49
Parts 186 to 199
Revised as of October 1, 2001

Transportation

Containing a codification of documents of general applicability and future effect

As of October 1, 2001

With Ancillaries

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A Special Edition of the Federal Register
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Cite this Code: CFR

To cite the regulations in this volume use title, part and section number. Thus, 49 CFR 190.1 refers to title 49, part 190, section 1.
Explanation

The Code of Federal Regulations is a codification of the general and permanent rules published in the Federal Register by the Executive departments and agencies of the Federal Government. The Code is divided into 50 titles which represent broad areas subject to Federal regulation. Each title is divided into chapters which usually bear the name of the issuing agency. Each chapter is further subdivided into parts covering specific regulatory areas.

Each volume of the Code is revised at least once each calendar year and issued on a quarterly basis approximately as follows:

- Title 1 through Title 16.................................as of January 1
- Title 17 through Title 27.................................as of April 1
- Title 28 through Title 41.................................as of July 1
- Title 42 through Title 50.................................as of October 1

The appropriate revision date is printed on the cover of each volume.

LEGAL STATUS

The contents of the Federal Register are required to be judicially noticed (44 U.S.C. 1507). The Code of Federal Regulations is prima facie evidence of the text of the original documents (44 U.S.C. 1510).

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To determine whether a Code volume has been amended since its revision date (in this case, October 1, 2001), consult the “List of CFR Sections Affected (LSA),” which is issued monthly, and the “Cumulative List of Parts Affected,” which appears in the Reader Aids section of the daily Federal Register. These two lists will identify the Federal Register page number of the latest amendment of any given rule.

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The Paperwork Reduction Act of 1980 (Pub. L. 96-511) requires Federal agencies to display an OMB control number with their information collection request.
Many agencies have begun publishing numerous OMB control numbers as amendments to existing regulations in the CFR. These OMB numbers are placed as close as possible to the applicable recordkeeping or reporting requirements.

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INCORPORATION BY REFERENCE

What is incorporation by reference? Incorporation by reference was established by statute and allows Federal agencies to meet the requirement to publish regulations in the Federal Register by referring to materials already published elsewhere. For an incorporation to be valid, the Director of the Federal Register must approve it. The legal effect of incorporation by reference is that the material is treated as if it were published in full in the Federal Register (5 U.S.C. 552(a)). This material, like any other properly issued regulation, has the force of law.

What is a proper incorporation by reference? The Director of the Federal Register will approve an incorporation by reference only when the requirements of 1 CFR part 51 are met. Some of the elements on which approval is based are:

(a) The incorporation will substantially reduce the volume of material published in the Federal Register.

(b) The matter incorporated is in fact available to the extent necessary to afford fairness and uniformity in the administrative process.

(c) The incorporating document is drafted and submitted for publication in accordance with 1 CFR part 51.

Properly approved incorporations by reference in this volume are listed in the Finding Aids at the end of this volume.

What if the material incorporated by reference cannot be found? If you have any problem locating or obtaining a copy of material listed in the Finding Aids of this volume as an approved incorporation by reference, please contact the agency that issued the regulation containing that incorporation. If, after contacting the agency, you find the material is not available, please notify the Director of the Federal Register, National Archives and Records Administration, Washington DC 20408, or call (202) 533–4534.

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A subject index to the Code of Federal Regulations is contained in a separate volume, revised annually as of January 1, entitled CFR INDEX AND FINDING AIDS. This volume contains the Parallel Table of Statutory Authorities and Agency Rules (Table I). A list of CFR titles, chapters, and parts and an alphabetical list of agencies publishing in the CFR are also included in this volume.

An index to the text of “Title 3—The President” is carried within that volume.

The Federal Register Index is issued monthly in cumulative form. This index is based on a consolidation of the “Contents” entries in the daily Federal Register.

A List of CFR Sections Affected (LSA) is published monthly, keyed to the revision dates of the 50 CFR titles.
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There are no restrictions on the republication of material appearing in the Code of Federal Regulations.

INQUIRIES

For a legal interpretation or explanation of any regulation in this volume, contact the issuing agency. The issuing agency’s name appears at the top of odd-numbered pages.

For inquiries concerning CFR reference assistance, call 202-523-5227 or write to the Director, Office of the Federal Register, National Archives and Records Administration, Washington, DC 20408 or e-mail info@fedreg.nara.gov.

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RAYMOND A. MOSLEY,
Director,
Office of the Federal Register.

October 1, 2001.
THIS TITLE

Title 49—TRANSPORTATION is composed of seven volumes. The parts in these volumes are arranged in the following order: Parts 1–99, parts 100–185, parts 186–199, parts 200–399, parts 400–999, parts 1000–1199, part 1200 to End. The first volume (parts 1–99) contains current regulations issued under subtitle A—Office of the Secretary of Transportation; the second volume (parts 100–185) and the third volume (parts 186–199) contain the current regulations issued under chapter I—Research and Special Programs Administration (DOT); the fourth volume (parts 200–399) contains the current regulations issued under chapter II—Federal Railroad Administration (DOT), and chapter III—Federal Motor Carrier Safety Administration (DOT); the fifth volume (parts 400–999) contains the current regulations issued under chapter IV—Coast Guard (DOT), chapter V—National Highway Traffic Safety Administration (DOT), chapter VI—Federal Transit Administration (DOT), chapter VII—National Railroad Passenger Corporation (AMTRAK), and chapter VIII—National Transportation Safety Board; the sixth volume (parts 1000–1199) contains the current regulations issued under chapter X—Surface Transportation Board and the seventh volume (part 1200 to End) contains the current regulations issued under chapter X—Surface Transportation Board and chapter XI—Bureau of Transportation Statistics, Department of Transportation. The contents of these volumes represent all current regulations codified under this title of the CFR as of October 1, 2001.

In the volume containing parts 100–185, see §172.101 for the Hazardous Materials Table. The Federal Motor Vehicle Safety Standards appear in part 571.

Redesignation tables for chapter X—Surface Transportation Board, Department of Transportation appear in the Finding Aids section of the sixth and seventh volumes.
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Editorial Note: Other regulations issued by the Department of Transportation appear in 14 CFR chapters I and II, 23 CFR, 33 CFR chapters I and IV, 44 CFR chapter IV, 46 CFR chapters I through III, 48 CFR chapter 12, and 49 CFR chapters I through VI.

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SUBCHAPTER D—PIPELINE SAFETY

PART 190—PIPELINE SAFETY PROGRAMS AND RULEMAKING PROCEDURES

Subpart A—General

§ 190.1 Purpose and scope.
(a) This part prescribes procedures used by the Research and Special Programs Administration in carrying out duties regarding pipeline safety under 49 U.S.C. 60101 et seq. (the pipeline safety laws) and 49 U.S.C. 5101 et seq. (the hazardous material transportation laws).
(b) This subpart defines certain terms and prescribes procedures that are applicable to each proceeding described in this part.


Source: 45 FR 20413, Mar. 27, 1980, unless otherwise noted.

§ 190.3 Definitions.
As used in this part:
Hearing means an informal conference or a proceeding for oral presentation. Unless otherwise specifically prescribed in this part, the use of “hearing” is not intended to require a hearing on the record in accordance with section 554 of title 5, U.S.C.
OPS means the Office of Pipeline Safety, which is part of the Research and Special Programs Administration, U.S. Department of Transportation.
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.
Presiding Official means the person who conducts any hearing relating to
§ 190.5  Service.

(a) Each order, notice, or other document required to be served under this part shall be served personally or by registered or certified mail.

(b) Service upon a person’s duly authorized representative or agent constitutes service upon that person.

(c) Service by registered or certified mail is complete upon mailing. An official U. S. Postal Service receipt from the registered or certified mailing constitutes prima facie evidence of service.

§ 190.7  Subpoenas; witness fees.

(a) The Administrator, RSPA, the Chief Counsel, RSPA, or the official designated by the Administrator, RSPA, to preside over a hearing convened in accordance with this part, may sign and issue subpoenas individually on their own initiative or, upon request and adequate showing by any person participating in the proceeding that the information sought will materially advance the proceeding.

(b) A subpoena may require the attendance of a witness, or the production of documentary or other tangible evidence in the possession or under the control of person served, or both.

(c) A subpoena may be served personally by any person who is not an interested person and is not less than 18 years of age, or by certified or registered mail.

(d) Service of a subpoena upon the person named therein shall be made by delivering a copy of the subpoena to such person and by tendering the fees for one day’s attendance and mileage as specified by paragraph (g) of this section. When a subpoena is issued at the instance of any officer or agency of the United States, fees and mileage need not be tendered at the time of service. Delivery of a copy of a subpoena and tender of the fees to a natural person may be made by handing them to the person, leaving them at the person’s office with the person in charge thereof, leaving them at the person’s dwelling place or usual place of abode with some person of suitable age and discretion then residing therein, by mailing them by registered or certified mail to the person at the last known address, or by any method whereby actual notice is given to the person and the fees are made available prior to the return date.

(e) When the person to be served is not a natural person, delivery of a copy of the subpoena and tender of the fees may be effected by handing them to a designated agent or representative for service, or to any officer, director, or agent in charge of any office of the person, or by mailing them by registered or certified mail to that agent or representative and the fees are made available prior to the return date.

(f) The original subpoena bearing a certificate of service shall be filed with the official having responsibility for the proceeding in connection with which the subpoena was issued.

(g) A subpoenaed witness shall be paid the same fees and mileage as would be paid to a witness in a proceeding in the district courts of the United States. The witness fees and mileage shall be paid by the person at whose instance the subpoena was issued.

(h) Notwithstanding the provisions of paragraph (g) of this section, and upon request, the witness fees and mileage may be paid by the RSPA if the official who issued the subpoena determines on the basis of good cause shown, that:
Research and Special Programs Administration, DOT

§ 190.11

(1) The presence of the subpoenaed witness will materially advance the proceeding; and

(2) The person at whose instance the subpoena was issued would suffer a serious hardship if required to pay the witness fees and mileage.

(i) Any person to whom a subpoena is directed may, prior to the time specified therein for compliance, but in no event more than 10 days after the date of service of such subpoena, apply to the official who issued the subpoena, or if the person is unavailable, to the Administrator, RSPA to quash or modify the subpoena. The application shall contain a brief statement of the reasons relied upon in support of the action sought therein. The Administrator, RSPA, or this issuing official, as the case may be, may:

(1) Deny the application;

(2) Quash or modify the subpoena; or

(3) Condition a grant or denial of the application to quash or modify the subpoena upon the satisfaction of certain just and reasonable requirements. The denial may be summary.

(j) Upon refusal to obey a subpoena served upon any person under the provisions of this section, the RSPA may request the Attorney General to seek the aid of the U. S. District Court for any District in which the person is found to compel that person, after notice, to appear and give testimony, or to appear and produce the subpoenaed documents before the RSPA, or both.


§ 190.9 Petitions for finding or approval.

(a) In circumstances where a rule contained in parts 192, 193 and 195 of this chapter authorizes the Administrator to make a finding or approval, an operator may petition the Administrator for such a finding or approval.

(b) Each petition must refer to the rule authorizing the action sought and contain information or arguments that justify the action. Unless otherwise specified, no public proceeding is held on a petition before it is granted or denied. After a petition is received, the Administrator or participating state agency notifies the petitioner of the disposition of the petition or, if the request requires more extensive consideration or additional information or comments are requested and delay is expected, of the date by which action will be taken.

(1) For operators seeking a finding or approval involving intrastate pipeline transportation, petitions must be sent to:

(i) The State agency certified to participate under 49 U.S.C. 60105.

(ii) Where there is no state agency certified to participate, the Administrator, Research and Special Programs Administration, 400 7th Street SW., Washington, DC 20590.

(2) For operators seeking a finding or approval involving interstate pipeline transportation, petitions must be sent to the Administrator, Research and Special Programs Administration, 400 7th Street SW., Washington, DC 20590.

(c) All petitions must be received at least 90 days prior to the date by which the operator requests the finding or approval to be made.

(d) The Administrator will make all findings or approvals of petitions initiated under this section. A participating state agency receiving petitions initiated under this section shall provide the Administrator a written recommendation as to the disposition of any petition received by them. Where the Administrator does not reverse or modify a recommendation made by a state agency within 10 business days of its receipt, the recommended disposition shall constitute the Administrator’s decision on the petition.


§ 190.11 Availability of informal guidance and interpretive assistance.

(a) Availability of telephonic and Internet assistance. (1) RSPA has established a website on the Internet and a telephone line at the Office of Pipeline Safety headquarters where small operators and others can obtain information and advice about compliance with pipeline safety regulations, 49 CFR parts 190–199. The website and telephone line are staffed by personnel from RSPA’s Office of Pipeline Safety.
§ 190.201 Purpose and scope.

(a) This subpart describes the enforcement authority and sanctions exercised by the Associate Administrator, OPS for achieving and maintaining pipeline safety. It also prescribes the procedures governing the exercise of that authority and the imposition of those sanctions.

(b) A person who is the subject of action pursuant to this subpart may be represented by legal counsel at all stages of the proceeding.

acceptable plan with the owner of those facilities and, where appropriate, the National Transportation Safety Board for performing the testing.

(e) When the information obtained from an inspection or from other appropriate sources indicates that further OPS action is warranted, the OPS issues a warning letter under §190.205 or initiates one or more of the enforcement proceedings prescribed in §§190.207 through 190.235.


§ 190.205 Warning letters.

Upon determining that a probable violation of 49 U.S.C. 60101 et seq. or any regulation or order issued thereunder has occurred, the Associate Administrator, OPS, may issue a Warning Letter notifying the owner or operator of the probable violation and advising the owner or operator to correct it or be subject to enforcement action under §§190.207 through 190.235.

[Amdt. 190–6, 61 FR 38403, July 24, 1996]

§ 190.207 Notice of probable violation.

(a) Except as otherwise provided by this subpart, a Regional Director begins an enforcement proceeding by serving a notice of probable violation on a person charging that person with a probable violation of 49 U.S.C. 60101 et seq. or any regulation or order issued thereunder.

(b) A notice of probable violation issued under this section shall include:

(1) Statement of the provisions of the laws, regulations or orders which the respondent is alleged to have violated and a statement of the evidence upon which the allegations are based;

(2) Notice of response options available to the respondent under §190.209;

(3) If a civil penalty is proposed under §190.221, the amount of the proposed civil penalty and the maximum civil penalty for which respondent is liable under law; and

(4) If a compliance order is proposed under §190.217, a statement of the remedial action being sought in the form of a proposed compliance order.

(c) The Associate Administrator, OPS may amend a notice of probable violation at any time prior to issuance of a final order under §190.213. If an amendment includes any new material allegations of fact or proposes an increased civil penalty amount or new or additional remedial action under §190.217, the respondent shall have the opportunity to respond under §190.209.


§ 190.209 Response options.

Within 30 days of receipt of a notice of probable violation, the respondent shall respond to the Regional Director who issued the notice in the following way:

(a) When the notice contains a proposed civil penalty—

(1) Pay the proposed civil penalty as provided in §190.227 and close the case with prejudice to the respondent;

(2) Submit written explanations, information or other materials in answer to the allegations or in mitigation of the proposed civil penalty; or

(3) Request a hearing under §190.211.

(b) When the notice contains a proposed compliance order—

(1) Agree to the proposed compliance order;

(2) Request the execution of a consent order under §190.219;

(3) Object to the proposed compliance order and submit written explanations, information or other materials in answer to the allegations in the notice of probable violation; or

(4) Request a hearing under §190.211.

(c) Failure of the respondent to respond in accordance with paragraph (a) of this section or, when applicable, paragraph (c) of this section, constitutes a waiver of the right to contest the allegations in the notice of probable violation and authorizes the Associate Administrator, OPS, without further notice to the respondent, to find facts to be as alleged in the notice of probable violation and to issue a final order under §190.213.

§ 190.211 Hearing.

(a) A request for a hearing provided for in this part must be accompanied by a statement of the issues that the respondent intends to raise at the hearing. The issues may relate to the allegations in the notice, the proposed corrective action (including a proposed amendment, a proposed compliance order, or a proposed hazardous facility order), or the proposed civil penalty amount. A respondent’s failure to specify an issue may result in waiver of the respondent’s right to raise that issue at the hearing. The respondent’s request must also indicate whether or not the respondent will be represented by counsel at the hearing.

(b) A telephone hearing will be held if the amount of the proposed civil penalty or the cost of the proposed corrective action is less than $10,000, unless the respondent submits a written request for an in-person hearing. Hearings are held in a location agreed upon by the presiding official, OPS and the respondent.

(c) An attorney from the Office of the Chief Counsel, Research and Special Programs Administration, serves as the presiding official at the hearing.

(d) The hearing is conducted informally without strict adherence to rules of evidence. The respondent may submit any relevant information and material and call witnesses on the respondent’s behalf. The respondent may also examine the evidence and witnesses presented by the government. No detailed record of a hearing is prepared.

(e) Upon request by respondent, and whenever practicable, the material in the case file pertinent to the issues to be determined is provided to the respondent 30 days before the hearing. The respondent may respond to or rebut this material at the hearing.

(f) During the hearing, the respondent may offer any facts, statements, explanations, documents, testimony or other items which are relevant to the issues under consideration.

(g) At the close of the respondent’s presentation, the presiding official may present or allow the presentation of any OPS rebuttal information. The respondent may then respond to that information.

(h) After the evidence in the case has been presented, the presiding official shall permit argument on the issues under consideration.

(i) The respondent may also request an opportunity to submit further written material for inclusion in the case file. The presiding official shall allow a reasonable time for the submission of the material and shall specify the date by which it must be submitted. If the material is not submitted within the time prescribed, the case shall proceed to final action without the material.

(j) After submission of all materials during and after the hearing, the presiding official shall prepare a written recommendation as to final action in the case. This recommendation, along with any material submitted during and after the hearing, shall be included in the case file which is forwarded to the Associate Administrator, OPS for final administrative action.

49 CFR Ch. I (10–1–01 Edition)

§ 190.213 Final order.

(a) After a hearing under § 190.211 or, if no hearing has been held, after expiration of the 30 day response period prescribed in § 190.209, the case file of an enforcement proceeding commenced under § 190.207 is forwarded to the Associate Administrator, OPS for issuance of a final order.

(b) The case file of an enforcement proceeding commenced under § 190.207 includes:

1. The inspection reports and any other evidence of alleged violations;
2. A copy of the notice of probable violation issued under § 190.207;
3. Material submitted by the respondent in accord with § 190.209 in response to the notice of probable violation;
4. The Regional Director’s evaluation of response material submitted by the respondent and recommendation for final action to be taken under this section; and
5. In cases involving a § 190.211 hearing, any material submitted during and after the hearing and the presiding official’s recommendation for final action to be taken under this section.
Based on a review of a case file described in paragraph (b) of this section, the Associate Administrator, OPS shall issue a final order that includes—

1. A statement of findings and determinations on all material issues, including a determination as to whether each alleged violation has been proved;

2. If a civil penalty is assessed, the amount of the penalty and the procedures for payment of the penalty, provided that the assessed civil penalty may not exceed the penalty proposed in the notice of probable violation; and

3. If a compliance order is issued, a statement of the actions required to be taken by the respondent and the time by which such actions must be accomplished.

(d) Except as provided by §190.215, an order issued under this section regarding an enforcement proceeding is considered final administrative action on that enforcement proceeding.

(e) It is the policy of the Associate Administrator, OPS to issue a final order under this section within 45 days of receipt of the case file, unless it is found impracticable to take action within that time. In cases where it is so found and delay beyond that period is expected to be substantial, notice of that fact and the date by which it is expected that action will be taken is issued to the respondent.


§ 190.217 Compliance orders generally.

When the Associate Administrator, OPS has reason to believe that a person is engaging in conduct which involves a violation of the 49 U.S.C. 60101 et seq. or any regulation issued thereunder, and if the nature of the violation, and the public interest warrant, the Associate Administrator, OPS may conduct proceedings under §§190.207 through 190.213 of this part to determine the nature and extent of the violations and to issue an order directing compliance.

[Amdt. 190–6, 61 FR 18514, Apr. 26, 1996]

§ 190.219 Consent order.

(a) At any time before the issuance of a compliance order under §190.213 the

(c) The Associate Administrator, OPS does not consider repetitious information, arguments, or petitions.

(d) The filing of a petition under this section stays the payment of any civil penalty assessed. However, unless the Associate Administrator, OPS otherwise provides, the order, including any required corrective action, is not stayed.

