submission, the data submitted by the operator on their Annual Report should be the same as the data submitted through NPMS when possible. (Additionally, and in order to align an operator's NPMS submission with their Annual Report data, PHMSA suggests that operators send their NPMS submission to PHMSA by June 15, representing pipeline assets as of December 31 of the previous year.)

Each operator must annually complete and submit DOT Form PHMSA F 7000–1.1 for each type of hazardous liquid pipeline facility operated at the end of the previous year. An operator must submit the annual report by June 15 each year, except that for the 2010 reporting year the report must be submitted by August 15, 2011. A separate report is required for crude oil, HVL (including anhydrous ammonia), petroleum products, carbon dioxide pipelines, and fuel grade ethanol pipelines. For each state a pipeline traverses, an operator must separately complete those sections on the form requiring information to be reported for each state. In order to improve the accuracy of reported data, operators are requested to review prior years' Reports in order to validate that their reported numbers are accurate, or to identify and correct inconsistencies or errors that are either found or that may exist in any previously reported data. Operators should file Supplemental Reports as necessary, including those supplementing prior years' Reports.

The terms "barrel", "breakout tank", "carbon dioxide", "flammable product", "gathering line", "hazardous liquid", "highly volatile liquid (HVL)", "intrastate pipeline", "interstate pipeline", "low stress pipeline", "maximum operating pressure", "offshore", "operator", "Outer Continental Shelf (OCS)", "petroleum", "petroleum product", "pipe or line pipe", "pipeline or pipeline system", "pipeline facility", "rural area", "specified minimum yield strength (SMYS)", "stress level", "toxic product", and "Unusually Sensitive Area (USA)" are defined in §195.2.

If you need copies of the Form PHMSA F 7000-1.1 and/or instructions they can be found on the Pipeline Safety Community main page, http://phmsa.dot.gov/pipeline, by clicking Data and Statistics and then selecting the Forms hyperlink. If you have questions about this Report or these instructions, please call PHMSA's Information Resources Manager at 202-366-8075.

## ONLINE REPORTING REQUIREMENTS

The following two requirements must be fulfilled prior to submitting data online:

1. You must have an Office of Pipeline Safety (OPS) provided Operator Identification Number (OPID) and Personal Identification Number (PIN)/password. If you do not have one, please complete and submit the form located on the OPS Online Data Entry and Operator Registration System New Operator Registration web site at http://opsweb.phmsa.dot.gov/cfdocs/opsapps/pipes/new_operator.cfm to obtain one.

2. You must have a Username and Password obtained by registering through the PHMSA Portal. If you have an OPS OPID and PIN/password, you may obtain a Username and Password through the PHMSA Portal.

Important: Each operator without an OPID is to plan accordingly and allow for several weeks prior to the due date of the Report to obtain their OPID from PHMSA.

## REPORTING METHOD

Annual Reports must be submitted online unless an alternate method is approved (see Alternate Reporting Methods below). Use the following procedure:

1. Navigate to the Pipeline Safety Community main page, http://www.phmsa.dot.gov/pipeline, click the **ONLINE DATA ENTRY** link listed.

2. Click on the Annual Hazardous Liquid or Carbon Dioxide Pipeline Systems Report link

3. Enter Operator Identification Number (OPID) and PIN. [If an operator does not have an OPID or a PIN, the **ONLINE DATA ENTRY** page includes directions on how to obtain one.]

4. Click A**dd** to begin data entry for a new calendar year's Report. [For Supplemental Reports, click on the Report ID and select **Modify** to make corrections or add new information.]

5. To save intermediate work without formally submitting it to PHMSA, click **Save**.

6. Click **Submit** when you have completed the Report (for either an Initial Report or a Supplemental Report) and are ready to initiate formal submission of your Report to PHMSA.

7. A confirmation page will appear for you to print and save for your records.

**Alternate Reporting Methods**

Operators for whom electronic reporting imposes an undue burden and hardship may submit a written request for an alternate reporting method. Operators must follow the requirements in §195.58(d) to request an alternate reporting method and must comply with any conditions imposed as part of PHMSA's approval of an alternate reporting method.

## SPECIFIC INSTRUCTIONS

Make an entry in each block for which data is available. Estimate data only if necessary. Avoid entering any data as **UNKNOWN or 0 (zero)** except where zero is appropriate to indicate that there were no instances or amounts of the attribute being reported.

Do not report miles of pipe, pipe segments, or pipeline in feet. When reporting mileages that are less than 1 mile or when reporting portions of a mile, convert feet into a decimal notation (e.g. 2,640 feet = .5 miles) and report mileage using decimals rounded to the nearest tenth of a mile. Operators may round all mileages that are greater than 1 mile to the nearest mile. Do not use fractions.

Enter the Calendar Year for which the Report is being filed, bearing in mind that reporting requirements are for the preceding calendar year (i.e., for the June 15, 2011 deadline, the Report should provide information for assets as they existed at the end of the 2010 calendar year).

Select **Initial Report** if this is the original filing for the calendar year. Select **Supplemental Report** if this is a follow-up to a previously filed Report to amend or correct information for that calendar year. On Supplemental Reports, enter all information requested in Parts A and N, and only the new or revised information for the other Parts of the Report, completing Part O as required.

Report miles of pipe, pipe segments, or pipeline in the system at the end of the reporting year, including any additions or deletions to the system occurring during that year. Report other data for the duration of the calendar year as appropriate. Adhere to definitions in 49 CFR 195 when reporting mileage and other data.

**For a given OPID, a separate Annual Report is to be completed for each Commodity Group within that OPID. The separate Annual Report is to cover all pipelines and/or pipeline facilities – both INTERstate and INTRAstate – included within that OPID that serve to transport that Commodity Group. As an example, if an operator uses a single OPID and has one set of facilities and/or pipelines that transport crude oil and another that transports refined products, this operator is to file two Annual Reports – one Annual Report covering all the facilities and/or pipelines that transport crude oil and another Annual Report covering all the facilities and/or pipelines that transport refined products. If another operator utilizes two OPIDs with both crude oil and refined products facilities and/or pipelines within each OPID, that operator must file four separate Annual Reports.**

**Parts A – E are to be completed once for each Annual Report, namely once for each Commodity Group within an OPID, covering ALL of the pipelines and/or facilities (both Interstate and Intrastate) and combining all states in which those assets exist. Separate reporting by state is not required for these Parts. Parts F – M, however, are to be reported separately for Interstate and for Intrastate facilities, or by state, or both depending on the instructions pertaining to each Part.**

## PART A - OPERATOR INFORMATION

Complete all 8 sections of Part A before continuing to the next Part.

**1. Operator's 5 digit Identification Number (OPID)**

All operators that meet the definition of an "operator" under §195.2 must have a PHMSA-assigned Operator Identification Number (also known as an OPID). If the person completing the Report does not know the OPID for the system being reported, this information may be requested from PHMSA's Information Resources Manager at 202-366-8075. (See instructions on the ONLINE DATA ENTRY page as described above.)

**2. Name of Company or Establishment**

This is the company name used when registering for an OPID and PIN in the Online Data Entry System. When completing the Report online, the Name of Operator is automatically filled in based on the OPID entered in Part A, Question 1. If the name that appears does not coincide with the OPID, contact PHMSA's Information Resources Manager.

If the company corresponding to the OPID is a subsidiary, enter the name of the parent company.

**3. Individual where additional information may be obtained**

Enter the name, title, email address, and telephone number of the individual who should be contacted if additional information regarding this Report submission is needed.

**4. Headquarters address**

Enter the address and phone number of the operator's corporate headquarters.

**5. This Report pertains to the following Commodity Group**

It is a PHMSA requirement (§195.49) that operators submit separate Reports for each Commodity Group within a particular OPID. It should be noted that these Commodity Groups, though similar to the Commodity Groups used when reporting accidents to PHMSA, are not precisely the same when it comes to the reporting of pipelines that transport fuel grade ethanol and ethanol blends. Whereas fuel grade ethanol and ethanol blends are grouped in the same category for accident reporting purposes, pipelines that transport fuel grade ethanol have their own Commodity Group for the purposes of Annual Reporting. Pipelines that transport ethanol in a blended state should be reported as Refined and/or Petroleum Product (non-HVL) in an operator's Annual Report.

**File a separate Annual Report for each** of the following **Commodity Groups** (as further defined in §195.2):

**Crude Oil** - unrefined oil consisting mainly of hydrocarbons.

**Refined and/or Petroleum Product (non-HVL)** – flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds. Examples include motor gasoline, diesel fuel, fuel oil, aviation gasoline, jet fuel, kerosene, acetone, benzene, MTBE, naphtha, or other non-HVL petroleum products. For the sake of this Report, "petroleum product" is meant to be synonymous with "refined product".

**Highly Volatile Liquids (HVLs)** – a hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 276 kPa at 37.8º C (100º F). Examples include ethane, ethylene, propane, propylene, butylene, and anhydrous ammonia ($NH_3$).

**Carbon Dioxide ($CO_2$) –** a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state.

**Fuel Grade Ethanol** – a clear, colorless, flammable oxygenated hydrocarbon. Ethanol is typically produced chemically from ethylene, or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. This Commodity Group is to be selected only if the pipeline and/or pipeline facility is used predominantly to transport ethanol which has NOT been blended with petroleum products. This commodity is sometimes also known as "neat" ethanol. Pipelines that transport ethanol in a blended state should be reported as Refined and/or Petroleum Product (non-HVL).

Note: When a single pipeline or facility serves to transport two or more of the above Commodity Groups, that pipeline or facility should be reported only once, reporting within the Commodity Group for the commodity that is transported most predominantly during the year being reported.

**6. Integrity Management Program**

Indicate here whether any portion(s) of the pipelines and/or pipeline facilities for this Commodity Group covered under this OPID are subject to the integrity management (IM) requirements of §195.452.

Pipelines and/or pipeline facilities that include segments that could affect high consequence areas (HCAs) are required to have an IM Program in accordance with §195.452. For the purposes of this question and, more generally, this Report, do not consider pipelines or portions of pipelines that could otherwise not affect an HCA but which are included in an IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.). Select the box indicating that portions of *SOME or ALL* of the pipelines and/or pipeline facilities for this Commodity Group covered under this OPID are included in an IM Program as required by §195.452, and complete other Parts of this Report in accordance with Part A, Question 8.

If *NO PORTIONS* of the pipelines and/or pipeline facilities for this Commodity Group covered under this OPID are included in an IM Program as required by §195.452, select the box indicating such. In this case, Parts B, F, G, L, and O need not be completed.

**7. Interstate and/or Intrastate pipeline**

Pipeline assets included within a particular Commodity Group under a single OPID may be either interstate, intrastate, or both. Select the appropriate box or boxes to indicate whether the pipelines and/or pipeline facilities for the OPID and Commodity Group are interstate or intrastate or both. List the two-letter state abbreviation for each state in which reported interstate and/or intrastate assets are located.

The terms Interstate and Intrastate pipeline are defined in §195.2. Appendix A to 49 CFR 195 contains PHMSA's Statement of Policy and Interpretation on the delineation between interstate and intrastate pipelines, and provides additional guidance.

**8. Does this Report represent a change from last year's final reported information for one or more of the following Parts?**

Select "This Report is for calendar year 2010 reporting or is a first-time Report…" only for the reporting of calendar year 2010 information, including any supplements to that information, or if this is a first-time filing of an Annual Report for these facilities. Because this revision of the Annual Report will be used for the first time to report information for calendar year 2010, some of the "Parts" of this Report referred to in this question are new and, therefore, no comparable information will have been reported for the prior year. For calendar year 2010 only, respond to this question by selecting the box "This Report is for calendar year 2010 reporting or is a first-time Report…", and then complete all remaining Parts of the Report as applicable. Similarly, if no Annual Report has been previously filed for this operator, OPID, Commodity Group, or pipelines and/or pipeline facilities, or for other reasons, select the box "This Report is for calendar year 2010 reporting or is a first-time Report…", and then complete all remaining Parts of the Report as applicable.

For calendar year submissions beyond 2010, an option has been created to allow the operator to provide information for relevant Parts when certain portions of the information have not changed.

Select "No" if there are no changes in the information reported for the current reporting year compared against the prior calendar year for Parts B, D, E, H, I, J, K, L, or M for the Commodity Group reported.

It should be noted that PHMSA expects that the data describing volume transported (Part C) and integrity management activity (Parts F and G) will change each year. Therefore, Part C, describing volume transported, must be completed every year. Additionally, those Parts of this Report related to integrity management activity (Parts F, G and O) must be completed every year by every operator with portions of pipelines and/or pipeline facilities subject to PHMSA's IM regulations as indicated in Part A, Question 6.

When there are changes in the information reported for the current reporting year compared against the prior calendar year, these changes can occur for one of the two following reasons:

1) New information or new calculations may have changed the understanding of pipeline and/or pipeline facility data, leading to differences in some data elements reported on the Annual Report in the previous year's Report, even though the physical pipeline(s) and/or pipeline facility(ies) themselves have not changed; or,

2) The pipeline(s) and/or pipeline facility(ies) may have changed – either physically or operationally.

Select one or both of the two "Yes" boxes if reported system information has changed. If the change is due to a change in the pipelines and/or pipeline facilities and/or operations (number 2 above), select the appropriate box or boxes to indicate the nature of the change(s). If "Other" is selected, provide a brief description of the change.

- Merger/acquisition involves a change in ownership or operating responsibility that would likely result in increases or other changes in the reported miles of pipeline in most Parts of the Report.

- Divestiture involves a change in ownership or operating responsibility that would likely result in decreases or other changes in the reported miles of pipeline.

- New construction or new installation that would likely result in increases or other changes in the reported miles of pipeline, including rerouting of pipelines.

- Conversion of service, change in commodity transported, or change in MOP (maximum operating pressure).

    - Conversion to service means conversion to transportation of hazardous liquids under §195.5 that would likely result in increases or other changes in the reported miles of pipeline. (This is selected if a

pipeline that was previously used to transport a commodity or material that was not covered under 49 CFR 195, such as water, is being converted to move a commodity that is covered under 49 CFR 195, such as a crude oil line.)

- Change in commodity transported means a change in the commodity predominately transported and thus in the Commodity Group reported in Part A, Question 5. (This is selected if the previous commodity moved in a pipeline covered under 49 CFR 195 is changed to a different commodity moved under 49 CFR 195, for example a refined products line being changed to a crude oil line.)

- Change in MOP (maximum operating pressure) could result in changes to the mileage of pipeline operating in different categories of hoop stress (i.e., percent SMYS (Specified Minimum Yield Strength)) as reported in Part J.

- "Abandoned," as defined in § 195.2, means permanently removed from service. All pipeline mileage not permanently removed from service should be reported, including pipelines and/or pipeline facilities considered to be idled.

- Change in various aspects of an operator's IM Program may result in changes to information reported in Parts B, F, and/or G.

- Change in an operator's OPID number – or changes in pipelines and/or pipeline facilities covered by a particular OPID number – may result in changes throughout the Annual Report.

**For the designated Commodity Group, complete Parts B, C, D, and E one time for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate – included within this OPID. Separate reporting by state is not required for these Parts. Data reported should represent the system in total, including all states in which system assets are located.**

## PART B - MILES OF PIPE BY LOCATION

Report in Part B the total miles of Onshore and Offshore pipe that could affect High Consequence Areas (HCAs) and are thus in the IM Program. Operators should NOT double-count mileage for a single segment of pipeline that may be able to affect HCAs of multiple types (e.g., an Other Population Area as well as a Drinking Water USA). Also, do not include miles of pipeline that could not affect an HCA but which are included in the IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.). This Part should be left blank if no portions of the pipelines and/or pipeline facilities covered by this OPID are in an IM Program, as indicated in Part A, Question 6.

## PART C – VOLUME TRANSPORTED IN BARREL-MILES

Barrel-miles means the total of the number of barrels transported multiplied by the distance in miles the specific barrels were moved. Report the volume of all commodities transported during the calendar year for this Commodity Group. Include the annual total volume transported in barrel-miles for all states and for all pipelines and/or pipeline facilities – both INTERstate and INTRAstate – included within this OPID and for this Commodity Group. Volumes of any Commodity Group transported in addition to the Commodity Group predominately transported through these pipelines and/or pipeline facilities should also be reported in Part C within the proper row. Example: If 2,000,000 barrels of crude oil were moved in one 35-mile onshore pipeline from end to end and 80,000,000 barrels of crude oil were moved in a second 1,000-mile onshore pipeline from end to end, both occurring in a given reporting year, then the total volume transported in barrel-miles for the Crude Oil Commodity Group for Onshore is equal to (2,000,000 x 35) + (80,000,000 x 1,000) = 70,000,000 + 80,000,000,000 = 80,070,000,000 Onshore Crude Oil Barrel-Miles. If, additionally, 500,000 barrels of an HVL were moved in the same 35-mile onshore pipeline from end to end, then 17,500,000 barrel-miles (500,000 x 35) should also be included in Part C for the Crude Oil Commodity Group under the "HVL" row and "Onshore" column in the table.

## PART D - MILES OF STEEL PIPE BY CORROSION PROTECTION

For steel pipe only, report the total miles of Onshore and Offshore pipe that is cathodically protected and cathodically unprotected subdivided, in each case, into the amount that is bare and the amount that is coated pipe. **COATED** means steel pipe coated with an effective hot or cold applied dielectric coating or wrapper. Enter zero (0) in any cell for which the pipeline system includes no mileage. Do not leave any cells blank.

## PART E – MILES OF ELECTRIC RESISTANCE WELDED (ERW) PIPE BY WELD TYPE AND DECADE

Report here only pipe that was manufactured using an electric resistance welded (ERW) process. Report separately, each by decade installed, the miles of installed pipe manufactured using a high-frequency ERW process and that manufactured with a low-frequency or DC ERW process.

"High Frequency" means the ERW pipe was manufactured using a high frequency ERW process. High frequency ERW pipe is pipe that was manufactured using a high frequency electrical current, usually about 450 thousand Hertz (kHz) to provide heat for fusion of the weld seam. Most pipe manufactured using this process has been manufactured since the late 1960s.

"Low Frequency" means the ERW pipe was manufactured using a low frequency ERW process. Low frequency ERW pipe is pipe that was manufactured using a low frequency, usually about 250 Hertz (Hz) alternating electrical current to provide heat for fusion of the weld seam. Most pipe manufactured using this process was manufactured prior to 1970.

Flash welded pipe (EFW) is NOT a type of ERW pipe and should NOT be included in the reported numbers for this Part E.

"DC" means direct current.

Make an entry in each block. PHMSA recognizes that some companies may have pipe for which installation records may not exist. If records do not exist, enter estimates of the totals of such mileage in the "Pre-40 or Unknown" section of Part E. Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any blocks blank.

**For the designated Commodity Group, complete Parts F and G one time for all INTERstate pipelines and/or pipeline facilities included within this OPID and multiple times as needed for the designated Commodity Group for each State in which INTRAstate pipelines and/or pipeline facilities included within this OPID exist.**

**For example: Consider a set of crude oil pipeline systems that includes INTERstate pipeline facilities in seven states and INTRAstate pipeline facilities in three states. Parts F and G should be completed four times for this set of crude oil pipeline systems – once for all INTERstate assets (combined) and once for the INTRAstate assets in each of the three states in which INTRAstate assets are located (separately).**

**Each time Parts F and G are completed, indicate whether the data reported is for INTERstate or INTRAstate pipelines and/or pipeline facilities. If INTRAstate, enter in the space provided the two-letter postal abbreviation for the state.**

## PART F - INTEGRITY INSPECTIONS CONDUCTED AND ACTIONS TAKEN BASED ON INSPECTION

Report all integrity assessments (inspections) required by PHMSA's IM regulations which were conducted and actions which were taken during the calendar year based on inspection results. Include all inspections conducted in the reporting period calendar year including baseline assessments and re-assessments. Do not consider pipelines or portions of pipelines that could otherwise not affect an HCA but which are included in an IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.). Part F is subdivided into six (6) sections.

### Section 1 - Mileage inspected in calendar year using the following In-Line Inspection (ILI) tools.

Report the mileage inspected using each of the listed tool types. Include total miles inspected, not just the mileage that could affect a high consequence area. Where multiple ILI tools are used (e.g., a metal loss tool and a deformation tool), report the mileage in both categories. Where a combination tool is used (i.e., a single tool with multiple capabilities), report the mileage separately in each category included as part of the combination. Thus, the total mileage inspected during the calendar year (the sum of

the mileage reported for individual tools) may be greater than the actual number of physical pipeline miles on which ILI inspections were run.

Enter zero (0) for any tool which was not used for IM assessments during the year. Leave no rows blank.

**Section 2 - Actions taken in calendar year based on In-Line Inspections.**

Include all actions taken during the calendar year that resulted from information obtained during an ILI inspection. This should include actions taken as a result of information developed during ILI inspections conducted during the calendar year PLUS actions taken as a result of ILI inspections conducted during prior years and for which all required actions were not completed during the year of the inspection. Do not include actions which are anticipated based on review of ILI results but which did not actually occur during the reporting year.

Report in items a. and b. the total number of anomalies excavated and repaired based on the operator's repair criteria even if those criteria are different from (i.e., require repair of damage more or less significant) than the repair criteria in IM regulations applicable to anomalies in pipeline segments that could affect HCA. (The operator's criteria for anomalies in segments that could affect an HCA must be at least as conservative as those required by the regulations).

Report in a. the total number of anomalies excavated, recognizing that multiple anomalies may be exposed in a single excavation.

Report in b. only those anomalies actually repaired, not those for which other mitigative actions (not repair) were undertaken.

Report in c. only the anomalies in pipeline segments that could affect an HCA that were repaired because they met one of the three repair criteria in the IM regulations. (The total of repairs reported in item c. should not exceed the total number of repairs reported in item b.)

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank.

**Section 3 – Mileage inspected and actions taken in calendar year based on Pressure Testing.**

Report in a. the total miles inspected by pressure testing, including both mileage that could affect an HCA and mileage that could not affect an HCA.

Report in b. the total number of test failures (ruptures and leaks) repaired on all mileage tested during the year.

Report in c. the ruptures and in d. the leaks repaired ONLY in segments that could affect an HCA.

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank. Enter zero (0) in all rows of section 3 if no IM assessments were conducted by pressure test during the year.

**Section 4 - Mileage inspected and actions taken in calendar year based on ECDA (External Corrosion Direct Assessment)**

Include all actions taken during the calendar year that resulted from information obtained during an ECDA inspection. This should include actions taken as a result of information developed during ECDA inspections conducted during the calendar year PLUS actions taken as a result of ECDA inspections conducted during prior years and for which all required actions were not completed during the year of the inspection. Do not include actions which are anticipated based on ECDA inspection results but which did not actually occur during the reporting year.

Report in b. the total number of anomalies excavated and repaired based on the operator's repair criteria even if those criteria are different from (i.e., require repair of damage more or less significant) than the repair criteria in IM regulations applicable to anomalies in pipeline segments that could affect an HCA. (The operator's criteria for anomalies in segments that could affect an HCA must be at least as conservative as those required by the regulations).

Report in c. the number of anomalies in pipeline segments that could affect an HCA that were repaired because when excavated and examined they met one of the three repair criteria in the IM regulations.

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank.

**Section 5 – Mileage inspected and actions taken in calendar year based on Other Inspection Techniques**

IM regulations allow operators to use other assessment techniques provided that they notify PHMSA (or states exercising regulatory jurisdiction) in advance. Report here the mileage inspected and actions taken as a result of inspections conducted using any technique other than those covered in Sections 1-4 of Part F.

As for the other techniques, include all actions taken during the calendar year that resulted from information obtained during an inspection using another technique. This should include actions taken as a result of information developed as part of inspections conducted during the calendar year PLUS actions taken as a result of inspections conducted during prior years and for which all required actions were not completed during the year of the inspection. Do not include actions which are anticipated based on inspection results but which did not actually occur during the reporting year.

Report only those anomalies actually repaired, not those for which other mitigative actions (not repair) were undertaken.

Enter a value in each row, using zero (0) as appropriate. Leave no rows blank.

**Section 6 - Total Mileage Inspected (all Methods) and Actions Taken.**

These entries will be calculated automatically based on data entered in Sections 1-5. For operators completing a paper form as a result of PHMSA approval to use alternate reporting measures (see above), report here the total mileage inspected and actions taken as the sum of the indicated elements from other sections.

## PART G – MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS COMPLETED IN CALENDAR YEAR (segment miles that could affect HCAs ONLY)

Report the number of miles of pipeline that could affect an HCA (as reported in Part B) that were assessed during the calendar year pursuant to §195.452. Report separately the number of miles inspected for baseline assessments (e.g., initial baseline assessments and new baseline assessments, including those which occur due to new pipelines or facilities, new or newly identified HCAs, new spill flow paths, new spill volume calculations, low-stress pipe for which the baseline assessment deadline has not yet passed, etc.) and miles for which a reassessment was conducted. Do not include pipelines or portions of pipelines that could otherwise not affect an HCA but which are included in an IM Program as a result of other PHMSA directives (such as Corrective Action Orders, Compliance Orders, Special Permits, etc.).

Report only assessments that were completed during the calendar year. These "completed assessments" are defined consistently with FAQ 4.13 http://primis.phmsa.dot.gov/iim/faqs.htm. ***The date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed***, not including repair activities. That is, when a hydrostatic test is completed, when the last in-line inspection tool run of a scheduled series of tool runs is performed, when the last direct examination associated with external corrosion direct assessment is made, or the date on which "other technology" for which an operator has provided timely notification is conducted.

Operators should report in Part G the total number of miles actually assessed. This differs from Part F where operators report the number of miles inspected by individual inspection methods where some mileage may be reported multiple times. Operators should note that the mileages reported as completed assessments in Part G should be a subset of the total miles of onshore/offshore pipe that could affect High Consequence Areas reported in Parts B and L. Operators should validate the total completed and scheduled assessment mileage in their Assessment Plans with the mileage reported here. The comparison of these two numbers will highlight any discrepancies resulting from new HCA segments being added or deleted, acquired or sold, or idled[1] or converted, and which need to be properly reflected in this Report.

[1] While the regulations do not recognize an intermediate state between operational and abandoned (see instructions for Part A, Question 8 above), PHMSA has acknowledged that operators sometimes maintain some of their pipe in an idle status in which conducting IM assessments is impractical. This consideration of "idle" pipe is discussed in FAQ 2.3 on the PHMSA IM website (http://primis.phmsa.dot.gov/iim/faqs.htm).

**For the designated Commodity Group, complete Parts H, I, J, K, L, and M covering INTERstate pipelines and/or pipeline facilities separately for each State in which INTERstate systems exist within this OPID and again covering INTRAstate pipelines and/or pipeline facilities separately for each State in which INTRAstate systems exist within this OPID.**

**For example: Consider a set of crude oil pipeline systems that includes INTERstate pipeline facilities in seven states and INTRAstate pipeline facilities in three states. Parts H, I, J, K, L, and M should be completed ten times for this set of crude oil pipeline systems – seven times for INTERstate assets (once for each of the seven states in which INTERstate assets are located) and once for the INTRAstate assets in each of the three states in which INTRAstate assets are located.**

**Each time the remaining Parts are completed, indicate whether the data reported is for INTERstate or INTRAstate pipelines and/or pipeline facilities, and enter in the space provided the two-letter postal abbreviation for the state.**

## PART H – MILES OF PIPE BY NOMINAL PIPE SIZE (NPS)

Report the miles of pipe by Nominal Pipe Size (NPS) and location for both onshore and offshore locations. Enter the appropriate mileage in the corresponding nominal size blocks.

Pipe sizes which do not correspond to NPS measurements should be included in the "Other Pipe Sizes Not Listed" columns. Include both the pipe size and the corresponding mileage.

Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any blocks blank.

## PART I – MILES OF PIPE BY DECADE INSTALLED

Report the miles of pipe by decade installed. Make an entry in each block including zero (0) when appropriate. Some companies may have pipe for which installation records may not exist. When the decade of construction is unknown, enter estimates of the totals of such mileage in the "Pre-20 or Unknown" section of Part I.

The sum total of pipeline mileage reported in Part I should match the totals reported in Parts H and J.

## PART J – MILES OF PIPE BY SPECIFIED MINIMUM YIELD STRENGTH

Report the total miles of steel pipe by hoop stress (as percent of SMYS) and pipe material type (steel or non-steel) for pipe onshore (in non-rural and rural areas where indicated) and offshore.

Report the total miles of non-steel pipe operating above 125 psig and at or below 125 psig,

differentiated for location as for steel pipe.

Report data only for pipelines regulated by PHMSA (and their certified State agencies) and not those which are regulated by other federal or state authorities, including those rural, low stress pipeline segments subject only to Subpart B of 49 CFR 195.

Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any blocks blank.

## PART K – MILES OF REGULATED GATHERING LINES

This Part only applies to the Commodity Group "crude oil" and to those portions of gathering lines that are regulated by PHMSA. Report the total mileage of these lines only.

Gathering lines are defined in §195.2 as "A pipeline 219.1mm (8-5/8 inch) or less nominal outside diameter that transports petroleum from a production facility."

Regulated rural gathering lines are defined in §195.11(a) and should be reported in this Part.

Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any blocks blank.

## PART L – TOTAL SEGMENT MILES THAT COULD AFFECT HCAs

**By Type of HCA.** Report the miles of pipeline that the operator has determined could affect an HCA of each designated type. Operators should note that a single segment of pipeline may be able to affect HCAs of multiple types (e.g., an Other Population Area as well as a Drinking Water USA). Accordingly, the total of the miles reported in these columns may add to more than the total mileage that could affect an HCA reported in Part B.

**Not By Type.** Report the total miles of pipeline that the operator has determined could affect an HCA. For this number, Operators should NOT double-count mileage for a single segment of pipeline that may be able to affect HCAs of multiple types (e.g., an Other Population Area as well as a Drinking Water USA). Accordingly, the total of the miles reported in this column, when added for each State, should equal the total mileage that could affect an HCA reported in Part B.

Enter zero (0) in any block for which the pipeline system includes no mileage. Do not leave any blocks blank.

## PART M – BREAKOUT TANKS

List the number of tanks by capacity and by Commodity Group, including any Commodity Groups which are not the predominantly transported Commodity Group within this Report. The Commodity Groups listed here in Part M should match those listed in Part C. Operators are required to submit all breakout tank information in their Annual Report. The operator can also submit their breakout tank information to NPMS, but breakout tanks must always be reported in their Annual Report.

**For the designated Commodity Group, complete Part N one time for all of the pipelines and/or pipeline facilities included within this OPID. Complete Part O one time for all the pipelines and/or pipeline facilities covered under this Commodity Group and OPID if any portion(s) of the pipelines and/or pipeline facilities are included in an IM Program subject to §195.452 as indicated in Part A, Question 6.**

## PART N – PREPARER SIGNATURE

The Preparer is the person who compiled the information and prepared the responses to the Report. Enter the Preparer's name and title, and e-mail address if the Preparer has one, as well as the phone and fax numbers used by the Preparer.

## PART O – CERTIFYING SIGNATURE

**CERTIFYING SIGNATURE** must be a senior executive officer of the operator. The Pipeline Inspection, Protection, Enforcement and Safety Act (signed in December 2006) requires pipeline operators to have a senior executive officer of the company sign and certify annual pipeline Integrity Management Program (IMP) performance reports (Parts B, F, G, and L of this Report). By this signature, the senior executive officer is certifying that he or she has (1) reviewed the Report and (2) to the best of his or her knowledge, believes the Report is true and complete.

**Senior Executive Officer** is the person who is certifying the information on Parts B, F, G, and L as required by 49 U.S.C. 60109(f).

The name and title of the senior executive officer certifying the Report should be entered in the appropriate blanks on this section of the Report. The name of the senior executive officer certifying the Report should also be entered in the signature block on the Report. Operators should keep in mind that entering the senior executive officer's name onto the electronic Report is equivalent to a paper submission and has the same legal authenticity and requirements.

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.