(e) The Associate Administrator, OPS may grant or deny, in whole or in part, any petition for reconsideration without further proceedings. In the event the Associate Administrator, OPS reconsiders a final order, a final decision on reconsideration may be issued without further proceedings, or, in the alternative, additional information, data, and comment may be requested by the Associate Administrator, OPS as deemed appropriate.

(f) It is the policy of the Associate Administrator, OPS to issue notice of the action taken on a petition for reconsideration within 20 days after receipt of the petition, unless it is found impracticable to take action within that time. In cases where it is so found and delay beyond that period is expected to be substantial, notice of that fact and the date by which it is expected that action will be taken is issued to the respondent.

§ 190.221 Associate Administrator, OPS and the respondent may agree to dispose of the case by joint execution of a consent order. Upon such joint execution, the consent order shall be considered a final order under §190.213.

(b) A consent order executed under paragraph (a) of this section shall include:

(1) An admission by the respondent of all jurisdictional facts;

(2) An express waiver of further procedural steps and of all right to seek judicial review or otherwise challenge or contest the validity of that order;

(3) An acknowledgement that the notice of probable violation may be used to construe the terms of the consent order; and

(4) A statement of the actions required of the respondent and the time by which such actions shall be accomplished.

[C FR 20413, Mar. 27, 1980, as amended by Amdt. 190–6, 61 FR 18514, Apr. 26, 1996]

CIVIL PENALTIES

§ 190.223 Maximum penalties.

(a) Any person who is determined to have violated a provision of 49 U.S.C. 60101 et seq. or any regulation or order issued thereunder, is subject to a civil penalty not to exceed $25,000 for each violation, and if any such violation is a continuing one, each day of violation constitutes a separate offense.

(c) Any person who is determined to have violated any standard or order under 49 U.S.C. 60103 shall be subject to a civil penalty of not to exceed $50,000, which penalty shall be in addition to any other penalties to which such person may be subject under paragraph (a) of this section.

(d) No person shall be subject to a civil penalty under this section for the violation of any requirement of this subchapter and an order issued under §190.217, §190.219 or §190.233 if both violations are based on the same act.


§ 190.225 Assessment considerations.

The Associate Administrator, OPS assesses a civil penalty under this part only after considering:

(a) The nature, circumstances and gravity of the violation;

(b) The degree of the respondent’s culpability;

(c) The respondent’s history of prior offenses;

(d) The respondent’s ability to pay;

(e) Any good faith by the respondent in attempting to achieve compliance;

(f) The effect on the respondent’s ability to continue in business; and

(g) Such other matters as justice may require.

[C FR 20413, Mar. 27, 1980, as amended by Amdt. 190–6, 61 FR 18514, Apr. 26, 1996]

§ 190.227 Payment of penalty.

(a) Except for payments exceeding $10,000, payment of a civil penalty proposed or assessed under this subpart may be made by certified check or money order (containing the CPF Number for this case) payable to “U.S. Department of Transportation” to the Federal Aviation Administration, Mike Monroney Aeronautical Center, Financial Operations Division (AMZ–320), P.O. Box 25770, Oklahoma City, OK 73125, or by wire transfer through the Federal Reserve Communications System (Fedwire) to the account of the U.S. Treasury. Payments exceeding
§ 190.233

$10,000 must be made by wire transfer. Payments, or in the case of wire transfers, notices of payment, must be sent to the Chief, General Accounting Branch (M–86.2), Accounting Operations Division, Office of the Secretary, room 2228, Department of Transportation, 400 Seventh Street, SW, Washington, DC 20590.

(b) Payment of a civil penalty assessed in a final order issued under §190.213 or affirmed in a decision on a petition for reconsideration must be made within 20 days after receipt of the final order or decision. Failure to do so will result in the initiation of collection action, including the accrual of interest and penalties, in accordance with 31 U.S.C. 3717 and 49 CFR part 89.

§ 190.229 Criminal penalties generally.

(a) Any person who willfully and knowingly violates a provision of 49 U.S.C. 60101 et seq. or any regulation or order issued thereunder shall upon conviction be subject for each offense to a fine of not more than $25,000 and imprisonment for not more than five years, or both.

(b) Any person who willfully violates a regulation or order under this subchapter issued under the authority of 49 U.S.C. 5101 et seq. as applied to offshore gas gathering lines shall upon conviction be subject for each offense to a fine of not more than $25,000, imprisonment for a term not to exceed 5 years, or both.

(c) Any person who willfully and knowingly injures or destroys, or attempts to injure or destroy, any interstate transmission facility or any interstate pipeline facility (as those terms are defined in 49 U.S.C. 60101 et seq.) shall, upon conviction, be subject for each offense to a fine of not more than $25,000, imprisonment for a term not to exceed 15 years, or both.

(d) Any person who willfully and knowingly defaces, damages, removes, destroys any pipeline sign, right-of-way marker, or marine buoy required by 49 U.S.C. 60101 et seq., or 49 U.S.C. 5101 et seq., or any regulation or order issued thereunder shall, upon conviction, be subject for each offense to a fine of not more than $5,000, imprisonment for a term not to exceed 1 year, or both.

(e) No person shall be subject to criminal penalties under paragraph (a) of this section for violation of any regulation and the violation of any order issued under §190.217, §190.219 or §190.229 if both violations are based on the same act.


§ 190.231 Referral for prosecution.

If an employee of the Research and Special Programs Administration becomes aware of any actual or possible activity subject to criminal penalties under §190.229, the employee reports it to the Office of the Chief Counsel, Research and Special Programs Administration, U.S. Department of Transportation, Washington, DC 20590. The Chief Counsel refers the report to OPS for investigation. Upon completion of the investigation and if appropriate, the Chief Counsel refers the report to the Department of Justice for criminal prosecution of the offender.

[Amdt. 190–6, 61 FR 18515, Apr. 26, 1996]

§ 190.233 Specific relief

(a) Except as provided by paragraph (b) of this section, if the Associate Administrator, OPS finds, after reasonable notice and opportunity for hearing in accord with paragraph (c) of this section, and §190.211(a), a particular pipeline facility to be hazardous to life or property, the Associate Administrator, OPS shall issue an order pursuant to this section requiring the owner or operator of the facility to take corrective action. Corrective action may include suspended or restricted use of the facility, physical inspection, testing, repair, replacement, or other action, as appropriate.

(b) The Associate Administrator, OPS may waive the requirement for notice and hearing under paragraph (a) of this section before issuing an order pursuant to this section when the Associate Administrator, OPS determines that the failure to do so would result in
the likelihood of serious harm to life or property. However, the Associate Administrator, OPS shall include in the order an opportunity for hearing as soon as practicable after issuance of the order. The provisions of paragraph (c)(2) of this section apply to an owner or operator’s decision to exercise such an opportunity for hearing. The purpose of such a post-order hearing is for the Associate Administrator, OPS to determine whether the order should remain in effect or be rescinded or suspended in accord with paragraph (g) of this section.

(c) Notice and hearing:

(1) Written notice that OPS intends to issue an order under this section shall be served in accordance with §190.5, upon the owner or operator of an alleged hazardous facility. The notice shall allege the existence of a hazardous facility, stating the facts and circumstances supporting the issuance of a “hazardous facility order”, and providing the owner or operator an opportunity for a hearing, identifying the time and location of the hearing.

(2) An owner or operator elects to exercise his opportunity for a hearing under this section, by notifying the Associate Administrator, OPS of that election in writing within 10 days of service of the notice provided under paragraph (c)(1) of this section or, under paragraph (b) of this section when applicable. Absence of such written notification waives an owner or operator’s opportunity for a hearing and allows the Associate Administrator, OPS to proceed to issue a “hazardous facility order” in accordance with paragraphs (d) through (h) of this section.

(3) A hearing under this section shall be presided over by an attorney from the Office of Chief Counsel, Research and Special Programs Administration, acting as Presiding Official, and conducted without strict adherence to rules of evidence. The Presiding Official presents the allegations contained in the notice issued under this section. The owner or operator of the alleged hazardous facility may submit any relevant information or materials, call witnesses and present arguments on the issue of whether or not a “hazardous facility order” should be issued.

(4) Within 48 hours after conclusion of a hearing under this section, the Presiding Official shall submit a recommendation to the Associate Administrator, OPS as to whether or not a “hazardous facility order” is required. Upon receipt of the recommendation, the Associate Administrator, OPS shall proceed in accordance with paragraphs (d) through (h) of this section. If the Associate Administrator, OPS finds the facility to be hazardous to life or property the Associate Administrator, OPS shall issue an order in accordance with this section. If the Associate Administrator, OPS does not find the facility to be hazardous to life or property, the Associate Administrator, OPS shall dismiss the allegations contained in the notice, and promptly notify the owner or operator in writing by service as prescribed in §190.5.

(d) The Associate Administrator, OPS may find a pipeline facility to be hazardous under paragraph (a) of this section:

(1) If under the facts and circumstances the Associate Administrator, OPS determines the particular facility is hazardous to life or property; or

(2) If the pipeline facility or a component thereof has been constructed or operated with any equipment, material, or technique which the Associate Administrator, OPS determines is hazardous to life or property, unless the operator involved demonstrates to the satisfaction of the Associate Administrator, OPS that, under the particular facts and circumstances involved, such equipment, material, or technique is not hazardous to life or property.

(e) In making a determination under paragraph (d) of this section, the Associate Administrator, OPS shall consider, if relevant:

(1) The characteristics of the pipe and other equipment used in the pipeline facility involved, including its age, manufacturer, physical properties (including its resistance to corrosion and deterioration), and the method of its manufacture, construction or assembly;

(2) The nature of the materials transported by such facility (including their corrosive and deteriorative qualities), the sequence in which such materials
Research and Special Programs Administration, DOT

190.237 Amendment of plans or procedures.

(a) A Regional Director begins a proceeding to determine whether an operator’s plans or procedures required under parts 192, 193, 195, and 199 of this subchapter are inadequate to assure safe operation of a pipeline facility by issuing a notice of amendment. The notice shall provide an opportunity for a hearing under §190.211 of this part and shall specify the alleged inadequacies and the proposed action for revision of the plans or procedures. The notice shall allow the operator 30 days after receipt of the notice to submit written comments or request a hearing. After considering all material presented in writing or at the hearing, the Associate Administrator, OPS shall determine whether the plans or procedures are inadequate as alleged and order the required amendment if they are inadequate, or withdraw the notice if they are not. In determining the adequacy of an operator’s plans or procedures, the Associate Administrator, OPS shall consider:

(1) Relevant available pipeline safety data;
(2) Whether the plans or procedures are appropriate for the particular type
§ 190.301 Scope.

This subpart prescribes general rulemaking procedures for the issue, amendment, and repeal of Pipeline Safety Program regulations of the Research and Special Programs Administration of the Department of Transportation.

§ 190.303 Delegations.

For the purposes of this subpart, Administrator means the Administrator, Research and Special Programs Administration, or his or her delegate.

§ 190.305 Regulatory dockets.

(a) Information and data considered relevant by the Administrator relating to rulemaking actions, including notices of proposed rulemaking; comments received in response to notices; petitions for rulemaking and reconsideration; denials of petitions for rulemaking and reconsideration; records of additional rulemaking proceedings under §190.325; and final regulations are maintained by the Research and Special Programs Administration at 400 7th Street, SW, Washington, D.C. 20590–0001.

(b) Any person may examine any docketed material at the offices of the Research and Special Programs Administration at any time during regular business hours after the docket is established, except material which the Administrator determines should be withheld from public disclosure under applicable provisions of any statute administered by the Administrator and section 552(b) of Title 5, United States Code, and may obtain a copy of it upon payment of a fee.

§ 190.307 Records.

Records of the Research and Special Programs Administration relating to rulemaking proceedings are available for inspection as provided in section 552(b) of title 5, United States Code, and part 7 of the Regulations of the Office of the Secretary of Transportation (part 7 of this title).

§ 190.309 Where to file petitions.

Petitions for extension of time to comment submitted under §190.319, petitions for hearings submitted under §190.327, petitions for rulemaking submitted under §190.331, and petitions for reconsideration submitted under §190.335 must be submitted to: Administrator, Research and Special Programs Administration, U.S. Department of Transportation, 400 7th Street, SW., Washington, D.C. 20590–0001.

§ 190.311 General.

Unless the Administrator, for good cause, finds that notice is impracticable, unnecessary, or contrary to the public interest, and incorporates that finding and a brief statement of the reasons for it in the rule, a notice of proposed rulemaking is issued and interested persons are invited to participate in the rulemaking proceedings with respect to each substantive rule.

§ 190.313 Initiation of rulemaking.

The Administrator initiates rulemaking on his or her own motion; however, in so doing, the Administrator may use discretion to consider the recommendations of other agencies of the United States or of other interested persons including those of any technical advisory body established by statute for that purpose.

§ 190.315 Contents of notices of proposed rulemaking.

(a) Each notice of proposed rulemaking is published in the Federal Register, unless all persons subject to
§ 190.321 Contents of written comments.

All written comments must be in English. It is requested, but not required, that five copies be submitted. Any interested person should submit as part of written comments all material considered relevant to any statement of fact. Incorporation of material by reference should be avoided; however, where necessary, such incorporated material shall be identified by document title and page.

§ 190.323 Consideration of comments received.

All timely comments and the recommendations of any technical advisory body established by statute for the purpose of reviewing the proposed rule concerned are considered before final action is taken on a rulemaking proposal. Late filed comments are considered so far as practicable.

§ 190.325 Additional rulemaking proceedings.

The Administrator may initiate any further rulemaking proceedings that the Administrator finds necessary or desirable. For example, interested persons may be invited to make oral arguments, to participate in conferences between the Administrator or the Administrator’s representative and interested persons, at which minutes of the conference are kept, to appear at informal hearings presided over by officials designated by the Administrator at which a transcript of minutes are kept, or participate in any other proceeding to assure informed administrative action and to protect the public interest.

§ 190.327 Hearings.

(a) If a notice of proposed rulemaking does not provide for a hearing, any interested person may petition the Administrator for an informal hearing. The petition must be received by the Administrator not later than 20 days before expiration of the time stated in the notice. The filing of the petition does not automatically result in the scheduling of a hearing. A petition is granted only if the petitioner shows good cause for a hearing. If a petition for a hearing is granted, notice of the
§ 190.329 Adoption of final rules.

Final rules are prepared by representatives of the Office of Pipeline Safety and the Office of the Chief Counsel. The regulation is then submitted to the Administrator for consideration. If the Administrator adopts the regulation, it is published in the Federal Register, unless all persons subject to it are named and are personally served with a copy of it.

§ 190.331 Petitions for rulemaking.

(a) Any interested person may petition the Associate Administrator for Pipeline Safety to establish, amend, or repeal a substantive regulation, or may petition the Chief Counsel to establish, amend, or repeal a procedural regulation.

(b) Each petition filed under this section must:

1. Summarize the proposed action and explain its purpose;
2. State the text of the proposed rule or amendment, or specify the rule proposed to be repealed;
3. Explain the petitioner's interest in the proposed action and the interest of any party the petitioner represents; and
4. Provide information and arguments that support the proposed action, including relevant technical, scientific or other data as available to the petitioner, and any specific known cases that illustrate the need for the proposed action.

(c) If the potential impact of the proposed action is substantial, and information and data related to that impact are available to the petitioner, the Associate Administrator or the Chief Counsel may request the petitioner to provide—

1. The costs and benefits to society and identifiable groups within society, quantifiable and otherwise;
2. The direct effects (including pre-emption effects) of the proposed action on States, on the relationship between the Federal Government and the States, and on the distribution of power and responsibilities among the various levels of government;
3. The regulatory burden on small businesses, small organizations and small governmental jurisdictions;
4. The recordkeeping and reporting requirements and to whom they would apply; and
5. Impacts on the quality of the natural and social environments.

(d) The Associate Administrator or Chief Counsel may return a petition that does not comply with the requirements of this section, accompanied by a written statement indicating the deficiencies in the petition.

§ 190.333 Processing of petition.

(a) General. Unless the Associate Administrator or the Chief Counsel otherwise specifies, no public hearing, argument, or other proceeding is held directly on a petition before its disposition under this section.

(b) Grants. If the Associate Administrator or the Chief Counsel determines that the petition contains adequate justification, he or she initiates rulemaking action under this subpart.

(c) Denials. If the Associate Administrator or the Chief Counsel determines that the petition does not justify rulemaking, the petition is denied.

(d) Notification. The Associate Administrator or the Chief Counsel will notify a petitioner, in writing, of the decision to grant or deny a petition for rulemaking.

§ 190.335 Petitions for reconsideration.

(a) Except as provided in §190.339(d), any interested person may petition the Associate Administrator for reconsideration of any regulation issued under
this subpart, or may petition the Chief Counsel for reconsideration of any procedural regulation issued under this subpart and contained in this subpart. It is requested, but not required, that three copies be submitted. The petition must be received not later than 30 days after publication of the rule in the FEDERAL REGISTER. Petitions filed after that time will be considered as petitions filed under §190.331. The petition must contain a brief statement of the complaint and an explanation as to why compliance with the rule is not practicable, is unreasonable, or is not in the public interest.

(b) If the petitioner requests the consideration of additional facts, the petitioner must state the reason they were not presented to the Associate Administrator or the Chief Counsel within the prescribed time.

(c) The Associate Administrator or the Chief Counsel does not consider repetitious petitions.

(d) Unless the Associate Administrator or the Chief Counsel otherwise provides, the filing of a petition under this section does not stay the effectiveness of the rule.

§190.337 Proceedings on petitions for reconsideration.

(a) The Associate Administrator or the Chief Counsel may grant or deny, in whole or in part, any petition for reconsideration without further proceedings, except where a grant of the petition would result in issuance of a new final rule. In the event that the Associate Administrator or the Chief Counsel determines to reconsider any regulation, a final decision on reconsideration may be issued without further proceedings, or an opportunity to submit comment or information and data as deemed appropriate, may be provided. Whenever the Associate Administrator or the Chief Counsel determines that a petition should be granted or denied, the Office of the Chief Counsel prepares a notice of the grant or denial of a petition for reconsideration, for issuance to the petitioner, and the Associate Administrator or the Chief Counsel issues it to the petitioner. The Associate Administrator or the Chief Counsel may consolidate petitions relating to the same rules.

(b) It is the policy of the Associate Administrator or the Chief Counsel to issue notice of the action taken on a petition for reconsideration within 90 days after the date on which the regulation in question is published in the FEDERAL REGISTER, unless it is found impracticable to take action within that time. In cases where it is so found and the delay beyond that period is expected to be substantial, notice of that fact and the date by which it is expected that action will be taken is issued to the petitioner and published in the FEDERAL REGISTER.

§190.338 Appeals.

(a) Any interested person may appeal a denial of the Associate Administrator or the Chief Counsel, issued under §190.333 or §190.337, to the Administrator.

(b) An appeal must be received within 20 days of service of written notice to petitioner of the Associate Administrator’s or the Chief Counsel’s decision, or within 20 days from the date of publication of the decision in the FEDERAL REGISTER, and should set forth the contested aspects of the decision as well as any new arguments or information.

(c) It is requested, but not required, that three copies of the appeal be submitted to the Administrator.

(d) Unless the Administrator otherwise provides, the filing of an appeal under this section does not stay the effectiveness of any rule.

§190.339 Direct final rulemaking.

(a) Where practicable, the Administrator will use direct final rulemaking to issue the following types of rules:

(1) Minor, substantive changes to regulations;

(2) Incorporation by reference of the latest edition of technical or industry standards;

(3) Extensions of compliance dates; and

(4) Other noncontroversial rules where the Administrator determines that use of direct final rulemaking is in the public interest, and that a regulation is unlikely to result in adverse comment.

(b) The direct final rule will state an effective date. The direct final rule will
also state that unless an adverse comment or notice of intent to file an adverse comment is received within the specified comment period, generally 60 days after publication of the direct final rule in the Federal Register, the Administrator will issue a confirmation document, generally within 15 days after the close of the comment period, advising the public that the direct final rule will either become effective on the date stated in the direct final rule or at least 30 days after the publication date of the confirmation document, whichever is later.

(c) For purposes of this section, an adverse comment is one which explains why the rule would be inappropriate, including a challenge to the rule’s underlying premise or approach, or would be ineffective or unacceptable without a change. Comments that are frivolous or insubstantial will not be considered adverse under this procedure. A comment recommending a rule change in addition to the rule will not be considered an adverse comment, unless the commenter states why the rule would be ineffective without the additional change.

(d) Only parties who filed comments to a direct final rule issued under this section may petition under §190.335 for reconsideration of that direct final rule.

(e) If an adverse comment or notice of intent to file an adverse comment is received, a timely document will be published in the Federal Register advising the public and withdrawing the direct final rule in whole or in part. The Administrator may then incorporate the adverse comment into a subsequent direct final rule or may publish a notice of proposed rulemaking. A notice of proposed rulemaking will provide an opportunity for public comment, generally a minimum of 60 days, and will be processed in accordance with §§190.311–190.329.

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS

§ 191.1 Scope.

(a) This part prescribes requirements for the reporting of incidents, safety-related conditions, and annual pipeline summary data by operators of gas pipeline facilities located in the United States or Puerto Rico, including pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to—

1. Offshore gathering of gas upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream; or

2. Onshore gathering of gas outside of the following areas:
§ 191.3 Definitions.

As used in this part and the RSPA Forms referenced in this part—

Administrator means the Administrator of the Research and Special Programs Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation.

Gas means natural gas, flammable gas, or gas which is toxic or corrosive; Incident means any of the following events:

1. An event that involves a release of gas from a pipeline or of liquefied natural gas or gas from an LNG facility and
   (i) A death, or personal injury necessitating in-patient hospitalization; or
   (ii) Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more.

2. An event that results in an emergency shutdown of an LNG facility.

3. An event that is significant, in the judgement of the operator, even though it did not meet the criteria of paragraphs (1) or (2).

LNG facility means a liquefied natural gas facility as defined in §193.2007 of part 193 of this chapter;

Master Meter System means a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as by rents;

Municipality means a city, county, or any other political subdivision of a State;

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 engages in the transportation of gas;

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;

Pipeline or Pipeline System means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

State includes each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico;

Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas in or affecting interstate or foreign commerce.

§ 191.5 Telephonic notice of certain incidents.

(a) At the earliest practicable moment following discovery, each operator shall give notice in accordance with paragraph (b) of this section of each incident as defined in §191.3.
§ 191.7

(b) Each notice required by paragraph (a) of this section shall be made by telephone to 800-424-8802 (in Washington, DC, 267-2675) and shall include the following information.

(1) Names of operator and person making report and their telephone numbers.

(2) The location of the incident.

(3) The time of the incident.

(4) The number of fatalities and personal injuries, if any.

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


§ 191.7 Addressee for written reports.

Each written report required by this part must be made to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 8417, 400 Seventh Street SW., Washington, DC 20590. However, incident and annual reports for intrastate pipeline transportation subject to the jurisdiction of a State agency pursuant to a certification under section 5(a) of the Natural Gas Pipeline Safety Act of 1968 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 for incident reports and not later than March 15 for annual reports to the Information Resources Manager. Safety-related condition reports required by § 191.23 for intrastate pipeline transportation must be submitted concurrently to that State agency, and if that agency acts as an agent of the Secretary with respect to interstate transmission facilities, safety-related condition reports for these facilities must be submitted concurrently to that agency.

[Amdt. 191–4, 53 FR 24949, July 1, 1988]

§ 191.9 Distribution system: Incident report.

(a) Except as provided in paragraph (c) of this section, each operator of a distribution pipeline system shall submit Department of Transportation Form RSPA F 7100.1 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5.

(b) When additional relevant information is obtained after the report is submitted under paragraph (a) of this section, the operator shall make supplementary reports as deemed necessary with a clear reference by date and subject to the original report.

(c) The incident report required by this section need not be submitted with respect to master meter systems or LNG facilities.

[Amdt. 191–5, 49 FR 18960, May 3, 1984]

§ 191.11 Distribution system: Annual report.

(a) Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system shall submit an annual report for that system on Department of Transportation Form RSPA F 7100.1–1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(b) The annual report required by this section need not be submitted with respect to:

(1) Petroleum gas systems which serve fewer than 100 customers from a single source;

(2) Master meter systems; or

(3) LNG facilities.

[Amdt. 191–5, 49 FR 18960, May 3, 1984]

§ 191.13 Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines.

Each operator, primarily engaged in gas distribution, who also operates gas transmission or gathering pipelines shall submit separate reports for these pipelines as required by §§ 191.15 and 191.17. Each operator, primarily engaged in gas transmission or gathering, who also operates gas distribution pipelines shall submit separate reports for these pipelines as required by §§ 191.9 and 191.11.

[Amdt. 191–5, 49 FR 18961, May 3, 1984]
§ 191.15 Transmission and gathering systems: Incident report.

(a) Except as provided in paragraph (c) of this section, each operator of a transmission or a gathering pipeline system shall submit Department of Transportation Form RSPA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5.

(b) Where additional related information is obtained after a report is submitted under paragraph (a) of this section, the operator shall make a supplemental report as soon as practicable with a clear reference by date and subject to the original report.

(c) The incident report required by paragraph (a) of this section need not be submitted with respect to LNG facilities.


§ 191.17 Transmission and gathering systems: Annual report.

(a) Except as provided in paragraph (b) of this section, each operator of a transmission or a gathering pipeline system shall submit an annual report for that system on Department of Transportation Form RSPA 7100.2–1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(b) The annual report required by paragraph (a) of this section need not be submitted with respect to LNG facilities.

[Amendment 191–5, 49 FR 18961, May 3, 1984]

§ 191.19 Report forms.

Copies of the prescribed report forms are available without charge upon request from the address given in §191.17. Additional copies in this prescribed format may be reproduced and used if in the same size and kind of paper. In addition, the information required by these forms may be submitted by any other means that is acceptable to the Administrator.

[Amendment 191–10, 61 FR 18316, Apr. 26, 1996]

§ 191.21 OMB control number assigned to information collection.

This section displays the control number assigned by the Office of Management and Budget (OMB) to the gas pipeline information collection requirements of the Office of Pipeline Safety pursuant to the Paperwork Reduction Act of 1980, Public Law 96–511.

It is the intent of this section to comply with the requirements of section 3507(f) of the Paperwork Reduction Act which requires that agencies display a current control number assigned by the Director of OMB for each agency information collection requirement.

OMB CONTROL NUMBER 2137–0522

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§ 191.23 Reporting safety-related conditions.

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §191.25 the existence of any of the following safety-related conditions involving facilities in service:

(1) In the case of a pipeline (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.

(2) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG.

(3) Any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG.

(4) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop
§ 191.25  Filing safety-related condition reports.

(a) Each report of a safety-related condition under § 191.23(a) must be filed
(received by the Associate Administrator, OPS) in writing within five
working days (not including Saturday, Sunday, or Federal Holidays) after the
day a representative of the operator first determines the condition ex-
ists, 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. Reports may be transmitted by
facsimile at (202) 366-7128.

(b) A report must be headed “Safety-Related Condition Report” and pro-
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 deter-
dined that the condition exists.

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

(6) Location of condition, with ref-
ence to the State (and town, city, or county) or offshore site, and as appro-
priate, nearest street address, offshore platform, survey station number, mile-
post, landmark, or name of pipeline.

(7) Description of the condition, in-
cluding 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 (in-
cluding reduction of pressure or shut-
don) before the report is submitted
and the planned follow-up or future corrective action, including the antici-
pated schedule for starting and con-
cluding such action.

(Amdt. 191–6, 53 FR 24949, Jul. 1, 1988; 53 FR
29800, Aug. 8, 1988, as amended by Amdt. 191–7,
54 FR 32344, Aug. 7, 1989; Amdt. 191–8, 54 FR
40678, Oct. 4, 1989; Amdt. 191–10, 61 FR 18516,
Apr. 26, 1996)

§ 191.27  Filing offshore pipeline condi-
tion reports.

(a) Each operator shall, within 60
days after completion of the inspection of all its underwater pipelines subject to
§ 192.612(a), report the following in-
formation:
(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 length 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 according to the Minerals Management Service or state offshore area and block number tract.

(b) The report shall be mailed to the Information Officer, Research and Special Programs Administration, Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590.


PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

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APPENDIX C TO PART 192—QUALIFICATION OF WELDERS FOR LOW STRESS LEVEL PIPE
APPENDIX D TO PART 192—CRITERIA FOR CATHODIC PROTECTION AND DETERMINATION OF MEASUREMENTS

AUTHORITY: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, and 60118; and 49 CFR 1.53.

SOURCE: 35 FR 13257, Aug. 19, 1970, unless otherwise noted.
§ 192.1 Scope of part.

(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to:

(i) Offshore pipelines upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

(ii) Onshore gathering of gas outside of the following areas:

(a) An area within the limits of any incorporated or unincorporated city, town, or village.

(b) Any designated residential or commercial area such as a subdivision, business or shopping center, or community development.

(iii) Onshore gathering of gas within inlets of the Gulf of Mexico except as provided in §192.612.

(iv) Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—

(a) Fewer than 10 customers, if no portion of the system is located in a public place; or

(b) A single customer, if the system is located entirely on the customer's premises (no matter if a portion of the system is located in a public place).

(v) On the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.


§ 192.3 Definitions.

As used in this part:

Abandoned means permanently removed from service.

Administrator means the Administrator of the Research and Special Programs Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation.

Distribution line means a pipeline other than a gathering or transmission line.

Exposed pipeline means a pipeline where the top of the pipe is protruding above the seabed in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.

Gas means natural gas, flammable gas, or gas which is toxic or corrosive.

Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main.

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.

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 seabed in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.

High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Line section means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

Listed specification means a specification listed in section I of appendix B of this part.

Low-pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

Main means a distribution line that serves as a common source of supply for more than one service line.

Low pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

Main means a distribution line that serves as a common source of supply for more than one service line.
Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of 1 year.

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

Municipality means a city, county, or any other political subdivision of a State.

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 engages in the transportation of gas.

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 including any trustee, receiver, assignee, or personal representative thereof.

Petroleum gas means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gage at 100 °F (38 °C).

Pipe means any pipe or tubing used in the transportation of gas, including pipe-type holders.

Pipeline means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

Pipeline facility means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

Service line means a distribution line that transports gas from a common source of supply to (1) a customer meter or the connection to a customer’s piping, whichever is farther downstream, or (2) the connection to a customer’s piping if there is no customer meter. A customer meter is the meter that measures the transfer of gas from an operator to a consumer.

SMYS means specified minimum yield strength is:

(1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

(2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §192.107(b).

State means each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

Transmission line means a pipeline, other than a gathering line, that:

(a) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;

(b) Operates at a hoop stress of 20 percent or more of SMYS; or

(c) Transports gas within a storage field. A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

Transportation of gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

§192.5 Class locations.

(a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.
§ 192.7 Incorporation by reference.

(a) Any documents or portions thereof incorporated by reference in this part are included in this part as though set out in full. When only a portion of a document is referenced, the remainder is not incorporated in this part.

(b) All incorporated materials are available for inspection in the Research and Special Programs Administration, 400 Seventh Street, SW., Washington, DC, and at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC. 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, the incorporated materials are available from the respective organizations listed in appendix A to this part.

(c) The full titles for the publications incorporated by reference in this part are provided in appendix A to this part. Numbers in parentheses indicate applicable editions. Earlier editions of documents listed or editions of documents formerly listed in previous editions of appendix A may be used for materials and components manufactured, designed, or installed in accordance with those earlier editions or earlier documents at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR for a listing of the earlier listed editions or documents.

§ 192.9 Gathering lines.

Except as provided in §§ 192.1 and 192.150, each operator of a gathering line must comply with the requirements of this part applicable to transmission lines.

[Amdt. 192–72, 59 FR 17281, Apr. 12, 1994]

§ 192.10 Outer continental shelf pipelines.

Operators of transportation pipelines on the Outer Continental Shelf (as defined in the Outer Continental Shelf Lands Act; 43 U.S.C. 1331) 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
§ 192.15 Rules of regulatory construction.

(a) As used in this part:

Includes means including but not limited to.

May means “is permitted to” or “is authorized to”.

May not means “is not permitted to” or “is not authorized to”.

Shall is used in the mandatory and imperative sense.
§ 192.16 Customer notification.

(a) This section applies to each operator of a service line who does not maintain the customer’s buried piping up to entry of the first building downstream, or, if the customer’s buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this section, “customer’s buried piping” does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, “maintain” means monitor for corrosion according to §192.465 if the customer’s buried piping is metallic, survey for leaks according to §192.723, and if an unsafe condition is found, shut off the flow of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe condition.

(b) Each operator shall notify each customer once in writing of the following information:

(1) The operator does not maintain the customer’s buried piping.

(2) If the customer’s buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.

(3) Buried gas piping should be—

(i) Periodically inspected for leaks;

(ii) Periodically inspected for corrosion if the piping is metallic; and

(iii) Repaired if any unsafe condition is discovered.

(4) When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.

(5) The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer’s buried piping.

(c) Each operator shall notify each customer not later than August 14, 1996, or 90 days after the customer first receives gas at a particular location, whichever is later. However, operators of master meter systems may continuously post a general notice in a prominent location frequented by customers.

(d) Each operator must make the following records available for inspection by the Administrator or a State agency participating under 49 U.S.C. 60105 or 60106:

(1) A copy of the notice currently in use; and

(2) Evidence that notices have been sent to customers within the previous 3 years.


Subpart B—Materials

§ 192.51 Scope.

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

§ 192.53 General.

Materials for pipe and components must be:

(a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

(b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and

(c) Qualified in accordance with the applicable requirements of this subpart.

§ 192.55 Steel pipe.

(a) New steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification; or

(2) It meets the requirements of—

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part; or

(3) It is used in accordance with paragraph (c) or (d) of this section.

(b) Used steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification and it
§ 192.63 Marking of materials.

(a) Except as provided in paragraph (d) of this section, each valve, fitting, length of pipe, and other component must be marked—

(1) As prescribed in the specification or standard to which it was manufactured, except that thermoplastic fittings must be marked in accordance with ASTM D 2513; or

(2) To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.
§ 192.65 Transportation of pipe.

In a pipeline to be 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:

(a) The transportation is performed in accordance with API RP 5L1.

(b) In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

§ 192.105 Design formula for steel pipe.

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

\[ P = \frac{2S}{D} \times F \times E \times T \]

\( P \) = Design pressure in pounds per square inch (kPa) gauge.

\( S \) = Yield strength in pounds per square inch (kPa) determined in accordance with §192.107.

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

\( t \) = Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with §192.109.

Additional wall thickness required for concurrent external loads in accordance with §192.105 may not be included in computing design pressure.

\( F \) = Design factor determined in accordance with §192.111.

\( E \) = Longitudinal joint factor determined in accordance with §192.113.

\( T \) = Temperature derating factor determined in accordance with §192.115.

(b) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900°F (482°C) at any time or is held above 600°F (316°C) for more than 1 hour.

§ 192.107 Yield strength (S) for steel pipe.

(a) For pipe that is manufactured in accordance with a specification listed in section I of appendix B of this part, the yield strength to be used in the design formula in §192.105 is the SMYS stated in the listed specification, if that value is known.

(b) For pipe that is manufactured in accordance with a specification not listed in section I of appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in §192.105 is one of the following:

(1) If the pipe is tensile tested in accordance with section II–D of appendix B to this part, the lower of the following:

(i) 80 percent of the average yield strength determined by the tensile tests.

(ii) The lowest yield strength determined by the tensile tests.
§ 192.109 Nominal wall thickness (t) for steel pipe.

(a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

(b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in §192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter.

§ 192.111 Design factor (F) for steel pipe.

(a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in §192.105 is determined in accordance with the following table:

<table>
<thead>
<tr>
<th>Class location</th>
<th>Design factor (F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.72</td>
</tr>
<tr>
<td>2</td>
<td>0.60</td>
</tr>
<tr>
<td>3</td>
<td>0.50</td>
</tr>
</tbody>
</table>

(b) A design factor of 0.60 or less must be used in the design formula in §192.105 for steel pipe in Class 1 locations that:

1. Crosses the right-of-way of an unimproved public road, without a casing;
2. Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;
3. Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or
4. Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

(c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in §192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

(d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in §192.105 for—

1. Steel pipe in a compressor station, regulating station, or measuring station; and
2. Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

§ 192.113 Longitudinal joint factor (E) for steel pipe.

The longitudinal joint factor to be used in the design formula in §192.105 is determined in accordance with the following table:

<table>
<thead>
<tr>
<th>Specification</th>
<th>Pipe class</th>
<th>Longitudinal joint factor (E)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASTM A 53</td>
<td>Seamless</td>
<td>1.00</td>
</tr>
<tr>
<td></td>
<td>Electric resistance welded</td>
<td>1.00</td>
</tr>
<tr>
<td></td>
<td>Furnace butt welded</td>
<td>0.60</td>
</tr>
</tbody>
</table>
If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for “Other.”


§ 192.115 Temperature derating factor (T) for steel pipe.

The temperature derating factor to be used in the design formula in §192.105 is determined as follows:

<table>
<thead>
<tr>
<th>Specification</th>
<th>Pipe class</th>
<th>Longitudinal joint factor (E)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASTM A 106</td>
<td>Seamless</td>
<td>1.00</td>
</tr>
<tr>
<td>ASTM A 333/A 333M</td>
<td>Seamless</td>
<td>1.00</td>
</tr>
<tr>
<td>ASTM A 381</td>
<td>Electric resistance welded</td>
<td>1.00</td>
</tr>
<tr>
<td>ASTM A 671</td>
<td>Double submerged arc welded</td>
<td>1.00</td>
</tr>
<tr>
<td>ASTM A 672</td>
<td>Electric-fusion-welded</td>
<td>1.00</td>
</tr>
<tr>
<td>ASTM A 691</td>
<td>Electric-fusion-welded</td>
<td>1.00</td>
</tr>
<tr>
<td>API 5L</td>
<td>Seamless</td>
<td>1.00</td>
</tr>
<tr>
<td></td>
<td>Electric resistance welded</td>
<td>1.00</td>
</tr>
<tr>
<td></td>
<td>Electric flash welded</td>
<td>1.00</td>
</tr>
<tr>
<td></td>
<td>Submerged arc welded</td>
<td>1.00</td>
</tr>
<tr>
<td></td>
<td>Furnace butt welded</td>
<td>1.00</td>
</tr>
<tr>
<td>Other</td>
<td>Pipe over 4 inches (102 millimeters)</td>
<td>.80</td>
</tr>
<tr>
<td>Other</td>
<td>Pipe 4 inches (102 millimeters) or less</td>
<td>.60</td>
</tr>
</tbody>
</table>

For intermediate gas temperatures, the derating factor is determined by interpolation.


§ 192.117 [Reserved]

§ 192.119 [Reserved]

§ 192.121 Design of plastic pipe.

Subject to the limitations of §192.123, the design pressure for plastic pipe is determined in accordance with either of the following formulas:

\[
P = 2S \frac{t}{D - t} 0.32 \\
P = \frac{2S}{(SDR - 1)} 0.32
\]

Where:

- P = Design pressure, gauge, kPa (psig).
- S = For thermoplastic pipe, the long-term hydrostatic strength determined in accordance with the listed specification at a temperature equal to 73°F (23°C), 100°F (38°C), 120°F (49°C), or 140°F (60°C); for reinforced thermosetting plastic pipe, 11,000 psi (75,842 kPa).
- t = Specified wall thickness, mm (in).
- D = Specified outside diameter, mm (in).
- SDR = Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.


§ 192.123 Design limitations for plastic pipe.

(a) The design pressure may not exceed a gauge pressure of 689 kPa (100 psig) for plastic pipe used in:

1. Distribution systems; or
2. Classes 3 and 4 locations.

(b) Plastic pipe may not be used where operating temperatures of the pipe will be:
(1) Below −20°F (−20°C), or −40°F (−40°C) if all pipe and pipeline components whose operating temperature will be below −29°C (−20°F) have a temperature rating by the manufacturer consistent with that operating temperature; or

(2) Above the following applicable temperatures:

(i) For thermoplastic pipe, the temperature at which the long-term hydrostatic strength used in the design formula under §192.121 is determined. However, if the pipe was manufactured before May 18, 1978 and its long-term hydrostatic strength was determined at 73°F (23°C), it may be used at temperatures up to 100°F (38°C).

(ii) For reinforced thermosetting plastic pipe, 150°F (66°C).

(c) The wall thickness for thermoplastic pipe may not be less than 0.062 inches (1.57 millimeters).

(d) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

<table>
<thead>
<tr>
<th>Nominal size in inches (millimeters)</th>
<th>Minimum wall thickness inches (millimeters)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2 (51)</td>
<td>0.060 (1.52)</td>
</tr>
<tr>
<td>3 (76)</td>
<td>0.060 (1.52)</td>
</tr>
<tr>
<td>4 (102)</td>
<td>0.070 (1.8)</td>
</tr>
<tr>
<td>6 (152)</td>
<td>0.100 (2.54)</td>
</tr>
</tbody>
</table>


§ 192.125 Design of copper pipe.