OMB NO: 2137-0047

EXPIRATION DATE: 01/31/2013

U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

# ACCIDENT REPORT – HAZARDOUS LIQUID PIPELINE SYSTEMS

Report Date _____

No. _____
(DOT Use Only)

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0047. Public reporting for this collection of information is estimated to be approximately 10 hours per response (5 hours for a small release), including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

**INSTRUCTIONS**

***Important:*** *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline. Note: Certain low consequence accidents only require the information indicated in the shaded fields.*

**PART A – KEY REPORT INFORMATION**

*Report Type: *(select all that apply)* ☐ Original ☐ Supplemental ☐ Final

*1. Operator's OPS-issued Operator Identification Number (OPID): /___/___/___/___/___/___/

*2. Name of Operator: _____

*3. Address of Operator:

*3.a _____
(Street Address)

*3.b _____
(City)

*3.c State: /___/___/

*3.d Zip Code: /___/___/___/___/___/ - /___/___/___/___/

*4. Local time *(24-hr clock)* and date of the Accident:

/___/___/___/___/ Hour  /___/___/ Month  /___/___/ Day  /___/___/ Year

*5. Location of Accident:

Latitude: /___/___/ . /___/___/___/___/___/

Longitude: - /___/___/___/ . /___/___/___/___/___/

6. National Response Center Report Number (if applicable):

/___/___/___/___/___/___/___/

7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):

/___/___/___/___/ Hour  /___/___/ Month  /___/___/ Day  /___/___/ Year

*8. Commodity released: *(select only one, based on predominant volume released)*

☐ Crude Oil

☐ Refined and/or Petroleum Product (non-HVL) which is a Liquid at Ambient Conditions

- ○ Gasoline (non-Ethanol)
- ○ Diesel, Fuel Oil, Kerosene, Jet Fuel
- ○ Mixture of Refined Products (transmix or other mixture)
- ○ Other ⇨ Name: _____

☐ HVL or Other Flammable or Toxic Fluid which is a Gas at Ambient Conditions

- ○ Anhydrous Ammonia
- ○ LPG (Liquefied Petroleum Gas) / NGL (Natural Gas Liquid)
- ○ Other HVL ⇨ Name: _____

☐ $CO_2$ (Carbon Dioxide)

☐ Biofuel / Alternative Fuel (including ethanol blends)

- ○ Fuel Grade Ethanol
- ○ Ethanol Blend ⇨ % Ethanol: /___/___/
- ○ Biodiesel ⇨ Blend (e.g. B2, B20, B100): B/___/___/___/
- ○ Other ⇨ Name: _____

*9. Estimated volume of commodity released unintentionally: /___/___/___/,/___/___/___/./___/___/ Barrels

10. Estimated volume of intentional and/or controlled release/blowdown: /___/___/___/,/___/___/___/./___/___/ Barrels

*11. Estimated volume of commodity recovered: /___/___/___/,/___/___/___/./___/___/ Barrels

*12. Were there fatalities? ○ Yes ○ No

If Yes, specify the number in each category:

*12.a Operator employees /___/___/___/___/

*12.b Contractor employees working for the Operator /___/___/___/___/

*12.c Non-Operator emergency responders /___/___/___/___/

*12.d Workers working on the right-of-way, but NOT associated with this Operator /___/___/___/___/

*12.e General public /___/___/___/___/

12.f Total fatalities (sum of above) /___/___/___/___/

*13. Were there injuries requiring inpatient hospitalization? ○ Yes ○ No

If Yes, specify the number in each category:

*13.a Operator employees /___/___/___/___/

*13.b Contractor employees working for the Operator /___/___/___/___/

*13.c Non-Operator emergency responders /___/___/___/___/

*13.d Workers working on the right-of-way, but NOT associated with this Operator /___/___/___/___/

*13.e General public /___/___/___/___/

13.f Total injuries (sum of above) /___/___/___/___/

14. Was the pipeline/facility shut down due to the Accident?

○ Yes ○ No ⇨ Explain: _____

If Yes, complete Questions 14.a and 14.b: *(use local time, 24-hr clock)*

14.a Local time and date of shutdown /___/___/___/___/ (Hour) /___/___/ (Month) /___/___/ (Day) /___/___/ (Year)

14.b Local time pipeline/facility restarted /___/___/___/___/ (Hour) /___/___/ (Month) /___/___/ (Day) /___/___/ (Year) ○ Still shut down* *(*Supplemental Report required)*

*15. Did the commodity ignite? ○ Yes ○ No

*16. Did the commodity explode? ○ Yes ○ No

17. Number of general public evacuated: /___/___/___/,/___/___/___/

18. Time sequence: *(use local time, 24-hour clock)*

18.a Local time Operator identified Accident /___/___/___/___/ (Hour) /___/___/ (Month) /___/___/ (Day) /___/___/ (Year)

18.b Local time Operator resources arrived on site /___/___/___/___/ (Hour) /___/___/ (Month) /___/___/ (Day) /___/___/ (Year)

**PART B – ADDITIONAL LOCATION INFORMATION**

*1. Was the origin of the Accident onshore?
○ Yes *(Complete Questions 2-12)* ○ No *(Complete Questions 13-15)*

If **Onshore**:

*2. State: /___/___/

*3. Zip Code: /___/___/___/___/___/ - /___/___/___/___/

4._____ 5_____
City County or Parish

6. Operator-designated location: *(select only one)*
☐ Milepost/Valve Station *(specify in shaded area below)*
☐ Survey Station No. *(specify in shaded area below)*

/___/___/___/___/___/___/___/___/___/___/___/___/___/___/___/

7. Pipeline/Facility name: _____

8. Segment name/ID: _____

*9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)? ○ Yes ○ No

*10. Location of Accident: *(select only one)*
☐ Totally contained on Operator-controlled property
☐ Originated on Operator-controlled property, but then flowed or migrated off the property
☐ Pipeline right-of-way

*11. Area of Accident (as found): *(select only one)*
☐ Tank, including attached appurtenances
☐ Underground ⇨ Specify: ○ Under soil
○ Under a building ○ Under pavement
○ Exposed due to excavation
○ In underground enclosed space (e.g., vault)
○ Other _____
Depth-of-Cover (in): /___/,/___/___/___/
☐ Aboveground ⇨ Specify:
○ Typical aboveground facility piping or appurtenance
○ Overhead crossing
○ In or spanning an open ditch
○ Inside a building ○ Inside other enclosed space
○ Other _____
☐ Transition Area ⇨ Specify: ○ Soil/air interface ○ Wall sleeve ○ Pipe support or other close contact area
○ Other _____

*12. Did Accident occur in a crossing?: ○ Yes ○ No
If Yes, specify type below:
☐ Bridge crossing ⇨ Specify: ○ Cased ○ Uncased
☐ Railroad crossing ⇨ *(select all that apply)*
○ Cased ○ Uncased ○ Bored/drilled
☐ Road crossing ⇨ *(select all that apply)*
○ Cased ○ Uncased ○ Bored/drilled
☐ Water crossing
⇨ Specify: ○ Cased ○ Uncased
Name of body of water, if commonly known:
_____
Approx. water depth (ft) at the point of the Accident:
/___/,/___/___/___/
*(select only one of the following)*
○ Shoreline/Bank crossing
○ Below water, pipe in bored/drilled crossing
○ Below water, pipe buried below bottom (NOT in bored/drilled crossing)
○ Below water, pipe on or above bottom

If **Offshore**:

*13. Approximate water depth (ft.) at the point of the Accident:
/___/___/,/___/___/___/

*14. Origin of Accident:
☐ In State waters
⇨ Specify: State: /___/___/
Area: _____
Block/Tract #: /___/___/___/___/
Nearest County/Parish: _____
☐ On the Outer Continental Shelf (OCS)
⇨ Specify: Area: _____
Block #: /___/___/___/___/

*15. Area of Accident: *(select only one)*
☐ Shoreline/Bank crossing or shore approach
☐ Below water, pipe buried or jetted below seabed
☐ Below water, pipe on or above seabed
☐ Splash Zone of riser
☐ Portion of riser outside of Splash Zone, including riser bend
☐ Platform

**PART C – ADDITIONAL FACILITY INFORMATION**

*1. Is the pipeline or facility:
- ☐ Interstate
- ☐ Intrastate

*2. Part of system involved in Accident: *(select only one)*
- ☐ Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances ⇨ ○ Atmospheric or Low Pressure ○ Pressurized
- ☐ Onshore Terminal/Tank Farm Equipment and Piping
- ☐ Onshore Equipment and Piping Associated with Belowground Storage
- ☐ Onshore Pump/Meter Station Equipment and Piping
- ☐ Onshore Pipeline, Including Valve Sites
- ☐ Offshore Platform/Deepwater Port, Including Platform-mounted Equipment and Piping
- ☐ Offshore Pipeline, Including Riser and Riser Bend

*3. Item involved in Accident: *(select only one)*

☐ Pipe ⇨ Specify: ○ Pipe Body ○ Pipe Seam

3.a Nominal diameter of pipe (in): /__/__/./__/__/__/

3.b Wall thickness (in): /__/./__/__/__/

3.c SMYS (Specified Minimum Yield Strength) of pipe (psi): /__/__/__/,/__/__/__/

3.d Pipe specification: _____

3.e Pipe Seam ⇨ Specify:
○ Longitudinal ERW - High Frequency ○ Single SAW ○ Flash Welded
○ Longitudinal ERW - Low Frequency ○ DSAW ○ Continuous Welded
○ Longitudinal ERW – Unknown Frequency ○ Furnace Butt Welded
○ Spiral Welded ERW ○ Spiral Welded SAW ○ Spiral Welded DSAW
○ Lap Welded ○ Seamless ○ Other _____

3.f Pipe manufacturer: _____

3.g Year of manufacture: /__/__/__/__/

3.h Pipeline coating type at point of Accident
⇨ Specify:
○ Fusion Bonded Epoxy ○ Coal Tar ○ Asphalt ○ Polyolefin
○ Extruded Polyethylene ○ Field Applied Epoxy ○ Cold Applied Tape ○ Paint
○ Composite ○ None ○ Other _____

☐ Weld, including heat-affected zone ⇨ Specify: ○ Pipe Girth Weld ○ Other Butt Weld ○ Fillet Weld ○ Other_____

☐ Valve ○ Mainline ⇨ Specify: ○ Butterfly ○ Check ○ Gate ○ Plug ○ Ball ○ Globe ○ Other _____

3.i Mainline valve manufacturer: _____

3.j Year of manufacture: /__/__/__/__/

○ Relief Valve
○ Auxiliary or Other Valve

☐ Pump
☐ Meter/Prover
☐ Scraper/Pig Trap
☐ Sump/Separator
☐ Repair Sleeve or Clamp
☐ Hot Tap Equipment
☐ Stopple Fitting
☐ Flange
☐ Relief Line
☐ Auxiliary Piping (e.g. drain lines)
☐ Tubing
☐ Instrumentation

☐ Tank/Vessel ⇨ Specify: ○ Single Bottom System ○ Double Bottom System ○ Tank Shell ○ Chime ○ Roof/Roof Seal ○ Roof Drain System ○ Mixer ○ Pressure Vessel Head or Wall ○ Appurtenance ○ Other _____

☐ Other _____

4. Year item involved in Accident was installed: /__/__/__/__/__/

*5. Material involved in Accident: (*select only one)*

☐ Carbon Steel

☐ Material other than Carbon Steel ⇨ Specify: _____

*6. Type of Accident involved: *(select only one)*

☐ Mechanical Puncture ⇨ Approx. size: /__/__/__/__/./__/in. (axial) by /__/__/__/__/./__/in. (circumferential)

☐ Leak ⇨ Select Type: ○ Pinhole ○ Crack ○ Connection Failure ○ Seal or Packing ○ Other

☐ Rupture ⇨ Select Orientation: ○ Circumferential ○ Longitudinal ○ Other _____

Approx. size: /__/__/__/__/./__/ in. (widest opening) by /__/__/__/__/__/./__/in. (length circumferentially or axially)

☐ Overfill or Overflow

☐ Other ⇨ Describe: _____

**PART D – ADDITIONAL CONSEQUENCE INFORMATION**

1. Wildlife impact: ○ Yes ○ No

1.a If Yes, specify all that apply:

☐ Fish/aquatic

☐ Birds

☐ Terrestrial

*2. Soil contamination: ○ Yes ○ No

3. Long term impact assessment performed or planned: ○ Yes ○ No

4. Anticipated remediation: ○ Yes ○ No (not needed)

4.a If Yes, specify all that apply:

☐ Surface water ☐ Groundwater ☐ Soil ☐ Vegetation ☐ Wildlife

*5. Water contamination: ○ Yes ⇨ *(Complete 5.a – 5.c below)* ○ No

*5.a Specify all that apply:

☐ Ocean/Seawater

☐ Surface

☐ Groundwater

☐ Drinking water ⇨ *(Select one or both)* ○ Private Well ○ Public Water Intake

*5.b Estimated amount released in or reaching water: /___/___/___/,___/___/___/./___/___/ Barrels

*5.c Name of body of water, if commonly known: _____

*6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program? ○ Yes ○ No

*7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)? ○ Yes ○ No

7.a If Yes, specify HCA type(s): *(select all that apply)*

☐ Commercially Navigable Waterway
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
○ Yes ○ No

☐ High Population Area
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
○ Yes ○ No

☐ Other Populated Area
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
○ Yes ○ No

☐ Unusually Sensitive Area (USA) – Drinking Water
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
○ Yes ○ No

☐ Unusually Sensitive Area (USA) – Ecological
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
○ Yes ○ No

*8. Estimated cost to Operator:

8.a Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator $ /___/___/___/,___/___/___/,___/___/___/

8.b Estimated cost of commodity lost $ /___/___/___/,___/___/___/,___/___/___/

8.c Estimated cost of Operator's property damage & repairs $ /___/___/___/,___/___/___/,___/___/___/

8.d Estimated cost of Operator's emergency response $ /___/___/___/,___/___/___/,___/___/___/

8.e Estimated cost of Operator's environmental remediation $ /___/___/___/,___/___/___/,___/___/___/

8.f Estimated other costs $ /___/___/___/,___/___/___/,___/___/___/

Describe _____

8.g Estimated total costs (sum of above) $ /___/___/___/,___/___/___/,___/___/___/

**PART E – ADDITIONAL OPERATING INFORMATION**

*1. Estimated pressure at the point and time of the Accident (psig): /___/___/,/___/___/___/

*2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig): /___/___/,/___/___/___/

*3. Describe the pressure on the system or facility relating to the Accident: *(select only one)*

- ☐ Pressure did not exceed MOP
- ☐ Pressure exceeded MOP, but did not exceed 110% of MOP
- ☐ Pressure exceeded 110% of MOP

*4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?

- ☐ No
- ☐ Yes ⇨ (*Complete 4.a and 4.b below)*

*4.a Did the pressure exceed this established pressure restriction? ○ Yes ○ No

*4.b Was this pressure restriction mandated by PHMSA or the State? ○ PHMSA ○ State ○ Not mandated

*5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?

- ☐ No
- ☐ Yes ⇨ (*Complete 5.a – 5.f below)*

5.a Type of upstream valve used to initially isolate release source: ○ Manual ○ Automatic ○ Remotely Controlled

5.b Type of downstream valve used to initially isolate release source: ○ Manual ○ Automatic ○ Remotely Controlled ○ Check Valve

5.c Length of segment initially isolated between valves (ft): /___/___/___/,/___/___/___/

5.d Is the pipeline configured to accommodate internal inspection tools?

- ☐ Yes
- ☐ No ⇨ Which physical features limit tool accommodation? *(select all that apply)*
  - ○ Changes in line pipe diameter
  - ○ Presence of unsuitable mainline valves
  - ○ Tight or mitered pipe bends
  - ○ Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)
  - ○ Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)
  - ○ Other ⇨ Describe:_____

5.e For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?

- ☐ No
- ☐ Yes ⇨ Which operational factors complicate execution? *(select all that apply)*
  - ○ Excessive debris or scale, wax, or other wall build-up
  - ○ Low operating pressure(s)
  - ○ Low flow or absence of flow
  - ○ Incompatible commodity
  - ○ Other ⇨ Describe:_____

5.f Function of pipeline system: *(select only one)*

- ☐ > 20% SMYS Regulated Trunkline/Transmission
- ☐ ≤ 20% SMYS Regulated Trunkline/Transmission
- ☐ ≤ 20% SMYS "Unregulated" Trunkline/Transmission
- ☐ > 20% SMYS Regulated Gathering
- ☐ ≤ 20% SMYS Regulated Gathering
- ☐ ≤ 20% SMYS "Unregulated" Gathering

*6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?