(a) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn.

(b) Copper pipe used in service lines must have wall thickness not less than that indicated in the following table:

<table>
<thead>
<tr>
<th>Standard size inch (millimeter)</th>
<th>Nominal O.D. inch (millimeter)</th>
<th>Wall thickness inch (millimeter)</th>
<th>Nominal</th>
<th>Tolerance</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/4 (13)</td>
<td>.625 (16)</td>
<td>.040 (1.06)</td>
<td>.0035</td>
<td>.0089</td>
</tr>
<tr>
<td>3/8 (16)</td>
<td>.750 (19)</td>
<td>.042 (1.07)</td>
<td>.0035</td>
<td>.0089</td>
</tr>
<tr>
<td>1/2 (19)</td>
<td>.875 (22)</td>
<td>.045 (1.14)</td>
<td>.004</td>
<td>.102</td>
</tr>
<tr>
<td>5/8 (25)</td>
<td>1.000 (25)</td>
<td>.050 (1.27)</td>
<td>.004</td>
<td>.102</td>
</tr>
<tr>
<td>3/4 (32)</td>
<td>1.375 (35)</td>
<td>.055 (1.40)</td>
<td>.0045</td>
<td>.1143</td>
</tr>
<tr>
<td>1 (38)</td>
<td>1.625 (41)</td>
<td>.060 (1.52)</td>
<td>.0045</td>
<td>.1143</td>
</tr>
</tbody>
</table>


Subpart D—Design of Pipeline Components

§ 192.141 Scope.

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

§ 192.143 General requirements.

Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

[Amdt. 48, 49 FR 19824, May 10, 1984]

§ 192.144 Qualifying metallic components.

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in appendix A of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if—

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair...
§ 192.145 Valves.

(a) Except for cast iron and plastic valves, each valve must meet the minimum requirements, or equivalent, of API 6D. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

(b) Each cast iron and plastic valve must comply with the following:

(1) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

(2) The valve must be tested as part of the manufacturing, as follows:

(i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.

(ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.

(iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

(c) Each valve must be able to meet the anticipated operating conditions.

(d) No valve having shell components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if:

(1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i. (7 Mpa) gage; and

(2) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

(e) No valve having pressure containing parts made of ductile iron may be used in the gas pipe components of compressor stations.

[Amdt. 192–45, 48 FR 36639, July 5, 1983]

§ 192.147 Flanges and flange accessories.

(a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5, MSS SP-44, or the equivalent.

(b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

(c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 and be cast integrally with the pipe, valve, or fitting.


§ 192.149 Standard fittings.

(a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

(b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.
§ 192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each line section of a transmission line 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 compressor stations, meter stations, or regulator stations;

(3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

(4) Cross-overs;

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

(6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;

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

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


§ 192.151 Tapping.

(a) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

(b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that:

(1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and

(2) A 1 1/4-inch (32 millimeters) tap may be made in a 4-inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement.

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch (152 millimeters) or larger pipe.


§ 192.153 Components fabricated by welding.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG–101 of section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section 1, section VIII, Division 1, or section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code, except for the following:
§ 192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§ 192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§ 192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§ 192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough supports or anchors to:

1. Prevent undue strain on connected equipment;
2. Resist longitudinal forces caused by a bend or offset in the pipe;
3. Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

1. Free expansion and contraction of the pipeline between supports or anchors may not be restricted.
2. Provision must be made for the service conditions involved.
3. Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

1. A structural support may not be welded directly to the pipe.
2. The support must be provided by a member that completely encircles the pipe.
3. If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.
4. Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.
5. Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header
and the branch to prevent detrimental lateral and vertical movement.


§ 192.163 Compressor stations: Design and construction.

(a) Location of compressor building. Except for a compressor building on a platform located offshore or in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.

(b) Building construction. Each building on a compressor station site must be made of noncombustible materials if it contains either:

(1) Pipe more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure; or

(2) Gas handling equipment other than gas utilization equipment used for domestic purposes.

(c) Exits. Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

(d) Fenced areas. Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

(e) Electrical facilities. Electrical equipment and wiring installed in compressor stations must conform to the National Electrical Code, ANSI/NFPA 70, so far as that code is applicable.


§ 192.165 Compressor stations: Liquid removal.

(a) Where entrained vapors in gas may liquify under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.

(b) Each liquid separator used to remove entrained liquids at a compressor station must:

(1) Have a manually operable means of removing these liquids.

(2) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and

(3) Be manufactured in accordance with section VIII of the ASME Boiler and Pressure Vessel Code, except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

§ 192.167 Compressor stations: Emergency shutdown.

(a) Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:

(1) It must be able to block gas out of the station and blow down the station piping.

(2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.

(3) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except that:

(i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and
§ 192.169 Compressor stations: Pressure limiting devices.
(a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.

(b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

§ 192.171 Compressor stations: Additional safety equipment.
(a) Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

(b) Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

(c) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

(d) Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

e) Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

§ 192.173 Compressor stations: Ventilation.
Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

§ 192.175 Pipe-type and bottle-type holders.
(a) Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe, or in auxiliary equipment, that might cause corrosion or interfere with the safe operation of the holder.

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:
$C=(D \times P \times F)/48.33$  
$C=(3D \times P \times F/1,000)$

in which:

$C$ = Minimum clearance between pipe containers or bottles in inches (millimeters).

$D$ = Outside diameter of pipe containers or bottles in inches (millimeters).

$P$ = Maximum allowable operating pressure, p.s.i. (kPa) gage.

$F$ = Design factor as set forth in §192.111 of this part.


§192.177 Additional provisions for bottle-type holders.

(a) Each bottle-type holder must be—

(1) Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

<table>
<thead>
<tr>
<th>Maximum allowable operating pressure</th>
<th>Minimum clearance feet (meters)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 1,000 p.s.i. (7 MPa) gage</td>
<td>25 (7.6)</td>
</tr>
<tr>
<td>1,000 p.s.i. (7 MPa) gage or more</td>
<td>100 (31)</td>
</tr>
</tbody>
</table>

(2) Designed using the design factors set forth in §192.111; and

(3) Buried with a minimum cover in accordance with §192.327.

(b) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:

(1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A 372/A 372M.

(2) The actual yield-tensile ratio of the steel may not exceed 0.85.

(3) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localized thermit welding process is used.

(4) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.

(5) The holder, connection pipe, and components must be leak tested after installation as required by subpart J of this part.


§192.179 Transmission line valves.

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

(1) Each point on the pipeline in a Class 4 location must be within 2 1/2 miles (4 kilometers) of a valve.

(2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.

(3) Each point on the pipeline in a Class 2 location must be within 7 1/2 miles (12 kilometers) of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

(2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

(d) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow...
§ 192.181 Distribution line valves.

(a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

(b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

(c) Each valve on a main installed for operating or emergency purposes must comply with the following:

1. The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.
2. The operating stem or mechanism must be readily accessible.
3. If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§ 192.183 Vaults: Structural design requirements.

(a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

(b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

(c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inch (254 millimeters), and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.

§ 192.185 Vaults: Accessibility.

Each vault must be located in an accessible location and, so far as practical, away from:

(a) Street intersections or points where traffic is heavy or dense;
(b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and
(c) Water, electric, steam, or other facilities.

§ 192.187 Vaults: Sealing, venting, and ventilation.

Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated as follows:

(a) When the internal volume exceeds 200 cubic feet (5.7 cubic meters):

1. The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;
2. The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and
3. The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

(b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters):

1. If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;
2. If the vault or pit is ventilated, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or
3. If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

(c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings...
§ 192.189 Vaults: Drainage and waterproofing.
(a) Each vault must be designed so as to minimize the entrance of water.
(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.
(c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, ANSI/NFPA 70.


§ 192.191 Design pressure of plastic fittings.
(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517.
(b) Thermoplastic fittings for plastic pipe must conform to ASTM D 2513.


§ 192.193 Valve installation in plastic pipe.
Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

§ 192.195 Protection against accidental overpressuring.
(a) General requirements. Except as provided in §192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§192.199 and 192.201.
(b) Additional requirements for distribution systems. Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—
(1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and
(2) Be designed so as to prevent accidental overpressuring.

§ 192.197 Control of the pressure of gas delivered from high-pressure distribution systems.
(a) If the maximum actual operating pressure of the distribution system is under 60 p.s.i. (414 kPa) gage and a service regulator having the following characteristics is used, no other pressure limiting device is required:
(1) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.
(2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.
(3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.
(4) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.
(5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.
(b) A self-contained service regulator with no external static or control lines.
(b) If the maximum actual operating pressure of the distribution system is 60 p.s.i. (414 kPa) gage, or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of...
§ 192.199 Requirements for design of pressure relief and limiting devices.

Except for rupture discs, each pressure relief or pressure limiting device must:

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

(b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

(d) Have support made of noncombustible material;

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

(g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

§ 192.201 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system:
   (i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;
   (ii) If the maximum allowable operating pressure is 12 p.s.i. (83 kPa) gage or more, but less than 60 p.s.i. (414 kPa) gage, the pressure may not exceed 1.667 times the maximum allowable operating pressure plus 6 p.s.i. (41 kPa) gage; or
   (iii) If the maximum allowable operating pressure is less than 12 p.s.i. (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.


§ 192.203 Instrument, control, and sampling pipe and components.

(a) Applicability. This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

(b) Materials and design. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

(1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

(2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

(3) Brass or copper material may not be used for metal temperatures greater than 400 °F (204 °C).

(4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

(5) Pipe or components in which liquids may accumulate must have drains or drips.

(6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

(7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

(8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

(9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator
§ 192.221 Scope.

(a) This subpart prescribes minimum requirements for welding steel materials in pipelines.

(b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

§ 192.225 Welding—General.

(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify the 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.

[Amdt. 192–52, 51 FR 20297, June 4, 1986]

§ 192.227 Qualification of welders.

(a) Except as provided in paragraph (b) of this section, each welder must be qualified in accordance with section 3 of API Standard 1104 or section IX of the ASME Boiler and Pressure Vessel Code. However, a welder qualified under an earlier edition than listed in appendix A may weld but may not requalify under that earlier edition.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under section 3 or 6 of API Standard 1104, except that a welder qualified under an earlier edition previously listed in Appendix A of this part may weld but may not requalify under that earlier edition; and

(1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under sections III of Appendix C of this part.

(2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder is tested in accordance with paragraph (c)(1) of this section or requalifies under paragraph (d)(1) or (d)(2) of this section.

(d) A welder qualified under § 192.227(b) may not weld unless—

(1) Within the preceding 15 calendar months, but at least once each calendar year, the welder has requalified under § 192.227(b); or

(2) Within the preceding 7½ calendar months, but at least twice each calendar year, the welder has had—

(i) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

(ii) For welders who work only on service lines 2 inches (51 millimeters) or smaller in diameter, two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

§ 192.231 Protection from weather.
    The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

§ 192.233 Miter joints.
    (a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3°.
    (b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than $12\frac{1}{2}$° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.
    (c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°.

§ 192.235 Preparation for welding.
    Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

§ 192.241 Inspection and test of welds.
    (a) Visual inspection of welding must be conducted to insure that:
        (1) The welding is performed in accordance with the welding procedure; and
        (2) The weld is acceptable under paragraph (c) of this section.
    (b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with §192.233, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if:
        (1) The pipe has a nominal diameter of less than 6 inches (152 millimeters); or
        (2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.
    (c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 6 of API Standard 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if the Appendix to API Standard 1104 applies to the weld, the acceptability of the weld may be further determined under that Appendix.


§ 192.243 Nondestructive testing.
    (a) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.
    (b) Nondestructive testing of welds must be performed:
        (1) In accordance with written procedures; and
        (2) By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.
    (c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under §192.241(c).
    (d) When nondestructive testing is required under §192.241(b), the following percentages of each day’s field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:
        (1) In Class 1 locations, except offshore, at least 10 percent.
        (2) In Class 2 locations, at least 15 percent.
        (3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impractical, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

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§ 192.245 Repair or removal of defects.

(a) Each weld that is unacceptable under §192.241(c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline 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 §192.225. 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.


Subpart F—Joining of Materials Other Than by Welding

§ 192.271 Scope.

(a) This subpart prescribes minimum requirements for joining materials in pipelines, other than by welding.

(b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.

§ 192.273 General.

(a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

(c) Each joint must be inspected to insure compliance with this subpart.

§ 192.275 Cast iron pipe.

(a) Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

(b) Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

(c) Cast iron pipe may not be joined by threaded joints.

(d) Cast iron pipe may not be joined by brazing.


§ 192.277 Ductile iron pipe.

(a) Ductile iron pipe may not be joined by threaded joints.

(b) Ductile iron pipe may not be joined by brazing.

§ 192.279 Copper pipe.

Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.


§ 192.281 Plastic pipe.

(a) General. A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) Solvent cement joints. Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM Designation D 2513.

(c) Heat-fusion joints. Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

(d) Adhesive joints. Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM Designation D 2517.

(2) The materials and adhesive must be compatible with each other.

(e) Mechanical joints. Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

§ 192.283 Plastic pipe: qualifying joining procedures.

(a) Heat fusion, solvent cement, and adhesive joints. Before any written procedure established under §192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Pressure (Quick Burst)) of ASTM D 2513;

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517; or

(iii) In the case of electrofusion fittings for polyethylene pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM Designation F1055.

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for non-lateral pipe connections, follow the

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

   (i) Tested under any one of the test methods listed under §192.283(a) applicable to the type of joint and material being tested;

   (ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

   (iii) Cut into at least 3 longitudinal straps, each of which is:

       (A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

       (B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be requalified under an applicable procedure, if during any 12-month period that person:

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under §192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in
§ 192.287 Plastic pipe: inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by §§ 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

[Amtd. 192-34, 44 FR 42974, July 23, 1979]

Subpart G—General Construction Requirements for Transmission Lines and Mains

§ 192.301 Scope.

This subpart prescribes minimum requirements for constructing transmission lines and mains.

§ 192.303 Compliance with specifications or standards.

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this part.

§ 192.305 Inspection: General.

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

§ 192.307 Inspection of materials.

Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

§ 192.309 Repair of steel pipe.

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

(1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

(1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.

(2) A dent that affects the longitudinal weld or a circumferential weld.

(3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:

(i) More than ¼ inch (6.4 millimeters) in pipe 12 ¾ inches (324 millimeters) or less in outer diameter; or

(ii) More than 2 percent of the nominal pipe diameter in pipe over 12 ¾ inches (324 millimeters) in outer diameter.

For the purpose of this section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:

(1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

(e) Each gouge, groove, arc burn, or dent that is removed from a length of
§ 192.311 Repair of plastic pipe.
Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired by a patching saddle or removed.

§ 192.313 Bends and elbows.
(a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with §192.315, 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 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.
   (b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be non-destructively tested either before or after the bending process.
   (c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).

§ 192.315 Wrinkle bends in steel pipe.
(a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.
   (b) Each wrinkle bend on steel pipe must comply with the following:
      (1) The bend must not have any sharp kinks.
      (2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.
      (3) On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than 1½° for each wrinkle.
      (4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

§ 192.317 Protection from hazards.
(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.
   (b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.
   (c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

§ 192.319 Installation of pipe in a ditch.
(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.
   (b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:
§ 192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water is to be installed so that the top of the pipe is 36 inches (0.914 meters) below the seabed for normal excavation or 18 inches (0.457 meters) for rock excavation.

[b]§ 192.321 Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level unless otherwise permitted by paragraph (g) of this section.

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

(d) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inch (2.29 millimeters), except that pipe with an outside diameter of 0.875 inch (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inch (1.58 millimeters).

(e) Plastic pipe that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground.

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

(g) Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

(1) The operator must be able to demonstrate that the cumulative above-ground exposure of the pipe does not exceed the manufacturer’s recommended maximum period of exposure of 2 years, whichever is less.

(2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

(3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.


§ 192.323 Casing.

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibility of water entering the casing, the ends must be sealed.

(c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.

(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

§ 192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraph (a) or (b) of...
§ 192.327 Cover.

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line or main must be installed with a minimum cover as follows:

<table>
<thead>
<tr>
<th>Location</th>
<th>Normal soil</th>
<th>Consolidated rock</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class 1 locations</td>
<td>30 (762)</td>
<td>18 (457)</td>
</tr>
<tr>
<td>Class 2, 3, and 4 locations</td>
<td>36 (914)</td>
<td>24 (610)</td>
</tr>
<tr>
<td>Drainage ditches of public roads</td>
<td>36 (914)</td>
<td>24 (610)</td>
</tr>
<tr>
<td>and railroad crossings</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:

(1) Establishes a minimum cover of less than 24 inches (610 millimeters);
(2) Requires that mains be installed in a common trench with other utility lines; and
(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

(f) All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows:

(1) Except as provided in paragraph (c) of this section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

(2) Pipe under water at least 12 feet (3.66 meters) deep must be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

(g) All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in §192.3, must be installed in accordance with §192.612(b)(3).

§ 192.327 Cover.

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line or main must be installed with a minimum cover as follows:

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:

(1) Establishes a minimum cover of less than 24 inches (610 millimeters);
(2) Requires that mains be installed in a common trench with other utility lines; and
(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

(f) All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows:

(1) Except as provided in paragraph (c) of this section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

(2) Pipe under water at least 12 feet (3.66 meters) deep must be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

(g) All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in §192.3, must be installed in accordance with §192.612(b)(3).

Subpart H—Customer Meters, Service Regulators, and Service Lines

§ 192.351 Scope.

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

§ 192.353 Customer meters and regulators: Location.

(a) Each meter and service regulator, whether inside or outside of a building, must be installed in a readily accessible location and be protected from corrosion and other damage. However, the upstream regulator in a series may be buried.

(b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

(c) Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914
millimeters) from any source of ignition or any source of heat which might damage the meter.

(d) Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.


§ 192.355 Customer meters and regulators: Protection from damage.

(a) Protection from vacuum or back pressure. If the customer’s equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.

(b) Service regulator vents and relief vents. Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must—

(1) Be rain and insect resistant;

(2) Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and

(3) Be protected from damage caused by submergence in areas where flooding may occur.

(c) Pits and vaults. Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic.


§ 192.357 Customer meters and regulators: Installation.

(a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

(b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this part.

(c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

(d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

§ 192.359 Customer meter installations: Operating pressure.

(a) A meter may not be used at a pressure that is more than 67 percent of the manufacturer’s shell test pressure.

(b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i. (69 kPa) gage.

(c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.


§ 192.361 Service lines: Installation.

(a) Depth. Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) Support and backfill. Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) Grading for drainage. Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

(d) Protection against piping strain and external loading. Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) Installation of service lines into buildings. Each underground service line installed below grade through the outer foundation wall of a building must:

(1) In the case of a metal service line, be protected against corrosion;

(2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and
§ 192.363 Service lines: Valve requirements.

(a) Each service line must have a service-line valve that meets the applicable requirements of subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

(b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

§ 192.365 Service lines: Location of valves.

(a) Relation to regulator or meter. Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

(b) Outside valves. Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.

(c) Underground valves. Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

§ 192.367 Service lines: General requirements for connections to main piping.

(a) Location. Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

(b) Compression-type connection to main. Each compression-type service line to main connection must:

1. Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and
2. If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

§ 192.369 Service lines: Connections to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of §192.273.

(b) If a threaded tap is being inserted, the requirements of §192.151 (b) and (c) must also be met.

§ 192.371 Service lines: Steel.

Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.

§ 192.373 Service lines: Cast iron and ductile iron.

(a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.
§ 192.381 Service lines: Excess flow valve performance standards.

(a) Excess flow valves to be used on single residence service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer’s written specification, to ensure that each valve will:

(1) Function properly up to the maximum operating pressure at which the valve is rated;

(2) Function properly at all temperatures reasonably expected in the operating environment of the service line;

(3) At 10 p.s.i. (69 kPa) gage:

   (i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

   (ii) Upon closure, reduce gas flow—

       (A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer’s specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

       (B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

(4) Not close when the pressure is less than the manufacturer’s minimum specified operating pressure and the flow rate is below the manufacturer’s minimum specified closure flow rate.

(b) An excess flow valve must meet the applicable requirements of Subparts B and D of this part.

(c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

(d) An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

(e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance.

§ 192.379 New service lines not in use.

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

(a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(c) The customer’s piping must be physically disconnected from the gas supply and the open pipe ends sealed.

[Amdt. 192-8, 37 FR 20694, Oct. 3, 1972]
§ 192.383 Excess flow valve customer notification.

(a) Definitions. As used in this section:

Costs associated with installation means the costs directly connected with installing an excess flow valve, for example, costs of parts, labor, inventory and procurement. It does not include maintenance and replacement costs until such costs are incurred.

Replaced service line means a natural gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

Service line customer means the person who pays the gas bill, or where service has not yet been established, the person requesting service.

(b) Which customers must receive notification. Notification is required on each newly installed service line or replaced service line that operates continuously throughout the year at a pressure not less than 68.9 kPa (10 psig) and that serves a single residence. On these lines an operator of a natural gas distribution system must notify the service line customer once in writing.

(c) What to put in the written notice. (1) An explanation for the customer that an excess flow valve meeting the performance standards prescribed under §192.381 is available for the operator to install if the customer bears the costs associated with installation;

(2) An explanation for the customer of the potential safety benefits that may be derived from installing an excess flow valve. The explanation must include that an excess flow valve is designed to shut off flow of natural gas automatically if the service line breaks;

(3) A description of installation, maintenance, and replacement costs. The notice must explain that if the customer requests the operator to install an EFV, the customer bears all costs associated with installation, and what those costs are. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be, to the extent known.

(d) When notification and installation must be made. (1) After February 3, 1999 an operator must notify each service line customer set forth in paragraph (b) of this section:

(i) On new service lines when the customer applies for service.

(ii) On replaced service lines when the operator determines the service line will be replaced.

(2) If a service line customer requests installation an operator must install the EFV at a mutually agreeable date.

(e) What records are required. (1) An operator must make the following records available for inspection by the Administrator or a State agency participating under 49 U.S.C. 60105 or 60106:

(i) A copy of the notice currently in use; and

(ii) Evidence that notice has been sent to the service line customers set forth in paragraph (b) of this section, within the previous three years.

(2) [Reserved]

(f) When notification is not required. The notification requirements do not apply if the operator can demonstrate—

(1) That the operator will voluntarily install an excess flow valve or that the state or local jurisdiction requires installation;

(2) That excess flow valves meeting the performance standards in §192.381 are not available to the operator;

(3) That the operator has prior experience with contaminants in the gas stream that could interfere with the operation of an excess flow valve, cause loss of service to a residence, or interfere with necessary operation or maintenance activities, such as blowing liquids from the line.

(4) That an emergency or short time notice replacement situation made it impractical for the operator to notify a service line customer before replacing a service line. Examples of these situations would be where an operator has to replace a service line quickly because of—

(i) Third party excavation damage;

(ii) Grade 1 leaks as defined in the Appendix G-192-11 of the Gas Piping
Subpart I—Requirements for Corrosion Control

§ 192.451 Scope.

(a) This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

(b) [Reserved]

§ 192.452 Applicability to converted pipelines.

Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with §192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after completion of construction. However, requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

§ 192.453 General.

The corrosion control procedures required by §192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

§ 192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

1. It must have an external protective coating meeting the requirements of §192.461.

2. It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that—

1. For a copper pipeline, a corrosive environment does not exist; or

2. For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must...
§ 192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

(1) Bare or ineffectively coated transmission lines.

(2) Bare or coated pipes at compressor, regulator, and measuring stations.

(3) Bare or coated distribution lines.

The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

(c) For the purpose of this subpart, active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.

§ 192.459 External corrosion control: Examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under §§ 192.483 through 192.489 is found, the operator shall 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.

§ 192.461 External corrosion control: Protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—

(1) Be applied on a properly prepared surface;

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil stress; and

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.
(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

§192.463 External corrosion control: Cathodic protection.

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential—

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of appendix D of this part for amphoteric metals.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

§192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) Each cathodic protection rectifier or other impressed power source must be inspected six times each calendar year, but with intervals not exceeding 2½ months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by paragraphs (b) and (c) of §192.455 and paragraph (b) of §192.457, each operator shall, at intervals not exceeding 3 years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.


§192.467 External corrosion control: Electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.
§ 192.469 External corrosion control: Test stations.

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

§ 192.471 External corrosion control: Test leads.

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

§ 192.473 External corrosion control: Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

§ 192.475 Internal corrosion control: General.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m³) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.

§ 192.477 Internal corrosion control: Monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means
§ 192.485 Remedial measures: General.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of §192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

§ 192.485 Remedial measures: Transmission lines.

(a) General corrosion. Each segment of transmission line pipe with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) Localized corrosion pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3–805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the...
§ 192.487 Remedial measures: Distribution lines other than cast iron or ductile iron lines.

(a) General corrosion. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) Localized corrosion pitting. Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

§ 192.489 Remedial measures: Cast iron and ductile iron pipelines.

(a) General graphitization. Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced.

(b) Localized graphitization. Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

§ 192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. 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.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

[Amtd. 192–78, 61 FR 28785, June 6, 1996]

Subpart J—Test Requirements

§ 192.501 Scope.

This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

§ 192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

(1) It has been tested in accordance with this subpart and §192.619 to substantiate the maximum allowable operating pressure; and

(2) Each potentially hazardous leak has been located and eliminated.

(b) The test medium must be liquid, air, natural gas, or inert gas that is—

(1) Compatible with the material of which the pipeline is constructed;

(2) Relatively free of sedimentary materials; and

(3) Except for natural gas, nonflammable.

(c) Except as provided in §192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

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<tr>
<th>Class location</th>
<th>Maximum hoop stress allowed as percentage of SMYS</th>
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</thead>
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<td>Natural gas</td>
<td>Air or inert gas</td>
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<td>80</td>
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<tr>
<td>2</td>
<td>30</td>
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</table>
(d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.

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<thead>
<tr>
<th>Class location</th>
<th>Maximum hoop stress allowed as percentage of SMYS</th>
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<tbody>
<tr>
<td></td>
<td>Natural gas</td>
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<tr>
<td>3</td>
<td>30</td>
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<tr>
<td>4</td>
<td>30</td>
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</tbody>
</table>

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

(a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium—

(1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or

(2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.

(c) The pressure must be maintained at or above the test pressure for at least 1 hour.

§ 192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (689 kPa) gage must be leak tested in accordance with the following:

(a) The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) Each main that is to be operated at less than 1 p.s.i. (6.9 kPa) gage must be tested to at least 10 p.s.i. (69 kPa) gage and each main to be operated at or above 1 p.s.i. (6.9 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage.


§ 192.511 Test requirements for service lines.

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i. (6.9 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage, except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with §192.507 of this subpart.


§ 192.513 Test requirements for plastic pipelines.

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

(b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.

(c) The test pressure must be at least 150 percent of the maximum operating pressure or 50 p.s.i. (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than three times the pressure determined under §192.121, at a temperature not less than the pipe temperature during the test.

(d) During the test, the temperature of thermoplastic material may not be more than 100°C (38°F), or the temperature at which the material’s long-term hydrostatic strength has been determined under the listed specification, whichever is greater.


§ 192.515 Environmental protection and safety requirements.

(a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

§ 192.517 Records.

Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§192.505 and 192.507. The record must contain at least the following information:

(a) The operator’s name, the name of the operator’s employee responsible for making the test, and the name of any test company used.

(b) Test medium used.

(c) Test pressure.

(d) Test duration.
(e) Pressure recording charts, or other record of pressure readings.
(f) Elevation variations, whenever significant for the particular test.
(g) Leaks and failures noted and their disposition.

Subpart K—Uprating

§ 192.551 Scope.
This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

§ 192.553 General requirements.
(a) Pressure increases. Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

(1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.
(2) Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

(b) Records. Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this subpart, of all work performed, and of each pressure test conducted, in connection with the uprating.

(c) Written plan. Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.

(d) Limitation on increase in maximum allowable operating pressure. Except as provided in §192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under this part for a new segment of pipeline constructed of the same materials in the same location.

§ 192.555 Uprating to a pressure that will produce a hoop stress of 30 percent or more of SMYS in steel pipelines.

(a) Unless the requirements of this section have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of SMYS and that is above the established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall:

(1) Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this part; and

(2) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

(c) After complying with paragraph (b) of this section, an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under §192.619, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

(d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:

(1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.

(2) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1
§ 192.557 Location if the line has not previously been tested, and if:

(i) It is impractical to test it in accordance with the requirements of this part;

(ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and

(iii) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this part.

e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d)(2) of this section, the increase in pressure must be made in increments that are equal to:

(1) 10 percent of the pressure before the uprating; or

(2) 25 percent of the total pressure increase, whichever produces the fewer number of increments.

§ 192.557 Uprating: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS: plastic, cast iron, and ductile iron pipelines.

(a) Unless the requirements of this section have been met, no person may subject:

(1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or

(2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

(1) Review the design, operating, and maintenance history of the segment of pipeline;

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;

(3) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;

(4) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation;

(5) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

(6) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.

(c) After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i. (69 kPa) gage or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)(6) of this section apply, there must be at least two approximately equal incremental increases.

(d) If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:

(1) In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill.

(2) Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least
three places where the cover is most likely to be greatest and shall use the greatest cover measured.

(3) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

<table>
<thead>
<tr>
<th>Pipe size inches (millimeters)</th>
<th>Cast iron pipe Allowance inches (millimeters)</th>
<th>Centrifugally cast pipe Allowance inches (millimeters)</th>
<th>Ductile iron pipe Allowance inches (millimeters)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3 to 8 (76 to 203)</td>
<td>0.075 (1.91)</td>
<td>0.065 (1.65)</td>
<td>0.065 (1.65)</td>
</tr>
<tr>
<td>10 to 12 (254 to 305)</td>
<td>0.08 (2.03)</td>
<td>0.07 (1.78)</td>
<td>0.07 (1.78)</td>
</tr>
<tr>
<td>14 to 24 (356 to 610)</td>
<td>0.08 (2.03)</td>
<td>0.08 (2.03)</td>
<td>0.075 (1.91)</td>
</tr>
<tr>
<td>30 to 42 (762 to 1067)</td>
<td>0.09 (2.29)</td>
<td>0.09 (2.29)</td>
<td>0.075 (1.91)</td>
</tr>
<tr>
<td>48 (1219)</td>
<td>0.09 (2.29)</td>
<td>0.09 (2.29)</td>
<td>0.08 (2.03)</td>
</tr>
<tr>
<td>54 to 60 (1372 to 1524)</td>
<td>0.10 (2.54)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(4) For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 p.s.i. (76 MPa) gage and a modulus of rupture of 31,000 p.s.i. (214 MPa) gage.


Subpart L—Operations

§ 192.601 Scope.

This subpart prescribes minimum requirements for the operation of pipeline facilities.

§ 192.603 General provisions.

(a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart.

(b) Each operator shall keep records necessary to administer the procedures established under §192.605.

(c) 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.


§ 192.605 Procedural manual for operations, maintenance, and emergencies.

(a) General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

(b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part.
§ 192.605  

(2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

(3) Making construction records, maps, and operating history available to appropriate operating personnel.

(4) Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner.

(5) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.

(6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

(7) Starting, operating and shutting down gas compressor units.

(8) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.

(9) 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.

(10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including—

(i) Provision for detecting external corrosion before the strength of the container has been impaired;

(ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

(iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.

(c) Abnormal operation. For transmission lines, 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; and

(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in 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) Notifying responsible operator personnel when notice of an abnormal operation is received.

(4) 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.

(5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.

(d) 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 §191.23 of this subchapter.

(e) Surveillance, emergency response, and accident investigation. The procedures required by §§192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

§ 192.609 Change in class location: Required study.
Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(a) The present class location for the segment involved.
(b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.
(c) The physical condition of the segment to the extent it can be ascertained from available records;
(d) The operating and maintenance history of the segment;
(e) The maximum actual operating pressure and the corresponding hoop stress, taking pressure gradient into account, for the segment of pipeline involved;
(f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

§ 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours, the maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§ 192.553 and 192.555.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under § 192.609 must be completed within 18 months of the change in class location. Pressure reduction under paragraph (a)(1) or (2) of this section within the 18-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

§ 192.612 Underwater inspection and re-burial of pipelines in the Gulf of Mexico and its inlets.
(a) Each operator shall, in accordance with this section, conduct an underwater inspection of its pipelines in the Gulf of Mexico and its inlets. The inspection must be conducted after October 3, 1989 and before November 16, 1992.
(b) If, as a result of an inspection under paragraph (a) of this section, or upon notification by any person, an operator discovers that a pipeline it operates is exposed on the seabed or constitutes 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 the discovery is made, place the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.


§ 192.613 Continuing surveillance.
(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.
(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to re-condition or phase out the segment involved, or, if the segment cannot be re-conditioned or phased out, reduce the maximum allowable operating pressure in accordance with §192.619 (a) and (b).

§ 192.614 Damage prevention program.
(a) Except as provided in paragraphs (d) and (e) of this section, each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purposes of this section, the term “excavation activities” includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving 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

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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 possible, 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, other than those located offshore, in Class 1 or 2 locations until September 20, 1995.

(3) Pipelines to which access is physically controlled by the operator.

(e) Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following:

(1) The requirement of paragraph (a) of this section that the damage prevention program be written; and

(2) The requirements of paragraphs (c)(1) and (c)(2) of this section.


§192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

(3) Prompt and effective response to a notice of each type of emergency, including the following:
   (i) Gas detected inside or near a building.
   (ii) Fire located near or directly involving a pipeline facility.
   (iii) Explosion occurring near or directly involving a pipeline facility.
   (iv) Natural disaster.

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

(5) Actions directed toward protecting people first and then property.

(6) Emergency shutdown and pressure reduction in any section of the operator’s pipeline system necessary to minimize hazards to life or property.

(7) Making safe any actual or potential hazard to life or property.

(8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.

(9) Safely restoring any service outage.

(10) Beginning action under §192.617, if applicable, as soon after the end of the emergency as possible.
§ 192.616 Public education.

Each operator shall establish a continuing educational program to enable customers, the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a gas pipeline emergency for the purpose of reporting it to the operator or the appropriate public officials. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas. 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.

[Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]

§ 192.617 Investigation of failures.

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) Except as provided in paragraph (c) of this section, no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is 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 factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 12 3⁄4 inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

<table>
<thead>
<tr>
<th>Class</th>
<th>Factors</th>
<th>Converted under §192.14</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.1</td>
<td>1.1</td>
</tr>
<tr>
<td>2</td>
<td>1.25</td>
<td>1.25</td>
</tr>
<tr>
<td>3</td>
<td>1.4</td>
<td>1.5</td>
</tr>
</tbody>
</table>

[Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]
§ 192.625 Odorization of gas.

(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the

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<table>
<thead>
<tr>
<th>Class location</th>
<th>Factors 1, segment—</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Installed</td>
</tr>
<tr>
<td></td>
<td>before (Nov. 12, 1970)</td>
</tr>
<tr>
<td>4</td>
<td>1.4</td>
</tr>
</tbody>
</table>

1 For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970 (or in the case of offshore gathering lines, July 1, 1976), unless the segment was tested in accordance with paragraph (a)(2) of this section after July 1, 1965 (or in the case of offshore gathering lines, July 1, 1971), or the segment was uprated in accordance with subpart K of this part.

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

(b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970, or in the case of offshore gathering lines, July 1, 1976, subject to the requirements of §192.611.

§ 192.627

lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:

(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975:

(i) An underground storage field;

(ii) A gas processing plant;

(iii) A gas dehydration plant; or

(iv) An industrial plant using gas in a process where the presence of an odorant:

(A) Makes the end product unfit for the purpose for which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction;

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or

(4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

(c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

(1) The odorant may not be deleterious to persons, materials, or pipe.

(2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

(d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(f) Each operator shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section. Operators of master meter systems may comply with this requirement by—

(1) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

(2) Conducting periodic “sniff” tests at the extremities of the system to confirm that the gas contains odorant.

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For Federal Register citations affecting §192.625, see the List of CFR Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access.

§ 192.627 Tapping pipelines under pressure.

Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

§ 192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

Subpart M—Maintenance

§ 192.701 Scope.

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

§ 192.703 General.

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.

(b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

(c) Hazardous leaks must be repaired promptly.
§ 192.705 Transmission lines: Patrolling.

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

(b) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

<table>
<thead>
<tr>
<th>Class location of line</th>
<th>At highway and railroad crossings</th>
<th>At all other places</th>
</tr>
</thead>
<tbody>
<tr>
<td>1, 2</td>
<td>7 1/2 months; at least twice each calendar year</td>
<td>15 months; at least once each calendar year</td>
</tr>
<tr>
<td>3</td>
<td>4 1/2 months; at least four times each calendar year</td>
<td>7 1/2 months; at least twice each calendar year</td>
</tr>
<tr>
<td>4</td>
<td>4 1/2 months; at least four times each calendar year</td>
<td>4 1/2 months; at least four times each calendar year</td>
</tr>
</tbody>
</table>

(c) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

[Amtd. 192-21, 40 FR 20283, May 9, 1975, as amended by Amtd. 192-43, 47 FR 48851, Oct. 21, 1982; Amtd. 192-78, 61 FR 28786, June 6, 1996]

§ 192.706 Transmission lines: Leakage surveys.

Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with §192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted—

(a) In Class 3 locations, at intervals not exceeding 7 1/2 months, but at least twice each calendar year; and

(b) In Class 4 locations, at intervals not exceeding 4 1/2 months, but at least four times each calendar year.


§ 192.707 Line markers for mains and transmission lines.

(a) Buried pipelines. Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:

(1) At each crossing of a public road and railroad; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

(b) Exceptions for buried pipelines. Line markers are not required for the following pipelines:

(1) Mains and transmission lines located offshore, or at crossings of or under waterways and other bodies of water.

(2) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under §192.614.

(3) Transmission lines in Class 3 or 4 locations until March 20, 1996.

(4) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.

(c) Pipelines aboveground. Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

(d) Marker warning. The following must be written legibly on a background of sharply contrasting color on each line marker:

(1) The word “Warning,” “Caution,” or “Danger” followed by the words “Gas (or name of gas transported) Pipeline” all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with 1 1/4 inch (6.4 millimeters) stroke.

(2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

§ 192.709 Transmission lines: Record keeping.

Each operator shall maintain the following records for transmission lines for the periods specified:

(a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.

(b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section.

(c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

[Amdt. 192–78, 61 FR 28786, June 6, 1996]

§ 192.711 Transmission lines: General requirements for repair procedures.

(a) Each operator shall take immediate temporary measures to protect the public whenever:

(1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of SMYS; and

(2) It is not feasible to make a permanent repair at the time of discovery.

As soon as feasible, the operator shall make permanent repairs.

(b) Except as provided in §192.717(b)(3), no operator may use a welded patch as a means of repair.


§ 192.713 Transmission lines: Permanent field repair of imperfections and damages.

(a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(b) Operating pressure must be at a safe level during repair operations.


§ 192.715 Transmission lines: Permanent field repair of welds.

Each weld that is unacceptable under §192.241(c) must be repaired as follows:

(a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of §192.245.

(b) A weld may be repaired in accordance with §192.245 while the segment of transmission line is in service if:

(1) The weld is not leaking;

(2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and

(3) Grinding of the defective area can be limited so that at least 3/8-inch (3.2 millimeters) thickness in the pipe weld remains.

(c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.


§ 192.717 Transmission lines: Permanent field repair of leaks.

Each permanent field repair of a leak on a transmission line must be made by—

(a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or

(b) Repairing the leak by one of the following methods:

(1) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS.

(2) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp.

(3) If the leak is due to a corrosion pit on pipe of not more than 40,000 psi (267 Mpa) SMYS, fillet weld over
§ 192.719 Transmission lines: Testing of repairs.

(a) Testing of replacement pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

(b) Testing of repairs made by welding. Each repair made by welding in accordance with §§ 192.713, 192.715, and 192.717 must be examined in accordance with §192.241.


§ 192.721 Distribution systems: Patrolling.

(a) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.

(b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—

(1) In business districts, at intervals not exceeding 4\(\frac{1}{2}\) months, but at least four times each calendar year; and

(2) Outside business districts, at intervals not exceeding 7\(\frac{1}{2}\) months, but at least twice each calendar year.


§ 192.727 Abandonment or deactivation of facilities.

(a) Each operator shall conduct abandonment or deactivation of pipelines in
§ 192.727  
accordance with the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(3) The customer’s piping must be physically disconnected from the supply and the open pipe ends sealed.

(e) If air is used for purging, the operator shall assure that a combustible mixture is not present after purging.

(f) Each abandoned vault must be filled with a suitable compacted material.

(g) 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.

(1) 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.rspa.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 Information Officer, Research and Special Programs Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366–4566; e-mail, roger.little@rspa.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.

(2) Data on pipeline facilities abandoned before October 10, 2000 must be filed by before April 10, 2001. Operators may submit reports by mail, fax or e-mail to the Information Officer, Research and Special Programs Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366–4566; e-mail, roger.little@rspa.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.
§ 192.741 Pressure limiting and regulating stations: Telemetering or recording gauges.