☐ No

☐ Yes ⇨ 6.a Was it operating at the time of the Accident? ○ Yes ○ No

6.b Was it fully functional at the time of the Accident? ○ Yes ○ No

6.c Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident? ○ Yes ○ No

6.d Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident? ○ Yes ○ No

*7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?

☐ No

☐ Yes ⇨ 7.a Was it operating at the time of the Accident? ○ Yes ○ No

7.b Was it fully functional at the time of the Accident? ○ Yes ○ No

7.c Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident? ○ Yes ○ No

7.d Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident? ○ Yes ○ No

*8. How was the Accident initially identified for the Operator? *(select only one)*

☐ CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
☐ Static Shut-in Test or Other Pressure or Leak Test
☐ Controller
☐ Air Patrol
☐ Notification from Public
☐ Notification from Third Party that caused the Accident
☐ Local Operating Personnel, including contractors
☐ Ground Patrol by Operator or its contractor
☐ Notification from Emergency Responder
☐ Other _____

*8.a If "Controller", "Local Operating Personnel, including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 8, specify the following: *(select only one)*

○ Operator employee ○ Contractor working for the Operator

*9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident? *(select only one)*

☐ Yes, but the investigation of the control room and/or controller actions has not yet been completed by the Operator *(Supplemental Report required)*

☐ No, the facility was not monitored by a controller(s) at the time of the Accident

☐ No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the Operator did not investigate)*

_____
_____
_____

☐ Yes, specify investigation result(s): *(select all that apply)*

○ Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator) and other factors associated with fatigue

○ Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator) and other factors associated with fatigue *(provide an explanation for why not)*

_____
_____
_____

○ Investigation identified no control room issues
○ Investigation identified no controller issues
○ Investigation identified incorrect controller action or controller error
○ Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response
○ Investigation identified incorrect procedures
○ Investigation identified incorrect control room equipment operation
○ Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response
○ Investigation identified areas other than those above ⇨ Describe: _____

_____
_____
_____

| PART F – DRUG & ALCOHOL TESTING INFORMATION | |
|---|---|

*1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?

O No

O Yes ⇨ *1.a Specify how many were tested: /___/___/

*1.b Specify how many failed: /___/___/

*2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?

O No

O Yes ⇨ *2.a Specify how many were tested: /___/___/

*2.b Specify how many failed: /___/___/

| PART G – APPARENT CAUSE | ***Select only one box from PART G in the shaded column on the left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing, or root causes of the Accident in the narrative (PART H).*** |
|---|---|

## G1 - Corrosion Failure – *only one **sub-cause** can be picked from shaded left-hand column

**☐ External Corrosion**

*1. Results of visual examination:
- ○ Localized Pitting ○ General Corrosion
- ○ Other _____

*2. Type of corrosion: *(select all that apply)*
- ○ Galvanic ○ Atmospheric ○ Stray Current ○ Microbiological ○ Selective Seam
- ○ Other _____

*3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*
- ○ Field examination ○ Determined by metallurgical analysis
- ○ Other _____

*4. Was the failed item buried under the ground?
- ○ Yes ⇨ *4.a Was failed item considered to be under cathodic protection at the time of the Accident?
  - ○ Yes ⇨ Year protection started: /__/__/__/__/
  - ○ No

  *4.b Was shielding, tenting, or disbonding of coating evident at the point of the Accident?
  - ○ Yes ○ No

  *4.c Has one or more Cathodic Protection Survey been conducted at the point of the Accident?
  - ○ Yes, CP Annual Survey ⇨ Most recent year conducted: /__/__/__/__/
  - ○ Yes, Close Interval Survey ⇨ Most recent year conducted: /__/__/__/__/
  - ○ Yes, Other CP Survey ⇨ Most recent year conducted: /__/__/__/__/
  - ○ No
- ○ No ⇨ 4.d Was the failed item externally coated or painted? ○ Yes ○ No

*5. Was there observable damage to the coating or paint in the vicinity of the corrosion?
○ Yes ○ No

**☐ Internal Corrosion**

*6. Results of visual examination:
- ○ Localized Pitting ○ General Corrosion ○ Not cut open
- ○ Other _____

*7. Cause of corrosion: *(select all that apply)*
- ○ Corrosive Commodity ○ Water drop-out/Acid ○ Microbiological ○ Erosion
- ○ Other _____

*8. The cause(s) of corrosion selected in Question 7 is based on the following: *(select all that apply)*
- ○ Field examination ○ Determined by metallurgical analysis
- ○ Other _____

*9. Location of corrosion: *(select all that apply)*
- ○ Low point in pipe ○ Elbow ○ Other_____

*10. Was the commodity treated with corrosion inhibitors or biocides? ○ Yes ○ No

11. Was the interior coated or lined with protective coating? ○ Yes ○ No

12. Were cleaning/dewatering pigs (or other operations) routinely utilized?
- ○ Not applicable - Not mainline pipe ○ Yes ○ No

13. Were corrosion coupons routinely utilized?
- ○ Not applicable - Not mainline pipe ○ Yes ○ No

**Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.**

14. List the year of the most recent inspections:
- 14.a API Std 653 Out-of-Service Inspection /__/__/__/__/__/ ○ No Out-of-Service Inspection completed
- 14.b API Std 653 In-Service Inspection /__/__/__/__/__/ ○ No In-Service Inspection completed

**Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.**

15. Has one or more internal inspection tool collected data at the point of the Accident?
O Yes O No

15.a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

- O Magnetic Flux Leakage Tool /__/__/__/__/
- O Ultrasonic /__/__/__/__/
- O Geometry /__/__/__/__/
- O Caliper /__/__/__/__/
- O Crack /__/__/__/__/
- O Hard Spot /__/__/__/__/
- O Combination Tool /__/__/__/__/
- O Transverse Field/Triaxial /__/__/__/__/
- O Other _____ /__/__/__/__/

16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?
O Yes ⇨ Most recent year tested: /__/__/__/__/ Test pressure (psig): /__/__/__/__/__/
O No

17. Has one or more Direct Assessment been conducted on this segment?
O Yes, and an investigative dig was conducted at the point of the Accident ⇨ Most recent year conducted: /__/__/__/__/
O Yes, but the point of the Accident was not identified as a dig site ⇨ Most recent year conducted: /__/__/__/__/
O No

18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?
O Yes O No

18.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:

- O Radiography /__/__/__/__/
- O Guided Wave Ultrasonic /__/__/__/__/
- O Handheld Ultrasonic Tool /__/__/__/__/
- O Wet Magnetic Particle Test /__/__/__/__/
- O Dry Magnetic Particle Test /__/__/__/__/
- O Other _____ /__/__/__/__/

## G2 - Natural Force Damage - *only one **sub-cause** can be picked from shaded left-hand column

| | |
|---|---|
| ☐ **Earth Movement, NOT due to Heavy Rains/Floods** | 1. Specify: O Earthquake O Subsidence O Landslide O Other _____ |
| ☐ **Heavy Rains/Floods** | 2. Specify: O Washout/Scouring O Flotation O Mudslide O Other _____ |
| ☐ **Lightning** | 3. Specify: O Direct hit O Secondary impact such as resulting nearby fires |
| ☐ **Temperature** | 4. Specify: O Thermal Stress O Frost Heave O Frozen Components O Other _____ |
| ☐ **High Winds** | |
| ☐ **Other Natural Force Damage** | *5. Describe: _____ |

**Complete the following if any Natural Force Damage sub-cause is selected.**

*6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event? O Yes O No

*6.a If Yes, specify: (*select all that apply*) O Hurricane O Tropical Storm O Tornado O Other _____

## G3 – Excavation Damage - *only one **sub-cause** can be picked from shaded left-hand column

| | |
|---|---|
| ☐ **Excavation Damage by Operator (First Party)** | |
| ☐ **Excavation Damage by Operator's Contractor (Second Party)** | |
| ☐ **Excavation Damage by Third Party** | |
| ☐ **Previous Damage due to Excavation Activity** | **Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.** |

1. Has one or more internal inspection tool collected data at the point of the Accident?
   ○ Yes ○ No

   1.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

   - ○ Magnetic Flux Leakage / / / / /
   - ○ Ultrasonic / / / / /
   - ○ Geometry / / / / /
   - ○ Caliper / / / / /
   - ○ Crack / / / / /
   - ○ Hard Spot / / / / /
   - ○ Combination Tool / / / / /
   - ○ Transverse Field/Triaxial / / / / /
   - ○ Other _____ / / / / /

2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained? ○ Yes ○ No

3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?

   ○ Yes ⇨ Most recent year tested: / / / / /
   Test pressure (psig): / / /, / / / /

   ○ No

4. Has one or more Direct Assessment been conducted on the pipeline segment?

   ○ Yes, and an investigative dig was conducted at the point of the Accident
   ⇨ Most recent year conducted: / / / / /

   ○ Yes, but the point of the Accident was not identified as a dig site
   ⇨ Most recent year conducted: / / / / /

   ○ No

5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?
   ○ Yes ○ No

   5.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:

   - ○ Radiography / / / / /
   - ○ Guided Wave Ultrasonic / / / / /
   - ○ Handheld Ultrasonic Tool / / / / /
   - ○ Wet Magnetic Particle Test / / / / /
   - ○ Dry Magnetic Particle Test / / / / /
   - ○ Other _____ / / / / /

**Complete the following if Excavation Damage by Third Party is selected as the sub-cause.**

6. Did the Operator get prior notification of the excavation activity? ○ Yes ○ No

   *6.a If Yes, Notification received from: *(select all that apply)* ○ One-Call System ○ Excavator ○ Contractor ○ Landowner

**Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.**

7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)? ○Yes ○ No

*8. Right-of-Way where event occurred: *(select all that apply)*

☐ Public ⇨ Specify: ○ City Street ○ State Highway ○ County Road ○ Interstate Highway ○ Other

☐ Private ⇨ Specify: ○ Private Landowner ○ Private Business ○ Private Easement

☐ Pipeline Property/Easement
☐ Power/Transmission Line
☐ Railroad
☐ Dedicated Public Utility Easement
☐ Federal Land
☐ Data not collected
☐ Unknown/Other

*9. Type of excavator: *(select only one)*

○ Contractor ○ County ○ Developer ○ Farmer ○ Municipality ○ Occupant
○ Railroad ○ State ○ Utility ○ Data not collected ○ Unknown/Other

*10. Type of excavation equipment: *(select only one)*

○ Auger ○ Backhoe/Trackhoe ○ Boring ○ Drilling ○ Directional Drilling
○ Explosives ○ Farm Equipment ○ Grader/Scraper ○ Hand Tools ○ Milling Equipment
○ Probing Device ○ Trencher ○ Vacuum Equipment ○ Data not collected ○ Unknown/Other

*11. Type of work performed: *(select only one)*

○ Agriculture ○ Cable TV ○ Curb/Sidewalk ○ Building Construction ○ Building Demolition
○ Drainage ○ Driveway ○ Electric ○ Engineering/Surveying ○ Fencing
○ Grading ○ Irrigation ○ Landscaping ○ Liquid Pipeline ○ Milling
○ Natural Gas ○ Pole ○ Public Transit Authority ○ Railroad Maintenance ○ Road Work
○ Sewer (Sanitary/Storm) ○ Site Development ○ Steam ○ Storm Drain/Culvert ○Street Light
○ Telecommunications ○Traffic Signal ○ Traffic Sign ○ Water ○ Waterway Improvement
○ Data not collected ○ Unknown/Other

*12. Was the One-Call Center notified? ○ Yes ○ No

*12.a If Yes, specify ticket number: /__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/

*12.b If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:
_____

*13. Type of Locator: ○ Utility Owner ○ Contract Locator ○ Data not collected ○ Unknown/Other

*14. Were facility locate marks visible in the area of excavation? ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*15. Were facilities marked correctly? ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*16. Did the damage cause an interruption in service? ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*16.a If Yes, specify duration of the interruption: /___/___/___/___/ hours

*(This CGA-DIRT section continued on next page with Question 17.)*

*17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well)*:

☐ One-Call Notification Practices Not Sufficient: *(select only one)*

- ○ No notification made to the One-Call Center
- ○ Notification to One-Call Center made, but not sufficient
- ○ Wrong information provided

☐ Locating Practices Not Sufficient: *(select only one)*

- ○ Facility could not be found/located
- ○ Facility marking or location not sufficient
- ○ Facility was not located or marked
- ○ Incorrect facility records/maps

☐ Excavation Practices Not Sufficient: *(select only one)*

- ○ Excavation practices not sufficient (other)
- ○ Failure to maintain clearance
- ○ Failure to maintain the marks
- ○ Failure to support exposed facilities
- ○ Failure to use hand tools where required
- ○ Failure to verify location by test-hole (pot-holing)
- ○ Improper backfilling

☐ One-Call Notification Center Error

☐ Abandoned Facility

☐ Deteriorated Facility

☐ Previous Damage

☐ Data Not Collected

☐ Other / None of the Above *(explain)*_____
_____
_____
_____

## G4 - Other Outside Force Damage - *only one **sub-cause** can be picked from shaded left-hand column

| | |
|---|---|
| ☐ **Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Accident** | |
| ☐ **Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation** | 1. Vehicle/Equipment operated by: *(select only one)*<br>O Operator O Operator's Contractor O Third Party |
| ☐ **Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring** | 2. Select one or more of the following IF an extreme weather event was a factor:<br>O Hurricane O Tropical Storm O Tornado<br>O Heavy Rains/Flood O Other _____ |
| ☐ **Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation** | |
| ☐ **Electrical Arcing from Other Equipment or Facility** | |
| ☐ **Previous Mechanical Damage NOT Related to Excavation** | **Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.**<br>3. Has one or more internal inspection tool collected data at the point of the Accident?<br>O Yes O No<br>3.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:<br>O Magnetic Flux Leakage /__/__/__/__/<br>O Ultrasonic /__/__/__/__/<br>O Geometry /__/__/__/__/<br>O Caliper /__/__/__/__/<br>O Crack /__/__/__/__/<br>O Hard Spot /__/__/__/__/<br>O Combination Tool /__/__/__/__/<br>O Transverse Field/Triaxial /__/__/__/__/<br>O Other _____ /__/__/__/__/<br>4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained? O Yes O No<br>5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?<br>O Yes ⇨ Most recent year tested: /__/__/__/__/<br>Test pressure (psig): /__/__/,/__/__/__/<br>O No<br>6. Has one or more Direct Assessment been conducted on the pipeline segment?<br>O Yes, and an investigative dig was conducted at the point of the Accident<br>⇨ Most recent year conducted: /__/__/__/__/<br>O Yes, but the point of the Accident was not identified as a dig site<br>⇨ Most recent year conducted: /__/__/__/__/<br>O No<br>*(This section continued on next page with Question 7.)* |

| | |
|---|---|
| | 7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?<br>O Yes O No<br>7.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:<br>O Radiography /___/___/___/___/<br>O Guided Wave Ultrasonic /___/___/___/___/<br>O Handheld Ultrasonic Tool /___/___/___/___/<br>O Wet Magnetic Particle Test /___/___/___/___/<br>O Dry Magnetic Particle Test /___/___/___/___/<br>O Other _____ /___/___/___/___/ |
| ☐ **Intentional Damage** | 8. Specify:<br>O Vandalism O Terrorism<br>O Theft of transported commodity O Theft of equipment<br>O Other _____ |
| ☐ **Other Outside Force Damage** | *9. Describe: _____ |

## G5 - Material Failure of Pipe or Weld

**Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."**

*Only one **sub-cause** can be picked from shaded left-hand column

1. The sub-cause selected below is based on the following: *(select all that apply)*

☐ Field Examination ☐ Determined by Metallurgical Analysis ☐ Other Analysis_____

☐ Sub-cause is Tentative or Suspected; Still Under Investigation *(Supplemental Report required)*

| | |
|---|---|
| ☐ **Construction-, Installation-, or Fabrication-related** | 2. List contributing factors: *(select all that apply)*<br>☐ Fatigue- or Vibration-related:<br>○ Mechanically-induced prior to installation (such as during transport of pipe)<br>○ Mechanical Vibration<br>○ Pressure-related<br>○ Thermal<br>○ Other _____<br>☐ Mechanical Stress<br>☐ Other _____ |
| ☐ **Original Manufacturing-related (NOT girth weld or other welds formed in the field)** | |
| ☐ **Environmental Cracking-related** | 3. Specify: ○ Stress Corrosion Cracking ○ Sulfide Stress Cracking<br>○ Hydrogen Stress Cracking ○ Other _____ |

**Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.**

*4. Additional factors: *(select all that apply)* ○ Dent ○ Gouge ○ Pipe Bend ○ Arc Burn ○ Crack ○ Lack of Fusion
○ Lamination ○ Buckle ○ Wrinkle ○ Misalignment ○ Burnt Steel
○ Other _____

*5. Has one or more internal inspection tool collected data at the point of the Accident? ○ Yes ○ No

*5.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

○ Magnetic Flux Leakage Tool /__/__/__/__/
○ Ultrasonic /__/__/__/__/
○ Geometry /__/__/__/__/
○ Caliper /__/__/__/__/
○ Crack /__/__/__/__/
○ Hard Spot /__/__/__/__/
○ Combination Tool /__/__/__/__/
○ Transverse Field/Triaxial /__/__/__/__/
○ Other _____ /__/__/__/__/

*6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?
○ Yes ⇨ Most recent year tested: /__/__/__/__/ Test pressure (psig): /__/__/,/__/__/__/
○ No

*7. Has one or more Direct Assessment been conducted on the pipeline segment?
○ Yes, and an investigative dig was conducted at the point of the Accident ⇨ Most recent year conducted: /__/__/__/__/
○ Yes, but the point of the Accident was not identified as a dig site ⇨ Most recent year conducted: /__/__/__/__/
○ No

*8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?
○ Yes ○ No

*8.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:

○ Radiography /__/__/__/__/
○ Guided Wave Ultrasonic /__/__/__/__/
○ Handheld Ultrasonic Tool /__/__/__/__/
○ Wet Magnetic Particle Test /__/__/__/__/
○ Dry Magnetic Particle Test /__/__/__/__/
○ Other _____ /__/__/__/__/

## G6 - Equipment Failure - *only one **sub-cause** can be picked from shaded left-hand column

| | |
|---|---|
| ☐ **Malfunction of Control/Relief Equipment** | 1. Specify: *(select all that apply)*<br>○ Control Valve ○ Instrumentation ○ SCADA<br>○ Communications ○ Block Valve ○ Check Valve<br>○ Relief Valve ○ Power Failure ○ Stopple/Control Fitting<br>○ ESD System Failure<br>○ Other _____ |
| ☐ **Pump or Pump-related Equipment** | 2. Specify: ○ Seal/Packing Failure ○ Body Failure ○ Crack in Body<br>○ Appurtenance Failure<br>○ Other _____ |
| ☐ **Threaded Connection/Coupling Failure** | 3. Specify: ○ Pipe Nipple ○ Valve Threads ○ Mechanical Coupling<br>○ Threaded Pipe Collar ○ Threaded Fitting<br>○ Other _____ |
| ☐ **Non-threaded Connection Failure** | 4. Specify: ○ O-Ring ○ Gasket ○ Seal (NOT pump seal) or Packing<br>○ Other _____ |
| ☐ **Defective or Loose Tubing or Fitting** | |
| ☐ **Failure of Equipment Body (except Pump), Tank Plate, or other Material** | |
| ☐ **Other Equipment Failure** | *5. Describe: _____<br>_____ |

**Complete the following if any Equipment Failure sub-cause is selected.**

*6. Additional factors that contributed to the equipment failure: *(select all that apply)*

- ○ Excessive vibration
- ○ Overpressurization
- ○ No support or loss of support
- ○ Manufacturing defect
- ○ Loss of electricity
- ○ Improper installation
- ○ Mismatched items (different manufacturer for tubing and tubing fittings)
- ○ Dissimilar metals
- ○ Breakdown of soft goods due to compatibility issues with transported commodity
- ○ Valve vault or valve can contributed to the release
- ○ Alarm/status failure
- ○ Misalignment
- ○ Thermal stress
- ○ Other _____

## G7 - Incorrect Operation - *only one **sub-cause** can be picked from shaded left-hand column

| | |
|---|---|
| ☐ **Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage** | |
| ☐ **Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow** | 1. Specify: ○ Valve misalignment ○ Incorrect reference data/calculation ○ Miscommunication ○ Inadequate monitoring ○ Other _____ |
| ☐ **Valve Left or Placed in Wrong Position, but NOT Resulting in a Tank, Vessel, or Sump/Separator Overflow or Facility Overpressure** | |
| ☐ **Pipeline or Equipment Overpressured** | |
| ☐ **Equipment Not Installed Properly** | |
| ☐ **Wrong Equipment Specified or Installed** | |
| ☐ **Other Incorrect Operation** | *2. Describe: _____ |

**Complete the following if any Incorrect Operation sub-cause is selected.**

*3. Was this Accident related to: *(select all that apply)*
- ○ Inadequate procedure
- ○ No procedure established
- ○ Failure to follow procedure
- ○ Other: _____

*4. What category type was the activity that caused the Accident:
- ○ Construction
- ○ Commissioning
- ○ Decommissioning
- ○ Right-of-Way activities
- ○ Routine maintenance
- ○ Other maintenance
- ○ Normal operating conditions
- ○ Non-routine operating conditions (abnormal operations or emergencies)

*5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program? ○ Yes ○ No

*5.a If Yes, were the individuals performing the task(s) qualified for the task(s)?
- ○ Yes, they were qualified for the task(s)
- ○ No, but they were performing the task(s) under the direction and observation of a qualified individual
- ○ No, they were not qualified for the task(s) nor were they performing the task(s) under the direction and observation of a qualified individual

## G8 – Other Accident Cause - *only one **sub-cause** can be picked from shaded left-hand column

| | |
|---|---|
| ☐ **Miscellaneous** | *1. Describe: _____ _____ |
| ☐ **Unknown** | *2. Specify: ○ Investigation complete, cause of Accident unknown ○ Still under investigation, cause of Accident to be determined* *(*Supplemental Report required)* |

**PART H – NARRATIVE DESCRIPTION OF THE ACCIDENT** *(Attach additional sheets as necessary)*

***PART I – PREPARER AND AUTHORIZED SIGNATURE**

*Preparer's Name (type or print)

Preparer's Telephone Number

Preparer's Title (type or print)

Preparer's E-mail Address

Preparer's Facsimile Number

Authorized Signature

*Date

Authorized Signature Telephone Number

*Authorized Signature's Name (type or print)

Authorized Signature's Title (type or print)

Authorized Signature's E-mail Address

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.

OMB NO: 2137-0047

EXPIRATION DATE: 01/31/2013

U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

# ACCIDENT REPORT – HAZARDOUS LIQUID PIPELINE SYSTEMS

**This document identifies fields used in the accompanying text files**

Report Date – No.
REPORT_NUMBER ,
SUPPLEMENTAL_NUMBER

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0047. Public reporting for this collection of information is estimated to be approximately 10 hours per response (5 hours for a small release), including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

**INSTRUCTIONS**

***Important:*** *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline. Note: Certain low consequence accidents only require the information indicated in the shaded fields.*

**PART A – KEY REPORT INFORMATION**

*Report Type: *(select all that apply)* ☐ Original ☐ Supplemental ☐ Final
REPORT_TYPE

*1. Operator's OPS-issued Operator Identification Number (OPID): / / / / / / OPERATOR_ID

*2. Name of Operator NAME, OPERATOR_STREET_ADDRESS, OPERATOR_CITY_NAME, OPERATOR_STATE_ABBREVIATION, OPERATOR_POSTAL_CODE

*3. Address of Operator:

*3.a _____
(Street Address)

*3.b _____ (City)

*3.c State: / / /

*3.d Zip Code: / / / / / / - / / / / /

*4. Local time *(24-hr clock)* and date of the Accident:
LOCAL_DATETIME
Hour Month Day Year

*5. Location of Accident:
Latitude: LOCATION_LATITUDE
Longitude: - LOCATION_LONGITUDE

6. National Response Center Report Number (if applicable):
NRC_RPT_NUM

7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):
NRC_RPT_DATETIME
Hour Month Day Year

*8. Commodity released: *(select only one, based on predominant volume released)*

COMMODITY_RELEASED_TYPE

☐ Crude Oil COMMODITY_SUBTYPE

☐ Refined and/or Petroleum Product (non-HVL) which is a Liquid at Ambient Conditions

- ○ Gasoline (non-Ethanol) ○ Diesel, Fuel Oil, Kerosene, Jet Fuel
- ○ Mixture of Refined Products (transmix or other mixture)
- ○ Other ⇨ Name: _____ COMMODITY_DETAILS

☐ HVL or Other Flammable or Toxic Fluid which is a Gas at Ambient Conditions

- ○ Anhydrous Ammonia
- ○ LPG (Liquefied Petroleum Gas) / NGL (Natural Gas Liquid)
- ○ Other HVL ⇨ Name: _____ COMMODITY_DETAILS

☐ $CO_2$ (Carbon Dioxide)

☐ Biofuel / Alternative Fuel (including ethanol blends)

- ○ Fuel Grade Ethanol ○ Ethanol Blend ⇨ % Ethanol: BLEND_DETAILS
- ○ Biodiesel ⇨ Blend (e.g. B2, B20, B100: BLEND_DETAILS ○ Other ⇨ Name: BIO_DIESEL_DETAILS

*9. Estimated volume of commodity released unintentionally: UNINTENTIONAL_RELEASE Barrels

10. Estimated volume of intentional and/or controlled release/blowdown: INTENTIONAL_RELEASE Barrels

*11. Estimated volume of commodity recovered: GAS_RECOVERED Barrels

*12. Were there fatalities? ○ Yes ○ No FATALITY_IND

If Yes, specify the number in each category:

- *12.a Operator employees / / / / / NUM_EMP_FATALITIES
- *12.b Contractor employees working for the Operator / / / / / NUM_CONTR_FATALITIES
- *12.c Non-Operator emergency responders / / / / / NUM_ER_FATALITIES
- *12.d Workers working on the right-of-way, but NOT associated with this Operator / / / / / NUM_WORKER_FATALITIES
- *12.e General public / / / / / NUM_GP_FATALITIES
- 12.f Total fatalities FATAL / / / / /

*13. Were there injuries ○ Yes ○ No INJURY_IND

If Yes, specify the number in each category:

- *13.a Operator employees / / / / / NUM_EMP_INJURIES
- *13.b Contractor employees working for the Operator / / / / / NUM_CONTR_INJURIES
- *13.c Non-Operator emergency responders / / / / / NUM_ER_INJURIES
- *13.d Workers working on the right-of-way, but NOT associated with this Operator / / / / / NUM_WORKER_INJURIES
- *13.e General public / / / / / NUM_GP_INJURIES
- 13.f Total injuries INJURE / / / / /

14. Was the pipeline/facility shut down due to the Accident? SHUTDOWN_DUE_ACCIDENT_IND

○ Yes ○ No ⇨ Explain: SHUTDOWN_EXPLAIN

If Yes, complete Questions 14.a and 14.b: *(use local time, 24-hr clock)*

14.a Local time and date of shutdown SHUTDOWN_DATETIME
Hour Month Day Year

14.b Local time pipeline/facility restarted RESTART_DATETIME ○ Still shut down* STILL_SHUTDOWN_IND
Hour Month Day Year *(*Supplemental Report required)*

*15. Did the commodity ignite? ○ Yes ○ No IGNITE_IND

*16. Did the commodity explode? ○ Yes ○ No EXPLODE_IND

17. Number of general public evacuated: / / / /,/ / / / NUM_PUB_EVACUATED

18. Time sequence: *(use local time, 24-hour clock)*

18.a Local time Operator identified Accident / / / / / INCIDENT_IDENTIFIED_DATETIME
Hour Month Day Year

18.b Local time Operator resources arrived on site / / / / / / / / / / / / ON_SITE_DATETIME
Hour Month Day Year

## PART B – ADDITIONAL LOCATION INFORMATION

*1. Was the origin of the Accident onshore? ON_OFF_SHORE

○ Yes (VALUE=ONSHORE) *(Complete Questions 2-12)* ○ No (VALUE=OFFSHORE) *(Complete Questions 13-15)*

If **Onshore**:

*2. State: /___/___/ ONSHORE_STATE_ABBREVIATION

*3. Zip Code: /___/___/___/___/___/ - _ONSHORE_POSTAL_CODE

4._ONSHORE_CITY_NAME City 5 ONSHORE_COUNTY_NAME County or Parish

6. Operator-designated location: DESIGNATED_LOCATION

☐ Milepost/Valve Station

☐ Survey Station No.

DESIGNATED_NAME

7. Pipeline/Facility name: PIPE_FAC_NAME

8. Segment name/ID: SEGMENT_NAME

*9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)? ○ Yes ○ No FEDERAL

*10. Location of Accident: LOCATION_TYPE

☐ Totally contained on Operator-controlled property

☐ Originated on Operator-controlled property, but then flowed or migrated off the property

☐ Pipeline right-of-way

*11. Area of Accident (as found): INCIDENT_AREA_TYPE, INCIDENT_AREA_SUBTYPE

☐ Tank, including attached appurtenances

☐ Underground ⇨ Specify: ○ Under soil

○ Under a building ○ Under pavement

○ Exposed due to excavation

○ In underground enclosed space (e.g., vault)

○ Other _____INCIDENT_AREA_DETAILS

Depth-of-Cover (in): _DEPTH_OF_COVER

☐ Aboveground ⇨ Specify:

○ Typical aboveground facility piping or appurtenance

○ Overhead crossing

○ In or spanning an open ditch

○ Inside a building ○ Inside other enclosed space

○ Other _____ INCIDENT_AREA_DETAILS

☐ Transition Area ⇨ Specify:

○ Soil/air interface ○ Wall sleeve

○ Pipe support or other close contact area

○ Other _____INCIDENT_AREA_DETAILS

*12. Did Accident occur in a crossing?: CROSSING

If Yes, specify type below:

☐ Bridge crossing ⇨ Specify: ○ Cased ○ Uncased

☐ Railroad crossing ⇨ *(select all that apply)*

○ Cased ○ Uncased ○ Bored/drilled

☐ Road crossing ⇨ *(select all that apply)*

○ Cased ○ Uncased ○ Bored/drilled

☐ Water crossing

⇨ Specify: ○ Cased ○ Uncased

Name of body of water, if commonly known:

_____ WATER_NAME

Approx. water depth (ft) at the point of the Accident:

/___/,/___/___/___/___/ WATER_DEPTH

*(select only one of the following)* WATER_SUB_TYPE

○ Shoreline/Bank crossing

○ Below water, pipe in bored/drilled crossing

○ Below water, pipe buried below bottom (NOT in bored/drilled crossing)

○ Below water, pipe on or above bottom

If **Offshore**:

*13. Approximate water depth (ft.) at the point of the Accident:

/___/___/,/___/___/___/___/ OFF_WATER_DEPTH

*14. Origin of Accident: OFF_ACCIDENT_ORIGIN

☐ In State waters

⇨ Specify: State: /___/___/

OFFSHORE_STATE_ABBREVIATION

Area: _____

OFF_INSTATE_AREA

Block/Tract #: /___/___/___/___/___/

OFF_INSTATE_BLOCK

Nearest County/Parish: _____

OFFSHORE_COUNTY_NAME

☐ On the Outer Continental Shelf (OCS)

⇨ Specify: Area: _____ OFF_OCS_AREA

Block #: /___/___/___/___/___/ OFF_OCS_BLOCK

*15. Area of Accident: *(select only one)*OFF_AREA_ACCIDENT_TYPE

☐ Shoreline/Bank crossing or shore approach

☐ Below water, pipe buried or jetted below seabed

☐ Below water, pipe on or above seabed

☐ Splash Zone of riser

☐ Portion of riser outside of Splash Zone, including riser bend

☐ Platform

BRIDGE_CROSSING_IND, BRIDGE_TYPE

RAILROAD_CROSSING_IND, RAILROAD_TYPE

ROAD_CROSSING_IND, ROAD_TYPE

WATER_CROSSING_IND, WATER_TYPE

## PART C – ADDITIONAL FACILITY INFORMATION

*1. Is the pipeline or facility: PIPE_FACILITY_TYPE

- ☐ Interstate
- ☐ Intrastate

*2. Part of system involved in Accident: *(select only one)* SYSTEM_PART_INVOLVED SYSTEM_SUBPART_INVOLVED