(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gauges to indicate the gas pressure in the district.

(b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

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.

§ 192.731 Compressor stations: Inspection and testing of relief devices.

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

(c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

§ 192.735 Compressor stations: Storage of combustible materials.

(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

(b) Aboveground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30.

§ 192.736 Compressor stations: Gas detection.

(a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is—

(1) Constructed so that at least 50 percent of its upright side area is permanently open; or

(2) Located in an unattended field compressor station of 1,000 horsepower (746 kW) or less.

(b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section, each gas detection and alarm system required by this section must—

(1) Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and

(2) If that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.

(c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

§ 192.739 Pressure limiting and regulating stations: Inspection and testing.

Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

(a) In good mechanical condition;

(b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(c) Set to function at the correct pressure; and

(d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

§ 192.741 Pressure limiting and regulating stations: Telemetering or recording gauges.
§ 192.743 Pressure limiting and regulating stations: Testing of relief devices.

(c) If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

§ 192.743 Pressure limiting and regulating stations: Testing of relief devices.

(a) If feasible, pressure relief devices (except rupture discs) must be tested in place, at intervals not exceeding 15 months, but at least once each calendar year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made at intervals not exceeding 15 months, but at least once each calendar year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works. After the initial calculations, subsequent calculations are not required if the review documents that parameters have not changed in a manner which would cause the capacity to be less than required.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.


§ 192.749 Vault maintenance.

(a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.

(b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

(d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.


§ 192.751 Prevention of accidental ignition.

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

(b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

(c) Post warning signs, where appropriate.

§ 192.753 Caulked bell and spigot joints.

(a) Each cast-iron caulked bell and spigot joint that is subject to pressures of 25 p.s.i. (172 kPa) gage or more must be sealed with:

(1) A mechanical leak clamp; or

(2) A material or device which:

(i) Does not reduce the flexibility of the joint;
(ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§192.53 (a) and (b) and 192.143.

(b) Each cast iron caulked bell and spigot joint that is subject to pressures of less than 25 p.s.i. (172 kPa) gage and is exposed for any reason, must be sealed by a means other than caulking.

§192.755 Protecting cast-iron pipelines.

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

1. Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;
2. Impact forces by vehicles;
3. Earth movement;
4. Apparent future excavations near the pipeline; or
5. Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of §§192.317(a), 192.319, and 192.361(b)–(d).

§192.805 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 incident as defined in Part 191;
§ 192.807 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.

§ 192.809 General.

(a) Operators must have a written qualification program by April 27, 2001.

(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 those covered tasks; and

(g) Identify those covered tasks and the intervals at which evaluation of the individual’s qualifications is needed.

§ 192.807 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.

§ 192.809 General.

(a) Operators must have a written qualification program by April 27, 2001.

(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 28, 1999.

(d) After October 28, 2002, work performance history may not be used as a sole evaluation method.


APPENDIX A TO PART 192—
INTEGRATED SYSTEMS

I. List of Organizations and Addresses

A. American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.

B. American National Standards Institute (ANSI), 11 West 42nd Street, New York, NY 10036.

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

D. The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, NY 10017.

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

F. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSSS), 127 Park Street, NW., Vienna, VA 22180.

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

II. Documents Incorporated by Reference (Numbers in Parentheses Indicate Applicable Editions)

A. American Gas Association (AGA):


B. American Petroleum Institute (API):


(2) API Recommended Practice 5L1, “Recommended Practice for Pipeline Valves (Gate, Plug, Ball, and Check Valves)” (21st edition, 1994).


C. American Society for Testing and Materials (ASTM):


Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures” (A 691–93).


D. The American Society of Mechanical Engineers (ASME):


E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):


2. [Reserved]

F. National Fire Protection Association (NFPA):


APPENDIX B TO PART 192—
QUALIFICATION OF PIPE

I. Listed Pipe Specifications (Numbers in Parentheses Indicate Applicable Editions)

API 5L—Steel pipe (1995).


ASTM A 671—Steel pipe (1994).

ASTM A 672—Steel pipe (1994).


ASTM D 2513—Thermosetting plastic pipe and tubing (1994).

II. Steel pipe of unknown or unlisted specification.

A. Bending Properties. For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53, except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. Weldability. A girth weld must be made in the pipe by a welder who is qualified under subpart E of this part. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 400 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 100 lengths of pipe. The weld must be tested in accordance with API Standard 1104. If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code. The same number of chemical tests

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must be made as are required for testing a girth weld.

C. Inspection. The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

The edition of the listed specification under which the pipe was manufactured must have the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

(2) The pipe must be tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

EDITORIAL NOTE: For Federal Register citations affecting appendix B of part 192, see the List of CFR Sections Affected in the Finding Aids section of this volume.

APPENDIX C TO PART 192—QUALIFICATION OF WELDERS FOR LOW STRESS LEVEL PIPE

I. Basic test. The test is made on pipe 12 inches (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than 1⁄4-inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered.

II. Additional tests for welders of service line connections to mains. A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. Periodic tests for welders of small service lines. Two samples of the welder’s work, each about 8 inches (200 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

(1) One sample is centered in a guided bend testing machine and bent to the contour of
the die for a distance of 2 inches (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

(2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test described in subparagraph (1) of this paragraph.

(3) A negative (cathodic) polarization voltage shift of at least 300 millivolts. Determination of this polarization voltage shift must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.

(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

C. Copper structures. A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. Metals of different anodic potentials. A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. Interpretation of voltage measurement. Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of section I of this appendix.

III. Determination of polarization voltage shift. The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(3), B(2), and C of section I of this appendix.

IV. Reference half cells. A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two commonly used reference half cells are listed below along with their applications.

1. Copper structures.

The above criteria must be determined in accordance with sections III and IV of this appendix.

APPENDIX D to PART 192—CRITERIA FOR CATHODIC PROTECTION AND DETERMINATION OF MEASUREMENTS

I. Criteria for cathodic protection—A. Steel, cast iron, and ductile iron structures. (1) A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.

(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. Aluminum structures. (1) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II and IV of this appendix.

(2) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(3) Notwithstanding the alternative minimum criteria in paragraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half cell, in accordance with section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.
their voltage equivalent to \(-0.85\) volt as referred to a saturated copper-copper sulfate half cell:

1. Saturated KCl calomel half cell: \(-0.78\) volt.
2. Silver-silver chloride half cell used in sea water: \(-0.80\) volt.

C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

[Amdt. 192–4, 36 FR 12305, June 30, 1971]
Subpart H—Personnel Qualifications and Training

193.2701 Scope.
193.2703 Design and fabrication.
193.2705 Construction, installation, inspection, and testing.
193.2707 Operations and maintenance.
193.2709 Security.
193.2711 Personnel health.
193.2713 Training: operations and maintenance.
193.2715 Training: security.
193.2717 Training: fire protection.
193.2719 Training: records.

Subpart I—Fire Protection

193.2801 Scope.

Subpart J—Security

193.2901 Scope.
193.2903 Security procedures.
193.2905 Protective enclosures.
193.2907 Protective enclosure construction.
193.2909 Security communications.
193.2911 Security lighting.
193.2913 Security monitoring.
193.2915 Alternative power sources.
193.2917 Warning signs.

APPENDIX A TO PART 193—INCORPORATION BY REFERENCE

AUTHORITY: 49 U.S.C. 5103, 60102, 60103, 60104, 60108, 60109, 60110, 60113, 60118; and 49 CFR 1.53.

SOURCE: 45 FR 9203, Feb. 11, 1980, unless otherwise noted.

Subpart A—General

§ 193.2001 Scope of part.

(a) This part prescribes safety standards for LNG facilities used in the transportation of gas by pipeline that is subject to the pipeline safety laws (49 U.S.C. 60101 et seq.) and Part 192 of this chapter.

(b) This part does not apply to:

(1) LNG facilities used by ultimate consumers of LNG or natural gas.

(2) LNG facilities used in the course of natural gas treatment or hydrocarbon extraction which do not store LNG.

(3) In the case of a marine cargo transfer system and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before a storage tank.

(4) Any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act (16 U.S.C. 796(8))).


§ 193.2003 [Reserved]

§ 193.2005 Applicability.

(a) Safety requirements mandating compliance with standard ANSI/NFPA 59A and other changes in this part governing siting, design, construction, equipment, fire protection, operation and maintenance apply to LNG facilities placed in service after March 31, 2000 unless otherwise noted.

(b) If an existing LNG facility (or facility under construction before March 31, 2000 is replaced, relocated or significantly altered after March 31, 2000, the facility must comply with the applicable requirements of this part governing siting, design, installation, and construction, except that:

(1) The siting requirements apply only to LNG storage tanks that are significantly altered by increasing the original storage capacity or relocated, and

(2) To the extent compliance with the design, installation, and construction requirements would make the replaced, relocated, or altered facility incompatible with the other facilities or would otherwise be impractical, the replaced, relocated, or significantly altered facility may be designed, installed, or constructed in accordance with the original specifications for the facility, or in another manner subject to the approval of the Administrator.


§ 193.2007 Definitions.

As used in this part:

Administrator means the Administrator of the Research and Special Programs Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation.

Ambient vaporizer means a vaporizer which derives heat from naturally occurring heat sources, such as the atmosphere, sea water, surface waters, or geothermal waters.
§ 193.2007  Cargo transfer system means a component, or system of components functioning as a unit, used exclusively for transferring hazardous fluids in bulk between a tank car, tank truck, or marine vessel and a storage tank.

Component means any part, or system of parts functioning as a unit, including, but not limited to, piping, processing equipment, containers, control devices, impounding systems, lighting, security devices, fire control equipment, and communication equipment, whose integrity or reliability is necessary to maintain safety in controlling, processing, or containing a hazardous fluid.

Container means a component other than piping that contains a hazardous fluid.

Control system means a component, or system of components functioning as a unit, including control valves and sensing, warning, relief, shutdown, and other control devices, which is activated either manually or automatically to establish or maintain the performance of another component.

Controllable emergency means an emergency where reasonable and prudent action can prevent harm to people or property.

Design pressure means the pressure used in the design of components for the purpose of determining the minimum permissible thickness or physical characteristics of its various parts. When applicable, static head shall be included in the design pressure to determine the thickness of any specific part.

Determine means make an appropriate investigation using scientific methods, reach a decision based on sound engineering judgment, and be able to demonstrate the basis of the decision.

Dike means the perimeter of an impounding space forming a barrier to prevent liquid from flowing in an unintended direction.

Emergency means a deviation from normal operation, a structural failure, or severe environmental conditions that probably would cause harm to people or property.

Exclusion zone means an area surrounding an LNG facility in which an operator or government agency legally controls all activities in accordance with §193.2057 and §193.2059 for as long as the facility is in operation.

Fail-safe means a design feature which will maintain or result in a safe condition in the event of malfunction or failure of a power supply, component, or control device.

g means the standard acceleration of gravity of 9.806 meters per second² (32.17 feet per second²).

Gas, except when designated as inert, means natural gas, other flammable gas, or gas which is toxic or corrosive. Hazardous fluid means gas or hazardous liquid.

Hazardous liquid means LNG or a liquid that is flammable or toxic.

Heated vaporizer means a vaporizer which derives heat from other than naturally occurring heat sources.

Impounding space means a volume of space formed by dikes and floors which is designed to confine a spill of hazardous liquid.

Impounding system includes an impounding space, including dikes and floors for conducting the flow of spilled hazardous liquids to an impounding space.

Liquefied natural gas or LNG means natural gas or synthetic gas having methane (CH₄) as its major constituent which has been changed to a liquid.

LNG facility means a pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas.

LNG plant means an LNG facility or system of LNG facilities functioning as a unit.

m³ means a volumetric unit which is one cubic metre, 6.2898 barrels, 35.3147 ft.³, or 264.1720 U.S. gallons, each volume being considered as equal to the other.

Maximum allowable working pressure means the maximum gage pressure permissible at the top of the equipment, containers or pressure vessels while operating at design temperature.

Normal operation means functioning within ranges of pressure, temperature, flow, or other operating criteria required by this part.

Operator means a person who owns or operates an LNG facility.

Person means any individual, firm, joint venture, partnership, corporation,

(a) As used in this part:

(1) Includes means including but not limited to;

(2) May means is permitted to or is authorized to;

(3) May not means is not permitted to or is not authorized to; and

(4) Shall or must is used in the mandatory and imperative sense.

(b) In this part:

(1) Words importing the singular include the plural; and

(2) Words importing the plural include the singular.

§ 193.2011 Reporting.

Leaks and spills of LNG must be reported in accordance with the requirements of part 191 of this chapter.

§ 193.2013 Incorporation by reference.

(a) There are incorporated by reference in this part all materials referred to in this part that are not set forth in full. The incorporated materials are deemed published under 5 U.S.C. 552(a) and 1 CFR part 51 and are part of this regulation as though set forth in full. All incorporated materials are listed in appendix A to this part 193 with the applicable editions in parentheses following the title of the referenced material. Only the latest listed edition applies, except that an earlier listed edition may be followed with respect to components which are designed, manufactured, or installed in accordance with the earlier edition before the latest edition is adopted, unless otherwise provided in this part. The incorporated materials are subject to change, but any change will be announced by publication in the Federal Register before it becomes effective.

(b) All incorporated materials are available for inspection in the Research and Special Programs Administration, 400 Seventh Street, SW., Washington, DC, and at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC. 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, the incorporated materials are available from the respective organizations listed in appendix A to this part.

(c) Incorporated by reference provisions approved by the Director of the Federal Register.

§ 193.2015 [Reserved]

§ 193.2017 Plans and procedures.

(a) Each operator shall maintain at each LNG plant the plans and procedures required for that plant by this part. The plans and procedures must be available upon request for review and inspection by the Administrator or any State Agency that has submitted a current certification or agreement with respect to the plant under the pipeline safety laws (49 U.S.C. 60101 et seq.). In addition, each change to the plans or procedures must be available at the LNG plant for review and inspection within 20 days after the change is made.

(b) The Administrator or the State Agency that has submitted a current certification under section 5(a) of the Natural Gas Pipeline Safety Act 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.


§ 193.2019 Mobile and temporary LNG facilities.

(a) Mobile and temporary LNG facilities for peakshaving application, for service maintenance during gas pipeline systems repair/alteration, or for other short term applications need not meet the requirements of this part if the facilities are in compliance with applicable sections of NFPA 59A (1996 edition).

(b) The State agency having jurisdiction over pipeline safety in the State in which the portable LNG equipment is to be located must be provided with a location description for the installation at least 2 weeks in advance, including to the extent practical, the details of siting, leakage containment or control, fire fighting equipment, and methods employed to restrict public access, except that in the case of emergency where such notice is not possible, as much advance notice as possible must be provided.


Subpart B—Siting Requirements

§ 193.2051 Scope.

Each LNG facility designed, constructed, replaced, relocated or significantly altered after March 31, 2000 must be provided with siting requirements in accordance with the requirements of this part and of ANSI/NFPA 59A. In the event of a conflict between this part and ANSI/NFPA 59A, this part prevails.


§ 193.2055 [Reserved]

§ 193.2057 Thermal radiation protection.

Each LNG container and LNG transfer system must have a thermal exclusion zone in accordance with section 2–2.3.1 of ANSI/NFPA 59A with the following exceptions:

(a) The thermal radiation distances shall be calculated using Gas Research Institute’s (GRI) report GRI–89/0176, which is also available as the “LNGFIRE III” computer model produced by GRI. The use of other alternative models which take into account the same physical factors and have been validated by experimental test data shall be permitted subject to the Administrator’s approval.

(b) In calculating exclusion distances, the wind speed producing the maximum exclusion distances shall be used except for wind speeds that occur less than 5 percent of the time based on recorded data for the area.

(c) In calculating exclusion distances, the ambient temperature and relative humidity that produce the maximum exclusion distances shall be used except for values that occur less than five percent of the time based on recorded data for the area.


§ 193.2059 Flammable vapor-gas dispersion protection.

Each LNG container and LNG transfer system must have a dispersion exclusion zone in accordance with section
§ 193.2101 Scope.

Each LNG facility designed after March 31, 2000 must comply with the requirements of this part and of ANSI/NFPA 59A. In the event of a conflict
§§ 193.2103–193.2117  
between this part and ANSI/NFPA 59A, this part prevails.  

MATERIALS  

§§ 193.2103–193.2117 [Reserved]  

§ 193.2119 Records  
Each operator shall keep a record of all materials for components, buildings, foundations, and support systems, as necessary to verify that material properties meet the requirements of this part. These records must be maintained for the life of the item concerned.  

DESIGN OF COMPONENTS AND BUILDINGS  

§§ 193.2121–193.2153 [Reserved]  

IMPOUNDMENT DESIGN AND CAPACITY  

§ 193.2155 Structural requirements.  
(a) The structural members of an impoundment system must be designed and constructed to prevent impairment of the system’s performance reliability and structural integrity as a result of the following:  
(i) The imposed loading from—  
(ii) Full hydrostatic head of impounded LNG;  
(iii) Hydrodynamic action, including the effect of any material injected into the system for spill control;  
(iv) The impingement of the trajectory of an LNG jet discharged at any predictable angle; and  
(v) Anticipated hydraulic forces from a credible opening in the component or item served, assuming that the discharge pressure equals design pressure.  
(2) The erosive action from a spill, including jetting of spilling LNG, and any other anticipated erosive action including surface water runoff, ice formation, dislodgement of ice formation, and snow removal.  
(3) The effect of the temperature, any thermal gradient, and any other anticipated degradation resulting from sudden or localized contact with LNG.  
(4) Exposure to fire from impounded LNG or from sources other than impounded LNG.  
(5) If applicable, the potential impact and loading on the dike due to—  
(i) Collapse of the component or item served or adjacent components; and  
(ii) If the LNG facility adjoins the right-of-way of any highway or railroad, collision by or explosion of a train, tank car, or tank truck that could reasonably be expected to cause the most severe loading.  
(b) An LNG storage tank must not be located within a horizontal distance of one mile (1.6 km) from the ends, or ¼ mile (0.4 km) from the nearest point of a runway, whichever is longer. The height of LNG structures in the vicinity of an airport must also comply with Federal Aviation Administration requirements in 14 CFR Section 1.1.  

§§ 193.2157–193.2159 [Reserved]  

§ 193.2161 Dikes, general.  
An outer wall of a component served by an impounding system may not be used as a dike unless the outer wall is constructed of concrete.  

§§ 193.2163–193.2165 [Reserved]  

§ 193.2167 Covered systems.  
A covered impounding system is prohibited except for concrete wall designed tanks where the concrete wall is an outer wall serving as a dike.  

§§ 193.2169–193.2171 [Reserved]  

§ 193.2173 Water removal.  
(a) Impoundment areas must be constructed such that all areas drain completely to prevent water collection. Drainage pumps and piping must be provided to remove water from collecting in the impoundment area. Alternative means of draining may be acceptable subject to the Administrator’s approval.  
(b) The water removal system must have adequate capacity to remove water at a rate equal to 25% of the maximum predictable collection rate from a storm of 10-year frequency and 1-hour duration, and other natural causes. For rainfall amounts, operators must use the “Rainfall Frequency
§§ 193.2175–193.2179 [Reserved]

§ 193.2181 Impoundment capacity: LNG storage tanks.

Each impounding system serving an LNG storage tank must have a minimum volumetric liquid impoundment capacity of:

(a) 110 percent of the LNG tank’s maximum liquid capacity for an impoundment serving a single tank;

(b) 100 percent of all tanks or 110 percent of the largest tank’s maximum liquid capacity, whichever is greater, for the impoundment serving more than one tank; or

(c) If the dike is designed to account for a surge in the event of catastrophic failure, then the impoundment capacity may be reduced to 100 percent in lieu of 110 percent.


§§ 193.2183–193.2185 [Reserved]

§ 193.2187 Nonmetallic membrane liner.

A flammable nonmetallic membrane liner may not be used as an inner container in a storage tank.


§§ 193.2189–193.2233 [Reserved]

Subpart D—Construction

§ 193.2301 Scope.

Each LNG facility constructed after March 31, 2000 must comply with requirements of this part and of ANSI/NFPA 59A. In the event of a conflict between this part and ANSI/NFPA 59A, this part prevails.


§ 193.2303 Construction acceptance.

No person may place in service any component until it passes all applicable inspections and tests prescribed by this subpart and ANSI/NFPA 59A.


§ 193.2304 Corrosion control overview.

(a) Subject to paragraph (b) of this section, components may not be constructed, repaired, replaced, or significantly altered until a person qualified under §193.2707(c) reviews the applicable design drawings and materials specifications from a corrosion control viewpoint and determines that the materials involved will not impair the safety or reliability of the component or any associated components.