- ☐ Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances ⇨ ○ Atmospheric or Low Pressure ○ Pressurized
- ☐ Onshore Terminal/Tank Farm Equipment and Piping
- ☐ Onshore Equipment and Piping Associated with Belowground Storage
- ☐ Onshore Pump/Meter Station Equipment and Piping
- ☐ Onshore Pipeline, Including Valve Sites
- ☐ Offshore Platform/Deepwater Port, Including Platform-mounted Equipment and Piping
- ☐ Offshore Pipeline, Including Riser and Riser Bend

*3. Item involved in Accident: *(select only one)* ITEM_NVOLVED

☐ Pipe PIPE_TYPE ⇨ Specify: ○ Pipe Body ○ Pipe Seam

3.a Nominal diameter of pipe (in): _____ PIPE_DIAMETER

3.b Wall thickness (in): _____ PIPE_WALL_THICKNESS

3.c SMYS (Specified Minimum Yield Strength) of pipe (psi): _____ PIPE_SMYS

3.d Pipe specification: _____ PIPE_SPECIFICATION

3.e Pipe Seam ⇨ Specify: PIPE_SEAM_TYPE
○ Longitudinal ERW - High Frequency ○ Single SAW ○ Flash Welded
○ Longitudinal ERW - Low Frequency ○ DSAW ○ Continuous Welded
○ Longitudinal ERW – Unknown Frequency ○ Furnace Butt Welded
○ Spiral Welded ERW ○ Spiral Welded SAW ○ Spiral Welded DSAW
○ Lap Welded ○ Seamless ○ Other ___ PIPE_SEAM_DETAILS

3.f Pipe manufacturer: _____ PIPE_MANUFACTURER

3.g Year of manufacture: _____ PIPE_MANUFACTURE_YEAR

3.h Pipeline coating type at point of Accident PIPE_COATING_TYPE
⇨ Specify: ○ Fusion Bonded Epoxy ○ Coal Tar ○ Asphalt ○ Polyolefin
○ Extruded Polyethylene ○ Field Applied Epoxy ○ Cold Applied Tape ○ Paint
○ Composite ○ None ○ Other _____ PIPE_COATING_DETAILS

☐ Weld, including heat-affected zone WELD_SUBTYPE
⇨ Specify: ○ Pipe Girth Weld ○ Other Butt Weld ○ Fillet Weld ○ Other_____ WELD_DETAILS

☐ Valve VALVE_TYPE
○ Mainline ⇨ VALVE_MAINLINE_TYPESpecify:
○ Butterfly ○ Check ○ Gate ○ Plug ○ Ball ○ Globe ○ Other VALVE_MAINLINE_DETAILS
3.i Mainline valve manufacturer: _____ VALVE_MANUFACTURER
3.j Year of manufacture: _____ VALVE_MANUFACTURE_YEAR

○ Relief Valve
○ Auxiliary or Other Valve

☐ Pump
☐ Meter/Prover
☐ Scraper/Pig Trap
☐ Sump/Separator
☐ Repair Sleeve or Clamp
☐ Hot Tap Equipment
☐ Stopple Fitting
☐ Flange
☐ Relief Line
☐ Auxiliary Piping (e.g. drain lines)
☐ Tubing
☐ Instrumentation TANK_VESSEL_SUBYTPE

☐ Tank/Vessel ⇨ Specify: ○ Single Bottom System ○ Double Bottom System ○ Tank Shell ○ Chime
○ Roof/Roof Seal ○ Roof Drain System ○ Mixer ○ Pressure Vessel Head or Wall
○ Appurtenance ○ Other _____ TANK_VESSEL_DETAILS

☐ Other _____ ITEM_INVOLVED_DETAILS

4. Year item involved in Accident was installed: _____ INSTALLATION_YEAR

*5. Material involved in Accident: (*select only one*) MATERIAL_NVOLVED

☐ Carbon Steel

☐ Material other than Carbon Steel ⇨ Specify: _____ MATERIAL_DETAILS

*6. Type of Accident involved: *(select only one)* RELEASE_TYPE

☐ Mechanical Puncture ⇨ Approx. size: PUNCTURE_AXIAL, PUNCTURE_CIRCUM

☐ Leak ⇨ LEAK_TYPE ○ Pinhole ○ Crack ○ Connection Failure ○ Seal or Packing ○ Other LEAK_TYPE_OTHER

☐ Rupture ⇨ RUPTURE_ORIENT Select Orientation: ○ Circumferential ○ Longitudinal ○ Other RUPTURE_DETAILS

Approx. size: RUPTURE_WIDTH, RUPTURE_LENGTH

☐ Overfill or Overflow

☐ Other ⇨ Describe: _____ RELEASE_TYPE_DETAILS

**PART D – ADDITIONAL CONSEQUENCE INFORMATION**

1. Wildlife impact: ○ Yes ○ No **WILDLIFE_IMPACT_IND**

1.a If Yes, specify all that apply:

☐ Fish/aquatic **FISH_AQUATIC_IMPACT_IND**

☐ Birds **BIRDS_IMPACT_IND**

☐ Terrestrial **TERRESTRIAL_IMPACT_IND**

*2. Soil contamination: ○ Yes ○ No **SOIL_CONTAMINATION**

3. Long term impact assessment performed or planned: ○ Yes ○ No **LONG_TERM_ASSESSMENT**

4. Anticipated remediation: ○ Yes ○ No (not needed) **REMEDIATION_IND**

4.a If Yes, specify all that apply:

☐ Surface water ☐ Groundwater ☐ Soil ☐ Vegetation ☐ Wildlife

**SURFACE_WATER_REMED_IND , GROUNDWATER_REMED_IND, SOIL_REMED_IND, VEGETATION_REMED_IND, WILDLIFE_REMED_IND**

*5. Water contamination: **WATER_CONTAM_IND** ○ Yes ⇨ *(Complete 5.a – 5.c below)* ○ No

*5.a Specify all that apply:

☐ Ocean/Seawater **OCEAN_SEAWATER_IND**

☐ Surface **SURFACE_CONTAM_IND**

☐ Groundwater **GROUNDWATER_CONTAM_IND**

☐ Drinking water ⇨ **DRINKING_WATER_CONTAM_IND**

○ Private Well **PRIVATE_WELL_CONTAM_IND** ○ Public Water Intake **PUBLIC_WATER_CONTAM_IND**

*5.b Estimated amount released in or reaching water: /___/___/___/./___/___/___/./___/___/ Barrels **AMOUNT_RELEASED**

*5.c Name of body of water, if commonly known: _____ **REL_WATER_NAME**

*6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program? ○ Yes ○ No **COULD_BE_HCA**

*7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)? **COMMODITY_REACHED_HCA**

7.a If Yes, specify HCA type(s): *(select all that apply)*

☐ Commercially Navigable Waterway **COMMERCIALLY_NAV_IND**
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
○ Yes ○ No **COMMERCIALLY_NAV_YES_NO**

☐ High Population Area **HIGH_POP_IND**
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
○ Yes ○ No **HIGH_POP_YES_NO**

☐ Other Populated Area **OTHER_POP_IND**
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
○ Yes ○ No **OTHER_POP_YES_NO**

☐ Unusually Sensitive Area (USA) – Drinking Water **USA_DRINKING_IND**
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
○ Yes ○ No **USA_DRINKING_YES_NO**

☐ Unusually Sensitive Area (USA) – Ecological **USA_ECOLOGICAL_IND**
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?
○ Yes ○ No **USA_ECOLOGICAL_YES_NO**

*8. Estimated cost to Operator:

8.a Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator $ /___/_____ **EST_COST_OPER_PAID**

8.b Estimated cost of commodity lost $ /___/___/___ **EST_COST_GAS_RELEASED**

8.c Estimated cost of Operator's property damage & repairs $ /___/___ **EST_COST_PROP_DAMAGE**

8.d Estimated cost of Operator's emergency response $ /___/___/___ **EST_COST_EMERGENCY**

8.e Estimated cost of Operator's environmental remediation $ /___/___/___ **EST_COST_ENVIRONMENTAL**

8.f Estimated other costs $ /___/___/___ **EST_COST_OTHER**

Describe _____ **EST_COST_OTHER_DETAILS**

8.g Estimated total costs (sum of above) $ /___/___/___ **PRPTY**

## PART E – ADDITIONAL OPERATING INFORMATION

*1. Estimated pressure at the point and time of the Accident (psig): /__/__/,/__/__/__/__/ ACCIDENT_PSIG

*2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig): /__/__/,/__/__/__/__/ MOP_PSIG

*3. Describe the pressure on the system or facility relating to the Accident: *(select only one)* ACCIDENT_PRESSURE

- ☐ Pressure did not exceed MOP
- ☐ Pressure exceeded MOP, but did not exceed 110% of MOP
- ☐ Pressure exceeded 110% of MOP

*4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?

- ☐ No PRESSURE_RESTRICTION_IND
- ☐ Yes ⇨ *(Complete 4.a and 4.b below)*

*4.a Did the pressure exceed this established pressure restriction? ○ Yes ○ No EXCEED_RETSTRICTION_IND

*4.b mandated by PHMSA or the State? PHMSA_RESTRICTION_IND ○ PHMSA ○ State ○ Not mandated

*5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?

- ☐ No PART_C_QUESTION_2_IND
- ☐ Yes ⇨ *(Complete 5.a – 5.f below)*

5.a Type of upstream valve used to initially isolate release source:
UPSTREAM_VALVE_TYPE_IND ○ Manual ○ Automatic ○ Remotely Controlled

5.b Type of downstream valve used to initially isolate release source:
DOWNSTREAM_VALVE_TYPE_IND ○ Manual ○ Automatic ○ Remotely Controlled ○ Check Valve

5.c Length of segment initially isolated between valves (ft): /__/__/__/,/__/__/__/__/ LENGTH_SEGMENT_ISOLATED

5.d Is the pipeline configured to accommodate internal inspection tools? INTERNAL_INSPECTION_IND

- ☐ Yes
- ☐ No ⇨ Which physical features limit tool accommodation? *(select all that apply)*
  - ○ Changes in line pipe diameter DIAMETER_CHANGE_IND
  - ○ Presence of unsuitable mainline valves UNSUITABLE_MAINLINE_IND
  - ○ Tight or mitered pipe bends TIGHT_MITERED_IND
  - ○ Other passage restrictions OTHER_RESTRICTIONS_IND
  - ○ Extra thick pipe wall EXTRA_THICK_WALL_IND
  - ○ Other OTHER_INSPECTION_IND Describe: INTERNAL_INSPECTION_DETAILS

5.e For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?

- ☐ No OPERATION_COMPLICATIONS_IND
- ☐ Yes ⇨ Which operational factors complicate execution? *(select all that apply)*
  - ○ Excessive debris or scale, wax, or other wall build-up EXCESSIVE_DEBRIS_IND
  - ○ Low operating pressure(s) LOW_OP_PRESSURE_IND
  - ○ Low flow or absence of flow LOW_FLOW_IND
  - ○ Incompatible commodity INCOMPAT_COMMOD_IND
  - ○ Other OTHER_COMPLICATIONS_IND ⇨ Describe INSPECT_COMP_DETAILS

5.f Function of pipeline system: *(select only one)* PIPELINE_FUNCTION

- ☐ > 20% SMYS Regulated Trunkline/Transmission
- ☐ ≤ 20% SMYS Regulated Trunkline/Transmission
- ☐ ≤ 20% SMYS "Unregulated" Trunkline/Transmission
- ☐ > 20% SMYS Regulated Gathering
- ☐ ≤ 20% SMYS Regulated Gathering
- ☐ ≤ 20% SMYS "Unregulated" Gathering

*6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?

☐ No SCADA_IN_PLACE_IND

☐ Yes ⇨ 6.a Was it operating at the time of the Accident? ○ Yes ○ No SCADA_OPERATING_IND

6.b Was it fully functional at the time of the Accident? ○ Yes ○ No SCADA_FUNCTIONAL_IND

6.c Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident? ○ Yes ○ No SCADA_DETECTION_IND

6.d Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident? ○ Yes ○ No SCADA_CONF_IND

*7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?

☐ No CPM_IN_PLACE_IND

☐ Yes ⇨ 7.a Was it operating at the time of the Accident? ○ Yes ○ No CPM_OPERATING_IND

7.b Was it fully functional at the time of the Accident? ○ Yes ○ No CPM_FUNCTIONAL_IND

7.c Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident? ○ Yes ○ No CPM_DETECTION_IND

7.d Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident? ○ Yes ○ No CPM_CONF_IND

*8. How was the Accident initially identified for the Operator? *(select only one)* ACCIDENT_IDENTIFIER

☐ CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
☐ Static Shut-in Test or Other Pressure or Leak Test
☐ Controller
☐ Air Patrol
☐ Notification from Public
☐ Local Operating Personnel, including contractors
☐ Ground Patrol by Operator or its contractor
☐ Notification from Emergency Responder
☐ Notification from Third Party that caused the Accident ☐ Other __ ACCIDENT_DETAILS

*8.a If "Controller", "Local Operating Personnel, including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 8, specify the following: *(select only one)* OPERATOR_TYPE

○ Operator employee ○ Contractor working for the Operator

*9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident? *(select only one)* INVESTIGATION_STATUS

☐ Yes, but the investigation of the control room and/or controller actions has not yet been completed by the Operator *(Supplemental Report required)*
☐ No, the facility was not monitored by a controller(s) at the time of the Accident
☐ No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the Operator did not investigate)* INVESTIGATION_STATUS_DETAILS

_____
_____
_____

☐ Yes, specify investigation result(s): *(select all that apply)*

○ Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator) and other factors associated with fatigue INVEST_SCHEDULE_IND

○ Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator) and other factors associated with fatigue *(provide an explanation for why not)* INVEST_NO_SCHEDULE_IND
INVEST_NO_SCHEDULE_IND_DETAILS

_____
_____
_____

○ Investigation identified no control room issues INVEST_NO_CONTROL_ROOM_IND
○ Investigation identified no controller issues INVEST_NO_CONTROLLER_IND
○ Investigation identified incorrect controller action or controller error INVEST_INCORRECT_ACTION_IND
○ Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response INVEST_FATIGUE_IND
Investigation identified incorrect procedures INVEST_INCORRECT_PROCEDURE_IND
○ Investigation identified incorrect control room equipment operation INVEST_INCORRECT_CONTROL_IND
○ Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response INVEST_MAINT_IND
○ Investigation identified areas other than those above INVEST_OTHER_IND
⇨ Describe: INVEST_OTHER_IND_DETAILS

_____
_____
_____

| PART F – DRUG & ALCOHOL TESTING INFORMATION | |
|---|---|

*1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations? **EMPLOYEE_DRUG_TEST_IND**

○ No

○ Yes ⇨ *1.a Specify how many were tested: /___/___/ **NUM_EMPLOYEES_TESTED**

*1.b Specify how many failed: /___/___/ **NUM_EMPLOYEES_FAILED**

*2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations? **CONTRACTOR_DRUG_TEST_IND**

○ No

○ Yes ⇨ *2.a Specify how many were tested: /___/___/ **NUM_CONTRACTORS_TESTED**

*2.b Specify how many failed: /___/___/ **NUM_CONTRACTORS_FAILED**

| PART G – APPARENT CAUSE<br>CAUSE, CAUSE_DETAIL(sub-cause) | ***Select only one box from PART G in the shaded column on the left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing, or root causes of the Accident in the narrative (PART H).*** |
|---|---|

## G1 - Corrosion Failure – *only one **sub-cause** can be picked from shaded left-hand column

INTERNAL_EXTERNAL

☐ **External Corrosion**

*1. Results of visual examination: VISUAL_EXAM_RESULTS
- ○ Localized Pitting ○ General Corrosion
- ○ Other _____ VISUAL_EXAM_DETAILS

*2. Type of corrosion: *(select all that apply)* GALVANIC_CORROSION_IND, ATMOSPHERE_CORROSION_IND, STRAY_CURRENT_CORROSION_IND, MICROBIOLOGICAL_CORROSION_IND, SELECTIVE_SEAM_CORROSION_IND, OTHER_CORROSION_IND, CORROSION_TYPE_DETAILS
- ○ Galvanic ○ Atmospheric ○ Stray Current ○ Microbiological ○ Selective Seam
- ○ Other _____

*3. The type(s) of corrosion selected in Question 2 is based on the following: FIELD_EXAM_BASIS_IND, METALLURGICAL_BASIS_IND, OTHER_BASIS_IND, CORROSION_BASIS_DETAILS
- ○ Field examination ○ Determined by metallurgical analysis
- ○ Other _____

*4. Was the failed item buried under the ground? UNDERGROUND_LOCATION
- ○ Yes ⇨ *4.a Was failed item considered to be under cathodic protection at the time of the Accident? UNDER_CATHODIC_PROTECTION_IND
  - ○ Yes ⇨ Year protection started: /___/___/___/___/ CATHODIC_PRO_START_YEAR
  - ○ No
  - *4.b Was shielding, tenting, or disbonding of coating evident at the point of the Accident? SHIELDING_EVIDENT
    - ○ Yes ○ No
  - *4.c Has one or more Cathodic Protection Survey been conducted at the point of the Accident? CATHODIC_SURVEY_TYPE (YES/NO)
    - ○ Yes,CP Annual Survey⇨Most recent year conducted: CP_ANNUAL_SURVEY_IND, CP_ANNUAL_SURVEY_YEAR
    - ○ Yes,Close Interval Survey⇨Most recent year conducted: CLOSE_INTERVAL_SURVEY_IND, CLOSE_INTERVAL_SURVEY_YEAR
    - ○ Yes, Other CP Survey ⇨ Most recent year conducted: OTHER_CP_SURVEY_IND, OTHER_CP_SURVEY_YEAR
    - ○ No CATHODIC_SURVEY_TYPE (No)
- ○ No ⇨ 4.d Was the failed item externally coated EXTERNALLY_COATED ○ Yes ○ No

*5. Was there observable damage to the coating or paint in the vicinity of the corrosion?
- ○ Yes ○ No PRIOR_DAMAGE

☐ **Internal Corrosion**

*6. Results of visual examination: INT_VISUAL_EXAM_RESULTS
- ○ Localized Pitting ○ General Corrosion ○ Not cut open
- ○ Other _____ INT_VISUAL_EXAM_DETAILS

*7. Cause of corrosion: INT_CORROSIVE_COMMODITY_IND, INT_WATER_ACID_IND, INT_MICROBIOLOGICAL_IND, INT_EROSION_IND, INT_OTHER_CORROSION_IND,
- ○ Corrosive Commodity ○ Water drop-out/Acid ○ Microbiological ○ Erosion
- ○ Other ___ INT_CORROSION_TYPE_DETAILS

*8. The cause(s) of corrosion selected in Question 7 is based on the following: INT_FIELD_EXAM_BASIS_IND, INT_METALLURGICAL_BASIS_IND, INT_OTHER_BASIS_IND ○ Field examination ○ Determined by metallurgical analysis ○ Other INT_CORROSION_BASIS_DETAILS

*9. Location of corrosion: INT_LOW_POINT_PIPE_LOC_IND, INT_ELBOW_LOC_IND, INT_OTHER_LOC_IND
- ○ Low point in pipe ○ Elbow ○ Other__ CORROSION_LOCATION_DETAILS

*10. Was commodity treated corrosion inhibitors ○ Yes ○ No CORROSION_INHIBITORS

11. Was the interior lined with protective coating? ○ Yes ○ No CORROSION_LINING

12. Were cleaning/dewatering pigs (or other operations) routinely utilized?
- ○ Not applicable - Not mainline pipe ○ Yes ○ No CLEANING_DEWATERING

13. Were corrosion coupons routinely utilized? CORROSION_COUPONS
- ○ Not applicable - Not mainline pipe ○ Yes ○ No

**Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.**

14. List the year of the most recent inspections: API_STD_OUT_OF_SERVICE_IND

14.a API Std 653 Out-of-Service Inspection /___/___/___/___/ API_STD_OUT_OF_SERVICE_YEAR

○ No Out-of-Service Inspection completed API_STD_IN_SERVICE_IND

14.b API Std 653 In-Service Inspection /___/___/___/___/ API_STD_IN_SERVICE_YEAR

☐ No In-Service Inspection completed

**Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.**

15. Has one or more internal inspection tool collected data at the point of the Accident? COR_INSP_TOOL_COLL_IND

○ Yes ☐ No

15.a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

| | | |
|---|---|---|
| ○ Magnetic Flux Leakage Tool | /___/___/___/___/ | COR_MAGNETIC_FLUX_LEAKAGE_IND , _YEAR |
| ☐ Ultrasonic | /___/___/___/___/ | COR_ULTRASONIC_IND , _YEAR |
| ☐ Geometry | /___/___/___/___/ | COR_GEOMETRY_IND , _YEAR |
| ☐ Caliper | /___/___/___/___/ | COR_CALIPER_IND , _YEAR |
| ☐ Crack | /___/___/___/___/ | COR_CRACK_IND , _YEAR |
| ☐ Hard Spot | /___/___/___/___/ | COR_HARDSPOT_IND , _YEAR |
| ☐ Combination Tool | /___/___/___/___/ | COR_COMBINATION_TOOL_IND , _YEAR |
| ☐ Transverse Field/Triaxial | /___/___/___/___/ | COR_TRANSVERSE_FIELD_IND , _YEAR |
| ☐ Other _____ | /___/___/___/___/ | COR_INSPECTION_OTHER_IND , _YEAR , _DETAILS |

16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?

○ Yes ⇨ Most recent year tested: /___/___/___/___/ Test pressure (psig): /___/___/___/___/___/

☐ No COR_HYDROTEST_CONDUCTED_IND, COR_HYDROTEST_CONDUCTED_YEAR, COR_HYDROTEST_PRESSURE

17. Has one or more Direct Assessment been conducted on this segment? DIRECT_INSPECTION_TYPE

○ Yes, and an investigative dig was conducted ⇨ Most recent year conducted: /___/___/___/___/ DIRECT_YES_DIG_YEAR

☐ Yes, but the point of the Accident was not identified ⇨ Most recent year conducted: /___/___/___ DIRECT_YES_NO_DIG_YEAR

○ No

18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?

○ Yes ☐ No COR_NON_DESTRUCTIVE_IND

18.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:

| | | |
|---|---|---|
| ○ Radiography | /___/___/___/___/ | COR_RADIOGRAPHY_IND , _YEAR |
| ☐ Guided Wave Ultrasonic | /___/___/___/___/ | COR_GUIDED_WAVE_IND , _YEAR |
| ☐ Handheld Ultrasonic Tool | /___/___/___/___/ | COR_HANDHELD_ULTRA_IND , _YEAR |
| ☐ Wet Magnetic Particle Test | /___/___/___/___/ | COR_WET_MAGNETIC_IND , _YEAR |
| ☐ Dry Magnetic Particle Test | /___/___/___/___/ | COR_DRY_MAGNETIC_IND , _YEAR |
| ☐ Other _____ | /___/___/___/___/ | COR_NON_DEST_OTHER_IND , _YEAR , _DETAILS |

## G2- Natural Force Damage - *only one **sub-cause** can be picked from shaded left-hand column

| NATURAL_FORCE_TYPE | |
|---|---|
| ☐ **Earth Movement, NOT due to Heavy Rains/Floods** | EARTH_SUBTYPE<br>1. Specify: ○ Earthquake ☐ Subsidence ☐ Landslide<br>○ Other _____ NF_OTHER_DETAILS |
| ☐ **Heavy Rains/Floods** | HEAVY_RAINS_SUBTYPE<br>2. Specify: ○ Washout/Scouring ○ Flotation ○ Mudslide<br>○ Other ___ NF_OTHER_DETAILS |
| ☐ **Lightning** | LIGHTNING_SUBTYPE<br>3. Specify: ○ Direct hit ☐ Secondary impact such as resulting nearby fires |
| ☐ **Temperature** | TEMPERATURE_SUBTYPE<br>4. Specify: ○ Thermal Stress ☐ Frost Heave<br>○ Frozen Components ○ Other _____ NF_OTHER_DETAILS |
| ☐ **High Winds** | |
| ☐ **Other Natural Force Damage** | *5. Describe: _____ NF_OTHER_DETAILS |

**Complete the following if any Natural Force Damage sub-cause is selected.** NF_EXTREME_WEATHER_IND

*6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event? ○ Yes ○ No

NF_HURRICANE_IND, NF_TROPICAL_STORM_IND, NF_TORNADO_IND, NF_OTHER_IND

*6.a If Yes, specify: (*select all that apply*) ○ Hurricane ○ Tropical Storm ○ Tornado ○ Other _____ NF_EXTREME_WEATHER_DETAILS

## G3 – Excavation Damage - *only one **sub-cause** can be picked from shaded left-hand column

PARTY_TYPE

☐ **Excavation Damage by Operator (First Party)**

☐ **Excavation Damage by Operator's Contractor (Second Party)**

☐ **Excavation Damage by Third Party**

☐ **Previous Damage due to Excavation Activity**

**Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.**

1. Has one or more internal inspection tool collected data at the point of the Accident?
○ Yes ○ No EX_NSPECT_TOOL_COLLECTED_IND

1.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

- ○ Magnetic Flux Leakage — EX_MAGNETIC_FLUX_LEAKAGE_IND , _YEAR
- ○ Ultrasonic — EX_ULTRASONIC_IND , _YEAR
- ○ Geometry — EX_GEOMETRY_IND , _YEAR
- ○ Caliper — EX_CALIPER_IND , _YEAR
- ○ Crack — EX_CRACK_IND , _YEAR
- ○ Hard Spot — EX_HARDSPOT_IND , _YEAR
- ○ Combination Tool — EX_COMBINATION_TOOL_IND , _YEAR
- ○ Transverse Field/Triaxial — EX_TRANSVERSE_FIELD_IND , _YEAR
- ○ Other _____ — EX_INSPECTION_OTHER_IND , _YEAR , _DETAILS

2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained? ○ Yes ○ No EX_BEFORE_DAMAGE

3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident? EX_HYDROTEST_CONDUCTED_IND

○ Yes ⇨ Most recent year tested: /__/__/__/__/ EX_HYDROTEST_CONDUCTED_YEAR
Test pressure (psig): /__/__/__/__/__/__/ EX_HYDROTEST_PRESSURE

○ No

4. Direct Assessment conducted ? EX_DIRECT_ASSESSMENT_TYPE

○ Yes, and an investigative dig was conducted at the point of the Accident
⇨ year conducted: /__/__/__/__/__/__/ EX_DIRECT_YES_DIG_YEAR

○ Yes, but the point of the Accident was not identified as a dig site
⇨ year conducted: /__/__/__/__/__/__/ EX_DIRECT_YES_NO_DIG_YEAR

○ No

5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002? EX_NON_DESTRUCTIVE_IND
○ Yes ○ No

5.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:

- ○ Radiography — EX_RADIOGRAPHY_IND, _YEAR
- ○ Guided Wave Ultrasonic — EX_GUIDED_WAVE_IND, _YEAR
- ○ Handheld Ultrasonic Tool — EX_HANDHELD_ULTRA_IND , _YEAR
- ○ Wet Magnetic Particle Test — EX_WET_MAGNETIC_IND, _YEAR
- ○ Dry Magnetic Particle Test — EX_DRY_MAGNETIC_IND , _YEAR
- ○ Other _____ — EX_NON_DEST_OTHER_IND , _YEAR , _DETAILS

**Complete the following if Excavation Damage by Third Party is selected as the sub-cause.**

6. Did the Operator get prior notification of the excavation activity? ○ Yes ○ No PRIOR_NOTIFICATION_IND

*6.a If Yes, Notification received from: *(select all that apply)* ○ One-Call System ○ Excavator ○ Contractor ○ Landowner
ONE_CALL_SYSTEM_IND, EXCAVATOR_IND, CONTRACTOR_IND, LANDOWNER_IND

**Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.**

7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)? ○Yes ○ No **NOTIFY_CGA_DIRT**

*8. Right-of-Way where event occurred: *(select all that apply)*

☐ Public **PUBLIC_ROW_IND, PUBLIC_SUBTYPE**

⇨ Specify: ○ City Street ○ State Highway ○County Road ○ Interstate Highway ○ Other

☐ Private **PRIVATE_ROW_IND, PRIVATE_SUBTYPE**

⇨ Specify: ○ Private Landowner ○ Private Business ○ Private Easement

☐ Pipeline Property/Easement **PIPELINE_EASEMENT_ROW_IND**

☐ Power/Transmission Line **POWER_TRANSMISSION_ROW_IND**

☐ Railroad **RAILROAD_ROW_IND**

☐ Dedicated Public Utility Easement **PUBLIC_UTIL_EASEMENT_ROW_IND**

☐ Federal Land **FEDERAL_LAND_ROW_IND**

☐ Data not collected **DATA_NOT_COLLECTED_ROW_IND**

☐ Unknown/Other **UNKNOWN_ROW_IND**

*9. Type of excavator: *(select only one)* **EXCAVATOR_TYPE**

○ Contractor ○ County ○ Developer ○ Farmer ○ Municipality ○ Occupant
○ Railroad ○ State ○ Utility ○ Data not collected ○ Unknown/Other

*10. Type of excavation equipment: *(select only one)* **EXCAVATOR_EQUIPMENT**

○ Auger ○ Backhoe/Trackhoe ○ Boring ○ Drilling ○Directional Drilling
○ Explosives ○ Farm Equipment ○ Grader/Scraper ○ Hand Tools ○ Milling Equipment
○ Probing Device ○ Trencher ○ Vacuum Equipment ○ Data not collected ○ Unknown/Other

*11. Type of work performed: *(select only one)* **WORK_PERFORMED**

○Agriculture ○ Cable TV ○ Curb/Sidewalk ○ Building Construction ○ Building Demolition
○ Drainage ○ Driveway ○ Electric ○ Engineering/Surveying ○ Fencing
○ Grading ○ Irrigation ○ Landscaping ○ Liquid Pipeline ○ Milling
○ Natural Gas ○ Pole ○ Public Transit Authority ○ Railroad Maintenance ○ Road Work
○ Sewer (Sanitary/Storm) ○ Site Development ○ Steam ○ Storm Drain/Culvert ○Street Light
○ Telecommunications ○Traffic Signal ○ Traffic Sign ○ Water ○ Waterway Improvement
○ Data not collected ○ Unknown/Other

*12. Was the One-Call Center notified? ○ Yes ○ No **ONE_CALL_NOTIFIED_IND**

*12.a If Yes, specify ticket number: /__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/__/ **ONE_CALL_TICKET_NUM**

*12.b If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified: _____ **ONE_CALL_CENTER_NAME**

*13. Type of Locator: **LOCATOR_TYPE** ○ Utility Owner ○ Contract Locator ○ Data not collected ○ Unknown/Other

*14. Were facility locate marks visible? **VISIBLE_MARKS** ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*15. Were facilities marked correctly? **FACILITIES_MARKED** ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*16. interruption in service? **SERVICE_INTERRUPTION** ○ No ○ Yes ○ Data not collected ○ Unknown/Other

*16.a If Yes, specify duration of the interruption: /___/___/___/___/ hours **SERVICE_INTERRUPTION_HOURS**

*(This CGA-DIRT section continued on next page with Question 17.)*

*17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well)*: **ROOT_CAUSE**

☐ One-Call Notification Practices Not Sufficient: *(select only one)* **ONE_CALL_SUBTYPE**

- ○ No notification made to the One-Call Center
- ○ Notification to One-Call Center made, but not sufficient
- ○ Wrong information provided

☐ Locating Practices Not Sufficient: *(select only one)* **LOCATING_SUBTYPE**

- ○ Facility could not be found/located
- ○ Facility marking or location not sufficient
- ○ Facility was not located or marked
- ○ Incorrect facility records/maps

☐ Excavation Practices Not Sufficient: *(select only one)* **EXCAVATION_SUBTYPE**