(b) The repair, replacement, or significant alteration of components must be reviewed only if the action to be taken—

(1) Involves a change in the original materials specified;

(2) Is due to a failure caused by corrosion; or

(3) Is occasioned by inspection revealing a significant deterioration of the component due to corrosion.


§§ 193.2305–193.2319 [Reserved]

§ 193.2321 Nondestructive tests.

The butt welds in metal shells of storage tanks with internal design pressure above 15 psig must be radiographically tested in accordance with the ASME Boiler and Pressure Vessel Code (Section VIII Division 1), except that hydraulic load bearing shells with curved surfaces that are subject to cryogenic temperatures, 100 percent of both longitudinal (or meridional) and circumferential (or latitudinal) welds must be radiographically tested.

§§ 193.2323–193.2329 [Reserved]

Subpart E—Equipment

§ 193.2401 Scope.

After March 31, 2000, each new, replaced, relocated or significantly altered vaporization equipment, liquefaction equipment, and control systems must be designed, fabricated, and installed in accordance with requirements of this part and of ANSI/NFPA 59A. In the event of a conflict between this part and ANSI/NFPA 59A, this part prevails.


Vaporization Equipment

§§ 193.2403–193.2439 [Reserved]

§ 193.2441 Control center.

Each LNG plant must have a control center from which operations and warning devices are monitored as required by this part. A control center must have the following capabilities and characteristics:

(a) It must be located apart or protected from other LNG facilities so that it is operational during a controllable emergency.

(b) Each remotely actuated control system and each automatic shutdown control system required by this part must be operable from the control center.

(c) Each control center must have personnel in continuous attendance while any of the components under its control are in operation, unless the control is being performed from another control center which has personnel in continuous attendance.

(d) If more than one control center is located at an LNG Plant, each control center must have more than one means of communication with each other center.

(e) Each control center must have a means of communicating a warning of hazardous conditions to other locations within the plant frequented by personnel.

§ 193.2443 [Reserved]

§ 193.2445 Sources of power.

(a) Electrical control systems, means of communication, emergency lighting, and firefighting systems must have at least two sources of power which function so that failure of one source does not affect the capability of the other source.

(b) Where auxiliary generators are used as a second source of electrical power:

(1) They must be located apart or protected from components so that they are not unusable during a controllable emergency;

(2) Fuel supply must be protected from hazards.

Subpart F—Operations

SOURCE: Amdt. 193–2, 45 FR 70405, Oct. 23, 1980, unless otherwise noted.

§ 193.2501 Scope.

This subpart prescribes requirements for the operation of LNG facilities.

§ 193.2503 Operating procedures.

Each operator shall follow one or more manuals of written procedures to provide safety in normal operation and in responding to an abnormal operation that would affect safety. The procedures must include provisions for:

(a) Monitoring components or buildings according to the requirements of §193.2507.

(b) Startup and shutdown, including for initial startup, performance testing to demonstrate that components will operate satisfactorily in service.

(c) Recognizing abnormal operating conditions.

(d) Purging and inerting components according to the requirements of §193.2517.

(e) In the case of vaporization, maintaining the vaporization rate, temperature and pressure so that the resultant gas is within limits established for the vaporizer and the downstream piping;

(f) In the case of liquefaction, maintaining temperatures, pressures, pressure differentials and flow rates, as applicable, within their design limits for:
§ 193.2513 Transfer procedures.

(a) Each transfer of LNG or other hazardous fluid must be conducted in accordance with one or more manuals of written procedures. The procedures must provide for the following:

1. Responding to controllable emergencies, including notifying personnel and using equipment appropriate for handling the emergency.

2. Recognizing an uncontrollable emergency and taking action to minimize harm to the public and personnel, including prompt notification of appropriate local officials of the emergency and possible need for evacuation of the public in the vicinity of the LNG plant.

3. Coordinating with appropriate local officials in preparation of an emergency evacuation plan, which sets forth the steps required to protect the public in the event of an emergency, including catastrophic failure of an LNG storage tank.

4. Coordinating with appropriate local officials in evacuations and emergencies requiring mutual assistance and keeping these officials advised of:

   i. The LNG plant fire control equipment, its location, and quantity of units located throughout the plant;
   
   ii. Potential hazards at the plant, including fires;
   
   iii. Communication and emergency control capabilities at the LNG plant; and
   
   iv. The status of each emergency.

§ 193.2511 Personnel safety.

(a) Each operator shall provide any special protective clothing and equipment necessary for the safety of personnel while they are performing emergency response duties.

(b) All personnel who are normally on duty at a fixed location, such as a building or yard, where they could be harmed by thermal radiation from a burning pool of impounded liquid, must be provided a means of protection at that location from the harmful effects of thermal radiation or a means of escape.

(c) Each LNG plant must be equipped with suitable first-aid material, the location of which is clearly marked and readily available to personnel.
§ 193.2515 Investigations of failures.

(a) Each operator shall investigate the cause of each explosion, fire, or LNG spill or leak which results in:

(1) Death or injury requiring hospitalization; or
(2) Property damage exceeding $10,000.

(b) As a result of the investigation, appropriate action must be taken to minimize recurrence of the incident.

(c) If the Administrator or relevant state agency under the pipeline safety laws (49 U.S.C. 60101 et seq.) investigates an incident, the operator involved shall make available all relevant information and provide reasonable assistance in conducting the investigation. Unless necessary to restore or maintain service, or for safety,
§ 193.2605 Maintenance

（a） Each operator shall determine and perform, consistent with generally accepted engineering practice, the periodic inspections or tests needed to meet the applicable requirements of this subpart and to verify that components meet the maintenance standards prescribed by this subpart.
§ 193.2607 Foreign material.

(a) The presence of foreign material, contaminants, or ice shall be avoided or controlled to maintain the operational safety of each component.

(b) LNG plant grounds must be free from rubbish, debris, and other material which present a fire hazard. Grass areas on the LNG plant grounds must be maintained in a manner that does not present a fire hazard.

§ 193.2609 Support systems.

Each support system or foundation of each component must be inspected for any detrimental change that could impair support.

§ 193.2611 Fire protection.

(a) Maintenance activities on fire control equipment must be scheduled so that a minimum of equipment is taken out of service at any one time and is returned to service in a reasonable period of time.

(b) Access routes for movement of fire control equipment within each LNG plant must be maintained to reasonably provide for use in all weather conditions.

§ 193.2613 Auxiliary power sources.

Each auxiliary power source must be tested monthly to check its operational capability and tested annually for capacity. The capacity test must take into account the power needed to start up and simultaneously operate equipment that would have to be served by that power source in an emergency.

§ 193.2615 Isolating and purging.

(a) Before personnel begin maintenance activities on components handling flammable fluids which are isolated for maintenance, the component must be purged in accordance with a procedure which meets the requirements of AGA “Purging Principles and Practices,” unless the maintenance procedures under §193.2605 provide that the activity can be safely performed without purging.

(b) If the component or maintenance activity provides an ignition source, a technique in addition to isolation valves (such as removing spool pieces or valves and blank flanging the piping, or double block and bleed valving) must be used to ensure that the work area is free of flammable fluids.

§ 193.2617 Repairs.

(a) Repair work on components must be performed and tested in a manner which:

(1) As far as practicable, complies with the applicable requirements of Subpart D of this part; and

(2) Assures the integrity and operational safety of the component being repaired.

(b) For repairs made while a component is operating, each operator shall include in the maintenance procedures under §193.2605 appropriate precautions to maintain the safety of personnel and property during repair activities.

§ 193.2619 Control systems.

(a) Each control system must be properly adjusted to operate within design limits.

(b) If a control system is out of service for 30 days or more, it must be inspected and tested for operational capability before returning it to service.
§ 193.2620 Inspection and testing of control systems.

(c) Control systems in service, but not normally in operation, such as relief valves and automatic shutdown devices, and control systems for internal shutoff valves for bottom penetration tanks must be inspected and tested once each calendar year, not exceeding 15 months, with the following exceptions:

(1) Control systems used seasonally, such as for liquefaction or vaporization, must be inspected and tested before use each season.

(2) Control systems that are intended for fire protection must be inspected and tested at regular intervals not to exceed 6 months.

(d) Control systems that are normally in operation, such as required by a base load system, must be inspected and tested once each calendar year but with intervals not exceeding 15 months.

(e) Relief valves must be inspected and tested for verification of the valve seat lifting pressure and reseating.


§ 193.2621 Testing transfer hoses.

Hoses used in LNG or flammable refrigerant transfer systems must be:

(a) Tested once each calendar year, but with intervals not exceeding 15 months, to the maximum pump pressure or relief valve setting; and

(b) Visually inspected for damage or defects before each use.

§ 193.2623 Inspecting LNG storage tanks.

Each LNG storage tank must be inspected or tested to verify that each of the following conditions does not impair the structural integrity or safety of the tank:

(a) Foundation and tank movement during normal operation and after a major meteorological or geophysical disturbance.

(b) Inner tank leakage.

(c) Effectiveness of insulation.

(d) Frost heave.


§ 193.2625 Corrosion protection.

(a) Each operator shall determine which metallic components could, unless corrosion is controlled, have their integrity or reliability adversely affected by external, internal, or atmospheric corrosion during their intended service life.

(b) Components whose integrity or reliability could be adversely affected by corrosion must be either—

(1) Protected from corrosion in accordance with §§193.2627 through 193.2635, as applicable; or

(2) Inspected and replaced under a program of scheduled maintenance in accordance with procedures established under §193.2605.

§ 193.2627 Atmospheric corrosion control.

Each exposed component that is subject to atmospheric corrosive attack must be protected from atmospheric corrosion by—

(a) Material that has been designed and selected to resist the corrosive atmosphere involved; or

(b) Suitable coating or jacketing.

§ 193.2629 External corrosion control: buried or submerged components.

(a) Each buried or submerged component that is subject to external corrosive attack must be protected from external corrosion by—

(1) Material that has been designed and selected to resist the corrosive environment involved; or

(2) The following means:

(i) An external protective coating designed and installed to prevent corrosion attack and to meet the requirements of §192.461 of this chapter; and

(ii) A cathodic protection system designed to protect components in their entirety in accordance with the requirements of §192.463 of this chapter and placed in operation before October 23, 1981, or within 1 year after the component is constructed or installed, whichever is later.

(b) Where cathodic protection is applied, components that are electrically interconnected must be protected as a unit.

§ 193.2631 Internal corrosion control.

Each component that is subject to internal corrosive attack must be protected from internal corrosion by—

(a) Material that has been designed and selected to resist the corrosive fluid involved; or

(b) Suitable coating, inhibitor, or other means.

§ 193.2633 Interference currents.

(a) Each component that is subject to electrical current interference must be protected by a continuing program to minimize the detrimental effects of currents.

(b) Each cathodic protection system must be designed and installed so as to minimize any adverse effects it might cause to adjacent metal components.

(c) Each impressed current power source must be installed and maintained to prevent adverse interference with communications and control systems.

§ 193.2635 Monitoring corrosion control.

Corrosion protection provided as required by this subpart must be periodically monitored to give early recognition of ineffective corrosion protection, including the following, as applicable:

(a) Each buried or submerged component under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463 of this chapter.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected at least 6 times each calendar year, but with intervals not exceeding 2½ months, to ensure that it is operating properly.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize component protection must be electrically checked for proper performance at least 6 times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each component that is protected from atmospheric corrosion must be inspected at intervals not exceeding 3 years.

(e) If a component is protected from internal corrosion, monitoring devices designed to detect internal corrosion, such as coupons or probes, must be located where corrosion is most likely to occur. However, monitoring is not required for corrosion resistant materials if the operator can demonstrate that the component will not be adversely affected by internal corrosion during its service life. Internal corrosion control monitoring devices must be checked at least two times each calendar year, but with intervals not exceeding 7½ months.

§ 193.2637 Remedial measures.

Prompt corrective or remedial action must be taken whenever an operator learns by inspection or otherwise that atmospheric, external, or internal corrosion is not controlled as required by this subpart.

§ 193.2639 Maintenance records.

(a) Each operator shall keep a record at each LNG plant of the date and type of each maintenance activity performed on each component to meet the requirements of this part. For each LNG facility that is designed and constructed after March 31, 2000 the operator shall also maintain related periodic inspection and testing records that ANSI/NFPA 59A requires. Maintenance records, whether required by this part or ANSI/NFPA 59A, must be kept for a period of not less than five years.

(b) Each operator shall maintain records or maps to show the location of cathodically protected components, neighboring structures bonded to the cathodic protection system, and corrosion protection equipment.

(c) Each of the following records must be retained for as long as the LNG facility remains in service:

(1) Each record or map required by paragraph (b) of this section.

(2) Records of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures.

§ 193.2701 Scope.

This subpart prescribes requirements for personnel qualifications and training.

[45 FR 9219, Feb. 11, 1980]

§ 193.2703 Design and fabrication.

For the design and fabrication of components, each operator shall use—

(a) With respect to design, persons who have demonstrated competence by training or experience in the design of comparable components.

(b) With respect to fabrication, persons who have demonstrated competence by training or experience in the fabrication of comparable components.

[45 FR 9219, Feb. 11, 1980]

§ 193.2705 Construction, installation, inspection, and testing.

(a) Supervisors and other personnel utilized for construction, installation, inspection, or testing must have demonstrated their capability to perform satisfactorily the assigned function by appropriate training in the methods and equipment to be used or related experience and accomplishments.

(b) Each operator must periodically determine whether inspectors performing duties under §193.2307 are satisfactorily performing their assigned function.

[45 FR 9219, Feb. 11, 1980]

§ 193.2707 Operations and maintenance.

(a) Each operator shall utilize for operation or maintenance of components only those personnel who have demonstrated their capability to perform their assigned functions by—

(1) Successful completion of the training required by §§193.2713 and 193.2717; and

(2) Experience related to the assigned operation or maintenance function; and

(3) Acceptable performance on a proficiency test relevant to the assigned function.

(b) A person who does not meet the requirements of paragraph (a) of this section may operate or maintain a component when accompanied and directed by an individual who meets the requirements.

(c) Corrosion control procedures under §193.2605(b), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified by experience and training in corrosion control technology.

§ 193.2709 Security.

Personnel having security duties must be qualified to perform their assigned duties by successful completion of the training required under §193.2715.

§ 193.2711 Personnel health.

Each operator shall follow a written plan to verify that personnel assigned operating, maintenance, security, or fire protection duties at the LNG plant do not have any physical condition that would impair performance of their assigned duties. The plan must be designed to detect both readily observable disorders, such as physical handicaps or injury, and conditions requiring professional examination for discovery.

§ 193.2713 Training: operations and maintenance.

(a) Each operator shall provide and implement a written plan of initial training to instruct—

(i) All permanent maintenance, operating, and supervisory personnel—

(ii) About the characteristics and hazards of LNG and other flammable fluids used or handled at the facility, including, with regard to LNG, low temperatures, flammability of mixtures with air, odorless vapor, boiloff characteristics, and reaction to water and water spray;

(iii) About the potential hazards involved in operating and maintenance activities; and

(iv) To carry out aspects of the operating and maintenance procedures...
§ 193.2715 Training: security.

(a) Personnel responsible for security at an LNG plant must be trained in accordance with a written plan of initial instruction to:
   (1) Recognize breaches of security;
   (2) Carry out the security procedures under §193.2903 that relate to their assigned duties;
   (3) Be familiar with basic plant operations and emergency procedures, as necessary to effectively perform their assigned duties; and
   (4) Recognize conditions where security assistance is needed.
   (b) A written plan of continuing instruction must be conducted at intervals of not more than two years to keep all personnel current on the knowledge and skills they gained in the program of initial instruction.

§ 193.2717 Training: fire protection.

(a) All personnel involved in maintenance and operations of an LNG plant, including their immediate supervisors, must be trained in accordance with a written plan of initial instruction, including plant fire drills, to:
   (1) Know and follow the fire prevention procedures under §193.2805(b);
   (2) Know the potential causes and areas of fire determined under §193.2805(a); (3) Know the types, sizes, and predictable consequences of fire determined under §193.2817(a); and
   (4) Know and be able to perform their assigned fire control duties according to the procedures established under §193.2509 and by proper use of equipment provided under §193.2817.
   (b) A written plan of continuing instruction, including plant fire drills, must be conducted at intervals of not more than two years to keep personnel current on the knowledge and skills they gained in the instruction under paragraph (a) of the section.

§ 193.2719 Training: records.

(a) Each operator shall maintain a system of records which—
   (1) Provide evidence that the training programs required by this subpart have been implemented; and
   (2) Provide evidence that personnel have undergone and satisfactorily completed the required training programs.
   (b) Records must be maintained for one year after personnel are no longer assigned duties at the LNG plant.

Subpart I—Fire Protection

SOURCE: Amdt. 193–2, 45 FR 70408, Oct. 23, 1980, unless otherwise noted.

§ 193.2801 Scope.

Each LNG facility must meet fire prevention and fire control provisions of ANSI/NFPA 59A.


§ § 193.2803–193.2821 [Reserved]

Subpart J—Security

SOURCE: Amdt. 193–2, 45 FR 70409, Oct. 23, 1980, unless otherwise noted.

§ 193.2901 Scope.

This subpart prescribes requirements for security at LNG plants. However, the requirements do not apply to existing LNG plants that do not contain LNG.

(Amdt. 193–4, 52 FR 675, Jan. 8, 1987)
§ 193.2903 Security procedures.

Each operator shall prepare and follow one or more manuals of written procedures to provide security for each LNG plant. The procedures must be available at the plant in accordance with §193.2017 and include at least:

(a) A description and schedule of security inspections and patrols performed in accordance with §193.2913;

(b) A list of security personnel positions or responsibilities utilized at the LNG plant;

(c) A brief description of the duties associated with each security personnel position or responsibility;

(d) Instructions for actions to be taken, including notification of other appropriate plant personnel and law enforcement officials, when there is any indication of an actual or attempted breach of security;

(e) Methods for determining which persons are allowed access to the LNG plant;

(f) Positive identification of all persons entering the plant and on the plant, including methods at least as effective as picture badges; and

(g) Liaison with local law enforcement officials to keep them informed about current security procedures under this section.

§ 193.2905 Protective enclosures.

(a) The following facilities must be surrounded by a protective enclosure:

(1) Storage tanks;

(2) Impounding systems;

(3) Vapor barriers;

(4) Cargo transfer systems;

(5) Process, liquefaction, and vaporization equipment;

(6) Control rooms and stations;

(7) Control systems;

(8) Fire control equipment;

(9) Security communications systems; and

(10) Alternative power sources.

The protective enclosure may be one or more separate enclosures surrounding a single facility or multiple facilities.

(b) Ground elevations outside a protective enclosure must be graded in a manner that does not impair the effectiveness of the enclosure.

(c) Protective enclosures may not be located near features outside of the facility, such as trees, poles, or buildings, which could be used to breach the security.

(d) At least two accesses must be provided in each protective enclosure and be located to minimize the escape distance in the event of emergency.

(e) Each access must be locked unless it is continuously guarded. During normal operations, an access may be unlocked only by persons designated in writing by the operator. During an emergency, a means must be readily available to all facility personnel within the protective enclosure to open each access.

§ 193.2907 Protective enclosure construction.

(a) Each protective enclosure must have sufficient strength and configuration to obstruct unauthorized access to the facilities enclosed.

(b) Openings in or under protective enclosures must be secured by grates, doors or covers of construction and fastening of sufficient strength such that the integrity of the protective enclosure is not reduced by any opening.


§ 193.2909 Security communications.

A means must be provided for:

(a) Prompt communications between personnel having supervisory security duties and law enforcement officials; and

(b) Direct communications between all on-duty personnel having security duties and all control rooms and control stations.

§ 193.2911 Security lighting.

Where security warning systems are not provided for security monitoring under §193.2913, the area around the facilities listed under §193.2905(a) and each protective enclosure must be illuminated with a minimum in service lighting intensity of not less than 2.2 lux (0.2 ft<sup>c</sup>) between sunset and sunrise.

§ 193.2913 Security monitoring.

Each protective enclosure and the area around each facility listed in §193.2905(a) must be monitored for the presence of unauthorized persons. Monitoring must be by visual observation.
§ 193.2915  in accordance with the schedule in the security procedures under §193.2903(a) or by security warning systems that continuously transmit data to an attended location. At an LNG plant with less than 40,000 m$^3$ (250,000 bbl) of storage capacity, only the protective enclosure must be monitored.

§ 193.2915 Alternative power sources.