- ○ Excavation practices not sufficient (other)
- ○ Failure to maintain clearance
- ○ Failure to maintain the marks
- ○ Failure to support exposed facilities
- ○ Failure to use hand tools where required
- ○ Failure to verify location by test-hole (pot-holing)
- ○ Improper backfilling

☐ One-Call Notification Center Error

☐ Abandoned Facility

☐ Deteriorated Facility

☐ Previous Damage

☐ Data Not Collected

☐ Other / None of the Above *(explain)*_____ **ROOT_CAUSE_OTHER**

_____
_____
_____

## G4 - Other Outside Force Damage - *only one **sub-cause** can be picked from shaded left-hand column

OUTSIDE_FORCE_TYPE

☐ **Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Accident**

☐ **Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation**

1. Vehicle/Equipment operated by: *(select only one)* VEHICLE_SUBTYPE
   ○ Operator ○ Operator's Contractor ○ Third Party

☐ **Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring**

2. Select one or more of the following IF an extreme weather event was a factor:
   OSF_HURRICANE_IND, OSF_TROPICAL_STORM_IND, OSF_TORNADO_IND, OSF_OTHER_WEATHER_IND
   ○ Hurricane ○ Tropical Storm ○ Tornado
   ○ Heavy Rains/Flood ○ Other _____ OSF_OTHER_WEATHER_DETAILS

☐ **Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation**

☐ **Electrical Arcing from Other Equipment or Facility**

☐ **Previous Mechanical Damage NOT Related to Excavation**

**Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.**

3. Has one or more internal inspection tool collected data at the point of the Accident?
   ○ Yes ○ No OSF_INSPECTION_TOOL_COLLECTED_IND

3.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

- ○ Magnetic Flux Leakage OSF_MAGNETIC_FLUX_LEAKAGE_IND , _YEAR
- ○ Ultrasonic OSF_ULTRASONIC_IND , _YEAR
- ○ Geometry OSF_GEOMETRY_IND , _YEAR
- ○ Caliper OSF_CALIPER_IND , _YEAR
- ○ Crack OSF_CRACK_IND , _YEAR
- ○ Hard Spot OSF_HARDSPOT_IND , _YEAR
- ○ Combination Tool OSF_COMBINATION_TOOL_IND , _YEAR
- ○ Transverse Field/Triaxial OSF_TRANSVERSE_FIELD_IND , _YEAR
- ○ Other _____ OSF_INSPECTION_OTHER_IND , _YEAR , _DETAILS

4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained? ○ Yes ○ No OSF_BEFORE_DAMAGE

5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident? HYDROTEST_CONDUCTED_IND

   ○ Yes ⇨ year tested: /___/___/___/___/ OSF_HYDROTEST_CONDUCTED_YEAR
   Test pressure (psig): /___/___/, /___/___/ OSF_HYDROTEST_PRESSURE
   ○ No

6. Has one or more Direct Assessment been conducted on the pipeline segment?
   OSF_DIRECT_INSPECTION_TYPE

   ○ Yes, and an investigative dig was conducted at the point of the Accident
   ⇨ year conducted: /___/___/___/___/OSF_DIRECT_YES_DIG_YEAR
   ○ Yes, but the point of the Accident was not identified as a dig site
   ⇨ year conducted: /___/___/___/___/ OSF_DIRECT_YES_NO_DIG_YEAR
   ○ No

*(This section continued on next page with Question 7.)*

| | |
|---|---|
| | 7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002? **OSF_NON_DESTRUCTIVE_IND**<br>○ Yes ○ No<br>7.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:<br>○ Radiography **OSF_RADIOGRAPHY_IND , _YEAR**<br>○ Guided Wave Ultrasonic **OSF_GUIDED_WAVE_IND , _YEAR**<br>○ Handheld Ultrasonic Tool **OSF_HANDHELD_ULTRA_IND , _YEAR**<br>○ Wet Magnetic Particle Test **OSF_WET_MAGNETIC_IND , _YEAR**<br>○ Dry Magnetic Particle Test **OSF_DRY_MAGNETIC_IND , _YEAR**<br>○ Other _____ **OSF_NON_DEST_OTHER_IND , _YEAR , _DETAILS** |
| ☐ **Intentional Damage** | 8. Specify: **INTENTIONAL_SUBTYPE**<br>○ Vandalism ○ Terrorism<br>○ Theft of transported commodity ○ Theft of equipment<br>○ Other _____ **INTENTIONAL_DETAILS** |
| ☐ **Other Outside Force Damage** | *9. Describe: _____ **OSF_OTHER_DETAILS** |

## G5 - Material Failure of Pipe or Weld

1. The sub-cause selected below is based on the following: FIELD_EXAM_IND, METALLURGICAL_IND, OTHER_ANALYSIS_IND, OTHER_ANALYSIS_DETAILS, STILL_UNDER_INVEST_IND ☐ Field Examination ☐ Determined by Metallurgical Analysis ☐ Other Analysis_____ ☐ Sub-cause is Tentative or Suspected; Still Under Investigation *(Supplemental Report required)*

FAILURE_TYPE

☐ **Construction-, Installation-, or Fabrication-related**

2. List contributing factors: *(select all that apply)*
- ☐ Fatigue- or Vibration-related: FATIGUE_VIBR_RELATED_1, FAILURE_SUBTYPE_1
  - ○ Mechanically-induced prior to installation (such as during transport of pipe)
  - ○ Mechanical Vibration
  - ○ Pressure-related
  - ○ Thermal
  - ○ Other _____ FATIGUE_VIBR_RELATED_OTHER_1
- ☐ Mechanical Stress MECHANICAL_STRESS_1
- ☐ Other OTHER_FACTOR_1 _____ OTHER_FACTOR_DETAILS_1

☐ **Original Manufacturing-related (NOT girth weld or other welds formed in the field)**

2. List contributing factors: *(select all that apply)*
- ☐ Fatigue- or Vibration-related: FATIGUE_VIBR_RELATED_2, FAILURE_SUBTYPE_2
  - ○ Mechanically-induced prior to installation (such as during transport of pipe)
  - ○ Mechanical Vibration
  - ○ Pressure-related
  - ○ Thermal
  - ○ Other _____ FATIGUE_VIBR_RELATED_OTHER_2
- ☐ Mechanical Stress MECHANICAL_STRESS_2
- ☐ Other OTHER_FACTOR_2 _____ OTHER_FACTOR_DETAILS_2

☐ **Environmental Cracking-related**

STRESS_SUBTYPE 3. Specify: ○ Stress Corrosion Cracking ○ Sulfide Stress Cracking ○ Hydrogen Stress Cracking ○ Other _____STRESS_DETAILS

**Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.**

*4. Additional factors: *(select all that apply)* ○ Dent ○ Gouge ○ Pipe Bend ○ Arc Burn ○ Crack ○ Lack of Fusion ○ Lamination ○ Buckle ○ Wrinkle ○ Misalignment ○ Burnt Steel ○ Other _____
ADDITIONAL_DENT_IND, ADDITIONAL_GOUGE_IND, ADDITIONAL_PIPE_BEND_IND, ADDITIONAL_ARC_BURN_IND, ADDITIONAL_CRACK_IND, ADDITIONAL_LACK_FUSION_IND, ADDITIONAL_LAMINATION_IND, ADDITIONAL_BUCKLE_IND, ADDITIONAL_WRINKLE_IND, PWF_ADDL_MISALIGNMENT_IND, ADDITIONAL_BURNT_STEEL_IND, PWF_ADDITIONAL_OTHER_IND, PWF_ADDITIONAL_OTHER_DETAILS

*5. Has one or more internal inspection tool collected data PWF_INSPECTION_TOOL_COLLECTED_IND

*5.a If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:

- ○ Magnetic Flux Leakage PWF_MAGNETIC_FLUX_LEAKAGE_IND , _YEAR
- ○ Ultrasonic PWF_ULTRASONIC_IND, _YEAR
- ○ Geometry PWF_GEOMETRY_IND, _YEAR
- ○ Caliper PWF_CALIPER_IND , _YEAR
- ○ Crack PWF_CRACK_IND , _YEAR
- ○ Hard Spot PWF_HARDSPOT_IND , _YEAR
- ○ Combination Tool PWF_COMBINATION_TOOL_IND , _YEAR
- ○ Transverse Field/Triaxial PWF_TRANSVERSE_FIELD_IND , _YEAR
- ○ Other _____ PWF_INSPECTION_OTHER_IND , _YEAR, _DETAILS

*6. Has one or more hydrotest or other pressure test been conducted PWF_HYDROTEST_CONDUCTED_IND

- ○ Yes ⇨ Most recent year tested: /___/___/___/___/ Test pressure (psig): /___/___/,/___/___/___/
- ○ No PWF_HYDROTEST_CONDUCTED_YEAR PWF_HYDROTEST_PRESSURE

*7. Has one or more Direct Assessment been conducted on the pipeline segment? PWF_DIRECT_INSPECTION_TYPE

- ○ Yes, and an investigative dig was conducted ⇨ Most recent year conducted: /___/___/___/___/PWF_DIRECT_YES_DIG_YEAR
- ○ Yes, but the point of the Accident was not identified ⇨ year conducted: /___/___/___/___/PWF_DIRECT_YES_NO_DIG_YEAR
- ○ No

*8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?

○ Yes ○ No PWF_NON_DESTRUCTIVE_IND

*8.a If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:

- ○ Radiography PWF_RADIOGRAPHY_IND, _YEAR
- ○ Guided Wave Ultrasonic PWF_GUIDED_WAVE_IND , _YEAR
- ○ Handheld Ultrasonic Tool PWF_HANDHELD_ULTRA_IND , _YEAR
- ○ Wet Magnetic Particle Test PWF_WET_MAGNETIC_IND , _YEAR
- ○ Dry Magnetic Particle Test PWF_DRY_MAGNETIC_IND , _YEAR
- ○ Other _____ PWF_NON_DEST_OTHER_IND , _YEAR , _DETAILS

## G6 - Equipment Failure - *only one **sub-cause** can be picked from shaded left-hand column

| | |
|---|---|
| EQ_FAILURE_TYPE<br>☐ **Malfunction of Control/Relief Equipment** | 1. Specify: *(select all that apply)*<br>○ Control Valve ○ Instrumentation ○ SCADA<br>○ Communications ○ Block Valve ○ Check Valve<br>○ Relief Valve ○ Power Failure ○ Stopple/Control Fitting<br>○ ESD System Failure ○ Other<br>CONTROL_VALVE_IND, INSTRUMENTATION_IND, SCADA_IND, COMMUNICATIONS_IND, BLOCK_VALVE_IND, CHECK_VALVE_IND, RELIEF_VALVE_IND, POWER_FAILURE_IND, STOPPLE_CONTROL_FITTING_IND, ESD_SYSTEM_FAILURE_IND, OTHER_CONTROL_RELIEF_IND,OTHER_CONTROL_RELIEF_DETAILS |
| ☐ **Pump or Pump-related Equipment** | 2. Specify: OTHER_PUMP_IND<br>○ Seal/Packing Failure ○ Body Failure ○ Crack in Body<br>○ Appurtenance Failure ○ Other _____ OTHER_PUMP_DETAILS |
| ☐ **Threaded Connection/Coupling Failure** | 3. Specify: OTHER_STRIPPED_IND<br>○ Pipe Nipple ○ Valve Threads ○ Mechanical Coupling ○ Threaded Pipe Collar<br>○ Threaded Fitting ○ Other _____ OTHER_STRIPPED_DETAILS |
| ☐ **Non-threaded Connection Failure** | 4. Specify: OTHER_NON_THREADED_IND<br>○ O-Ring ○ Gasket ○ Seal or Packing<br>○ Other _____OTHER_NON_THREADED_DETAILS |
| ☐ **Defective or Loose Tubing or Fitting** | |
| ☐ **Failure of Equipment Body (except Pump), Tank Plate, or other Material** | |
| ☐ **Other Equipment Failure** | *5. Describe: _____ FAILURE_DETAILS<br>_____ |

**Complete the following if any Equipment Failure sub-cause is selected.**

*6. Additional factors that contributed to the equipment failure: *(select all that apply)*

- ○ Excessive vibration ADDITIONAL_VIBRATION_IND
- ○ Overpressurization ADDITIONAL_OVERPRESSURE_IND
- ○ No support or loss of support ADDITIONAL_SUPPORT_IND
- ○ Manufacturing defect ADDITIONAL_DEFECT_IND
- ○ Loss of electricity ADDITIONAL_ELECTRICITY_IND
- ○ Improper installation ADDITIONAL_INSTALLATION_IND
- ○ Mismatched items (different manufacturer for tubing and tubing fittings) ADDITIONAL_MISMATCH_IND
- ○ Dissimilar metals ADDITIONAL_DISSIMILAR_IND
- ○ Breakdown of soft goods due to compatibility issues with transported commodity ADDITIONAL_BREAKDOWN_IND
- ○ Valve vault or valve can contributed to the release ADDITIONAL_VALVE_IND
- ○ Alarm/status failure ADDITIONAL_ALARM_IND
- ○ Misalignment ADDITIONAL_MISALIGNMENT_IND
- ○ Thermal stress ADDITIONAL_THERMAL_IND
- ○ Other EQ_DDITIONAL_OTHER_IND _____ EQ_ADDITIONAL_OTHER_DETAILS

## G7 - Incorrect Operation - *only one **sub-cause** can be picked from shaded left-hand column

| OPERATION_TYPE | |
|---|---|
| ☐ **Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage** | |
| ☐ **Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow** | 1. Specify: OVERFLOW_OTHER_IND<br>○ Valve misalignment ○ Incorrect reference data/calculation<br>○ Miscommunication ○ Inad monitoring ○ Other ____OVERFLOW_OTHER_DETAILS |
| ☐ **Valve Left or Placed in Wrong Position, but NOT Resulting in a Tank, Vessel, or Sump/Separator Overflow or Facility Overpressure** | |
| ☐ **Pipeline or Equipment Overpressured** | |
| ☐ **Equipment Not Installed Properly** | |
| ☐ **Wrong Equipment Specified or Installed** | |
| ☐ **Other Incorrect Operation** | *2. Describe: _____ OPERATION_DETAILS |

**Complete the following if any Incorrect Operation sub-cause is selected.**

*3. Was this Accident related to: *(select all that apply)*
- ○ Inadequate procedure RELATED_INADEQUATE_PROC_IND
- ○ No procedure established RELATED_NO_PROC_IND
- ○ Failure to follow procedure RELATED_FAILURE_FOLLOW_IND
- ○ Other: RELATED_OTHER_IND _____ OPERATION_RELATED_DETAILS

*4. What category type was the activity that caused the Accident: CATEGORY_TYPE
- ○ Construction
- ○ Commissioning
- ○ Decommissioning
- ○ Right-of-Way activities
- ○ Routine maintenance
- ○ Other maintenance
- ○ Normal operating conditions
- ○ Non-routine operating conditions (abnormal operations or emergencies)

*5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?
OPERATOR_QUALIFICATION_IND ○ Yes ○ No

*5.a If Yes, were the individuals performing the task(s) qualified for the task(s)? QUALIFIED_INDIVIDUALS
- ○ Yes, they were qualified for the task(s)
- ○ No, but they were performing the task(s) under the direction and observation of a qualified individual
- ○ No, they were not qualified for the task(s) nor were they performing the task(s) under the direction and observation of a qualified individual

## G8 – Other Accident Cause - *only one **sub-cause** can be picked from shaded left-hand column

| OTHER_TYPE | |
|---|---|
| ☐ **Miscellaneous** | *1. Describe: _____ MISC_DETAILS<br>_____ |
| ☐ **Unknown** | UNKNOWN_SUBTYPE<br>2. Specify: ○ Investigation complete, cause of Accident unknown<br>○ Still under investigation, cause of Accident to be determined*<br>*(*Supplemental Report required)* |

**PART H – NARRATIVE DESCRIPTION OF THE ACCIDENT** *(Attach additional sheets as necessary)*

***PART I – PREPARER AND AUTHORIZED SIGNATURE**

*Preparer's Name (type or print)

Preparer's Title (type or print)

Preparer's E-mail Address

Preparer's Telephone Number

Preparer's Facsimile Number

Authorized Signature

*Date

Authorized Signature Telephone Number

*Authorized Signature's Name (type or print)

Authorized Signature's E-mail Address

Authorized Signature's Title (type or print)