An alternative source of power that meets the requirements of §193.2445 must be provided for security lighting and security monitoring and warning systems required under §§193.2911 and 193.2913.

§ 193.2917 Warning signs.

(a) Warning signs must be conspicuously placed along each protective enclosure at intervals so that at least one sign is recognizable at night from a distance of 30m (100 ft.) from any way that could reasonably be used to approach the enclosure.

(b) Signs must be marked with at least the following on a background of sharply contrasting color:

The words “NO TRESPASSING,” or words of comparable meaning.


APPENDIX A TO PART 193—INCORPORATION BY REFERENCE

I. List of Organizations and Addresses

A. American Gas Association (AGA), 400 North Capital St., Washington, D.C. 20001.

B. American National Standards Institute (ANSI), 11 West 42nd St., New York, NY 10036.

C. American Society of Civil Engineers (ASCE), Parallel Centre, 1801 Alexander Bell Dr., Reston, VA 20191–4400.

D. American Society of Mechanical Engineers (ASME), Three Park Ave., New York, NY 10016–5990.

E. Gas Research Institute (GRI), 8600 West Bryn Mawr Ave., Chicago, IL 60631.

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

II. Documents Incorporated by Reference, (Numbers in Parentheses Indicate Applicable Editions)

A. American Gas Association (AGA):


B. American Society of Civil Engineers (ASCE):


C. American Society of Mechanical Engineers (ASME):


D. Gas Research Institute (GRI):


E. National Fire Protection Association (NFPA):


PART 194—RESPONSE PLANS FOR ONSHORE OIL PIPELINES

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APPENDIX A TO PART 194—GUIDELINES FOR THE PREPARATION OF RESPONSE PLANS

APPENDIX B TO PART 194—HIGH VOLUME AREAS


SOURCE: 58 FR 253, Jan. 5, 1993, unless otherwise noted.
§ 194.1 Purpose.
This part contains requirements for oil spill response plans to reduce the environmental impact of oil discharged from onshore oil pipelines.

§ 194.3 Applicability.
This part applies to an operator of an onshore oil pipeline that, because of its location, could reasonably be expected to cause substantial harm, or significant and substantial harm to the environment by discharging oil into or on any navigable waters of the United States or adjoining shorelines.

§ 194.5 Definitions.
Adverse weather means the weather conditions considered by the operator in identifying the response systems and equipment to be deployed in accordance with a response plan, including wave height, ice, temperature, visibility, and currents within the inland or Coastal Response Zone (defined in the National Contingency Plan (40 CFR part 300)) in which those systems or equipment are intended to function.

Barrel means 42 United States gallons (159 liters) at 60° Fahrenheit (15.6° Celsius).

Breakout tank means a tank used to:
(1) Relieve surges in an oil pipeline system or
(2) Receive and store oil transported by a pipeline for re-injection and continued transportation by pipeline.

Coastal zone means all United States waters subject to the tide, United States waters of the Great Lakes and Lake Champlain, specified ports and harbors on inland rivers, waters of the contiguous zone, other waters of the high seas subject to the National Contingency Plan, and the land surface or land substrate, ground waters, and ambient air proximal to those waters. (The term “coastal zone” delineates an area of federal responsibility for response action. Precise boundaries are determined by agreements between the Environmental Protection Agency (EPA) and the U.S. Coast Guard (USCG), and are identified in Federal Regional Contingency Plans and Area Contingency Plans.)

Contract or other approved means is:
(1) A written contract or other legally binding agreement between the operator and a response contractor or other spill response organization identifying and ensuring the availability of the specified personnel and equipment within stipulated response times for a specified geographic area; or
(2) Certification that specified equipment is owned or operated by the pipeline operator, and operator personnel and equipment are available within stipulated response times for a specified geographic area; or
(3) Active membership in a local or regional oil spill removal organization that has identified specified personnel and equipment to be available within stipulated response times for a specified geographic area.

Environmentally sensitive area means an area of environmental importance which is in or adjacent to navigable waters.

High volume area means an area which an oil pipeline having a nominal outside diameter of 20 inches (508 millimeters) or more crosses a major river or other navigable waters, which, because of the velocity of the river flow and vessel traffic on the river, would require a more rapid response in case of a worst case discharge or substantial threat of such a discharge. Appendix B to this part contains a list of some of the high volume areas in the United States.

Inland area means the area shoreward of the boundary lines defined in 46 CFR part 7, except that in the Gulf of Mexico, it means the area shoreward of the lines of demarcation (COLREG lines) defined in 33 CFR 80.740–80.850. The inland area does not include the Great Lakes.

Inland zone means the environment inland of the coastal zone excluding the Great Lakes, Lake Champlain, and specified ports and harbors on inland rivers. (The term inland zone delineates an area of federal responsibilities for response actions. Precise boundaries are determined by agreements between the EPA and the USCG and are identified in Federal Regional Contingency Plans.)

Line section means a continuous run of pipe that is contained between adjacent pressure pump stations, between a
pressure pump station and a terminal or breakout tank, between a pressure pump station and a block valve, or between adjacent block valves.


Maximum extent practicable means the limits of available technology and the practical and technical limits on a pipeline operator in planning the response resources required to provide the on-water recovery capability and the shoreline protection and cleanup capability to conduct response activities for a worst case discharge from a pipeline in adverse weather.

Navigable waters means the waters of the United States, including the territorial sea and such waters as lakes, rivers, streams; waters which are used for recreation; and waters from which fish or shellfish are taken and sold in interstate or foreign commerce.

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

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

On-Scene Coordinator (OSC) means the federal official designated by the Administrator of the EPA or by the Commandant of the USCG to coordinate and direct federal response under subpart D of the National Contingency Plan (40 CFR part 300).

Onshore oil pipeline facilities means new and existing pipe, rights-of-way and any equipment, facility, or building used in the transportation of oil located in, on, or under, any land within the United States other than submerged land.

Operator means a person who owns or operates onshore oil pipeline facilities.

Pipeline means all parts of an onshore pipeline facility through which oil moves 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.

Qualified individual means an English-speaking representative of an operator, located in the United States, available on a 24-hour basis, with full authority to: activate and contract with required oil spill removal organization(s); activate personnel and equipment maintained by the operator; act as liaison with the OSC; and obligate any funds required to carry out all required or directed oil response activities.

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

Response area means the inland zone or coastal zone, as defined in the National Contingency Plan (40 CFR part 300), in which the response activity is occurring.

Response plan means the operator’s core plan and the response zone appendices for responding, to the maximum extent practicable, to a worse case discharge of oil, or the substantial threat of such a discharge.

Response resources means the personnel, equipment, supplies, and other resources necessary to conduct response activities.

Response zone means a geographic area either along a length of pipeline or including multiple pipelines, containing one or more adjacent line sections, for which the operator must plan for the deployment of, and provide, spill response capabilities. The size of the zone is determined by the operator after considering available capability, resources, and geographic characteristics.

Specified minimum yield strength means the minimum yield strength, expressed in pounds per square inch, 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.
Worst case discharge means the largest foreseeable discharge of oil, including a discharge from fire or explosion, in adverse weather conditions. This volume will be determined by each pipeline operator for each response zone and is calculated according to §194.105.

§194.103 Worst case discharge

§194.7 Operating restrictions and interim operating authorization.

(a) After February 18, 1993, an operator of a pipeline for which a response plan is required under §194.101, may not handle, store, or transport oil in that pipeline unless the operator has submitted a response plan meeting the requirements of this part.

(b) After August 18, 1993, an operator must operate its onshore pipeline facilities in accordance with the applicable response plan.

(c) After August 18, 1993, the operator of a pipeline line section described in §194.103(c), may continue to operate the pipeline for two years after the date of submission of a response plan, pending approval or disapproval of that plan, only if the operator has submitted the certification required by §194.119(e).

Subpart B—Response Plans

§194.101 Operators required to submit plans.

(a) Except as provided in paragraph (b) of this section, or unless RSPA grants a request from the OSC to require an operator of the following pipelines to submit a response plan or the pipeline is covered by §194.103, each operator of an onshore pipeline facility shall prepare a response plan and submit the response plan to RSPA, as provided in §194.119.

(b) Exception. An operator need not submit a response plan for:

(i) A pipeline that is 6⅜ inches (168 millimeters) or less in outside nominal diameter, is 10 miles (16 kilometers) or less in length, and all of the following conditions apply to the pipeline:

(A) The pipeline has not experienced a release greater than 1,000 barrels (159 cubic meters) within the previous five years,

(ii) The pipeline has not experienced at least two reportable releases, as defined in §195.50, within the previous five years,

(iii) A pipeline containing any electric resistance welded pipe, manufactured prior to 1970, does not operate at a maximum operating pressure established under §195.406 that corresponds to a stress level greater than 50 percent of the specified minimum yield strength of the pipe, and

(iv) The pipeline is not in proximity to navigable waters, public drinking water intakes, or environmentally sensitive areas.

§194.701 Significant and substantial harm; operator’s statement.

(a) Each operator shall submit a statement with its response plan, as required by §§194.107 and 194.113, identifying which line sections in a response zone can be expected to cause significant and substantial harm to the environment in the event of a discharge of oil into or on the navigable waters or adjoining shorelines.

(b) If an operator expects a line section in a response zone to cause significant and substantial harm, then the entire response zone must, for the purpose of response plan review and approval, be treated as if it is expected to
§ 194.105 Worst case discharge.

(a) Each operator shall determine the worst case discharge for each of its response zones and provide the methodology, including calculations, used to arrive at the volume.

(b) The worst case discharge is the largest volume, in barrels (cubic meters), of the following:

1. The pipeline’s maximum release time in hours, plus the maximum shutdown response time in hours (based on historic discharge data or in the absence of such historic data, the operator’s best estimate), multiplied by the maximum flow rate expressed in barrels per hour (based on the maximum daily capacity of the pipeline), plus the largest line drainage volume after shutdown of the line section(s) in the response zone expressed in barrels (cubic meters); or

2. The largest foreseeable discharge for the line section(s) within a response zone, expressed in barrels (cubic meters), based on the maximum historic discharge, if one exists, adjusted for any subsequent corrective or preventive action taken; or

3. If the response zone contains one or more breakout tanks, the capacity of the single largest tank or battery of tanks within a single secondary containment system, adjusted for the capacity or size of the secondary containment system, expressed in barrels (cubic meters).

§ 194.107 General response plan requirements.

(a) Each response plan must plan for resources for responding, to the maximum extent practicable, to a worst case discharge, and to a substantial threat of such a discharge.

(b) Each response plan must be written in English and also, if applicable, in a language that is understood by the personnel responsible for carrying out the plan.

(c) Each response plan must be consistent with the National Contingency Plan (NCP) (40 CFR part 300) and each applicable Area Contingency Plan (ACP). An operator must certify that it has reviewed the NCP and each applicable ACP and that its response plan is consistent with the existing NCP and each existing applicable ACP.

(d) Each response plan must include:

1. A core plan consisting of—
   (i) An information summary as required in §194.113,
   (ii) Immediate notification procedures,
   (iii) Spill detection and mitigation procedures,
   (iv) The name, address, and telephone number of the oil spill response organization, if appropriate,
   (v) Response activities and response resources,
   (vi) Names and telephone numbers of Federal, state and local agencies which the operator expects to have pollution control responsibilities or support,
(vii) Training procedures,
(viii) Equipment testing,
(ix) Drill types, schedules, and procedures, and
(x) Plan review and update procedures; and

(2) An appendix for each response zone. Each response zone appendix must include the information required in paragraph (d)(1) (i)-(ix) of this section that is specific to the response zone and the worst case discharge calculations.

§ 194.109 Submission of state response plans.

(a) In lieu of submitting a response plan required by §194.103, an operator may submit a response plan that complies with a state law or regulation, if the state law or regulation requires a plan that provides equivalent or greater spill protection than a plan required under this part.

(b) A plan submitted under this section must

(1) Have an information summary required by §194.113;
(2) Name the qualified individual; and
(3) Ensure through contract or other approved means the necessary private personnel and equipment to respond to a worst case discharge or a substantial threat of such a discharge.

§ 194.111 Response plan retention.

(a) Each operator shall maintain relevant portions of its response plan at the following locations:

(1) The response plan at the operator's headquarters;
(2) The core plan and relevant response zone appendices for each line section whose pressure may be affected by the operation of a particular pump station, at that pump station; and
(3) The core plan and relevant response zone appendices at any other locations where response activities may be conducted.

(b) Each operator shall provide a copy of its response plan to each qualified individual.

§ 194.113 Information summary.

(a) The information summary for the core plan, required by §194.107, must include:

(1) The name and address of the operator; and
(2) For each response zone which contains one or more line sections that meet the criteria for determining significant and substantial harm as described in §194.103, a listing and description of the response zones, including county(s) and state(s).

(b) The information summary for the response zone appendix, required in §194.107, must include:

(1) The information summary for the core plan;
(2) The name and telephone number of the qualified individual available on a 24-hour basis;
(3) The description of the response zone, including county(s) and state(s), for those zones in which a worst case discharge could cause substantial harm to the environment;
(4) A list of line sections for each pipeline contained in the response zone, identified by milepost or survey station number, or other operator designation;
(5) The basis for the operator’s determination of significant and substantial harm; and
(6) The type of oil and volume of the worst case discharge.

§ 194.115 Response resources.

(a) Each operator shall identify and ensure, by contract or other approved means, the resources necessary to remove, to the maximum extent practicable, a worst case discharge and to mitigate or prevent a substantial threat of a worst case discharge.

(b) An operator shall identify in the response plan the response resources which are available to respond within the time specified, after discovery of a worst case discharge, or to mitigate the substantial threat of such a discharge, as follows:

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<td>High volume area</td>
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<td>All other areas</td>
<td>12 hrs</td>
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§ 194.117 Training.

(a) Each operator shall conduct training to ensure that:

(1) All personnel know—
(1) Their responsibilities under the response plan,
§ 194.119 Submission and approval procedures.

(a) Each operator shall submit two copies of the response plan required by this part. Copies of the response plan shall be submitted to: Pipeline Response Plans Officer, Research and Special Programs Administration, Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590–0001.

(b) If RSPA determines that a response plan requiring approval does not meet all the requirements of this part, RSPA will notify the operator of any alleged deficiencies, and to provide the operator an opportunity to respond, including the opportunity for an informal conference, on any proposed plan revisions and an opportunity to correct any deficiencies.

(c) An operator who disagrees with the RSPA determination that a plan contains alleged deficiencies may petition RSPA for reconsideration within 30 days from the date of receipt of RSPA’s notice. After considering all relevant material presented in writing or at an informal conference, RSPA will notify the operator of its final decision. The operator must comply with the final decision within 30 days of issuance unless RSPA allows additional time.

(d) For those response zones of pipelines, described in §194.103(c), that could reasonably be expected to cause significant and substantial harm, RSPA will approve the response plan if RSPA determines that the response plan meets all requirements of this part, and the OSC raises no objection.

(e) If RSPA has not approved a response plan for a pipeline described in §194.103(c), the operator may submit a certification to RSPA by July 18, 1993, that the operator has obtained, through contract or other approved means, the necessary private personnel and equipment to respond, to the maximum extent practicable, to a worst case discharge or a substantial threat of such a discharge. The certificate must be signed by the qualified individual or an appropriate corporate officer.

(f) If RSPA receives a request from an OSC to review a response plan, RSPA may require an operator to provide a copy of the response plan to the OSC. If an OSC recommends that an operator not previously required to submit a plan to RSPA, should submit one, RSPA will require the operator to
prepare and submit a response plan and send a copy to the OSC.

§ 194.121 Response plan review and update procedures.

(a) Each operator shall review its response plan at least every 5 years from the date of submission and modify the plan to address new or different operating conditions or information included in the plan.

(b) If a new or different operating condition or information would substantially affect the implementation of a response plan, the operator must immediately modify its response plan to address such a change and, within 30 days of making such a change, submit the change to RSPA. Examples of changes in operating conditions that would cause a significant change to an operator’s response plan are:

1. An extension of the existing pipeline or construction of a new pipeline in a response zone not covered by the previously approved plan;
2. Relocation or replacement of the pipeline in a way that substantially affects the information included in the response plan, such as a change to the worst case discharge volume;
3. The type of oil transported, if the type affects the required response resources, such as a change from crude oil to gasoline;
4. The name of the oil spill removal organization;
5. Emergency response procedures;
6. The qualified individual;
7. A change in the NCP or an ACP that has significant impact on the equipment appropriate for response activities; and
8. Any other information relating to circumstances that may affect full implementation of the plan.

(c) If RSPA determines that a change to a response plan does not meet the requirements of this part, RSPA will notify the operator of any alleged deficiencies, and provide the operator an opportunity to respond, including an opportunity for an informal conference, to any proposed plan revisions and an opportunity to correct any deficiencies.

(d) An operator who disagrees with a determination that proposed revisions to a plan are deficient may petition RSPA for reconsideration, within 30 days from the date of receipt of RSPA’s notice. After considering all relevant material presented in writing or at the conference, RSPA will notify the operator of its final decision. The operator must comply with the final decision within 30 days of issuance unless RSPA allows additional time.


APPENDIX A TO PART 194—GUIDELINES FOR THE PREPARATION OF RESPONSE PLANS

This appendix provides recommended form for the preparation and submission of response plans required by 49 CFR part 194. Operators may use other forms provided the form chosen provides the information required by 49 CFR part 194.

Response Plan: Section 1. Information Summary

Section 1 would include the following:

(a) For the core plan:
1. The name and address of the operator; and
2. For each response zone which contains one or more line sections that meet the criteria for determining significant and substantial harm as described in §194.103, a listing and description of the response zones, including county(s) and state(s).

(b) For each response zone appendix:
1. The information summary for the core plan;
2. The name and telephone number of the qualified individual, available on a 24-hour basis;
3. A description of the response zone, including county(s) and state(s) in which a worst case discharge could cause substantial harm to the environment;
4. A list of line sections contained in the response zone, identified by milepost or survey station number or other operator designation.
5. The basis for the operator’s determination of significant and substantial harm; and
6. The type of oil and volume of the worst case discharge.

(d) An operator who disagrees with a determination that proposed revisions to a plan are deficient may petition RSPA for reconsideration, within 30 days from the date of receipt of RSPA’s notice. After considering all relevant material presented in writing or at the conference, RSPA will notify the operator of its final decision. The operator must comply with the final decision within 30 days of issuance unless RSPA allows additional time.

by the plan, including applicable State or local requirements;
(b) A checklist of notifications the operator or qualified individual is required to make under the response plan, listed in the order of priority;
(c) Names of persons (individuals or organizations) to be notified of a discharge, indicating whether notification is to be performed by operating personnel or other personnel;
(d) Procedures for notifying qualified individuals;
(e) The primary and secondary communication methods by which notifications can be made; and
(f) The information to be provided in the initial and each follow-up notification, including the following:
   (1) Name of pipeline;
   (2) Time of discharge;
   (3) Location of discharge;
   (4) Name of oil involved;
   (5) Reason for discharge (e.g., material failure, excavation damage, corrosion);
   (6) Estimated volume of oil discharged;
   (7) Weather conditions on scene; and
   (8) Actions taken or planned by persons on scene.

Response Plan: Section 3. Spill Detection and On-Scene Spill Mitigation Procedures

Section 3 would include the following:
(a) Methods of initial discharge detection;
(b) Procedures, listed in the order of priority, that personnel are required to follow in responding to a pipeline emergency to mitigate or prevent any discharge from the pipeline;
(c) A list of equipment that may be needed in response activities on land and navigable waters, including—
   (1) Transfer hoses and connection equipment;
   (2) Portable pumps and ancillary equipment; and
   (3) Facilities available to transport and receive oil from a leaking pipeline;
(d) Identification of the availability, location, and contact telephone numbers to obtain equipment for response activities on a 24-hour basis; and
(e) Identification of personnel and their location, telephone numbers, and responsibilities for use of equipment in response activities on a 24-hour basis.

Response Plan: Section 4. Response Activities

Section 4 would include the following:
(a) Responsibilities of, and actions to be taken by, operating personnel to initiate and supervise response actions pending the arrival of the qualified individual or other response resources identified in the response plan;
(b) The qualified individual’s responsibilities and authority, including notification of the response resources identified in the plan;
(c) Procedures for coordinating the actions of the operator or qualified individual with the action of the OSC responsible for monitoring or directing those actions;
(d) Oil spill response organizations available, through contract or other approved means, to respond to a worst case discharge to the maximum extent practicable; and
(e) For each organization identified under paragraph (d) of this section, a listing of:
   (1) Equipment and supplies available; and
   (2) Trained personnel necessary to continue operation of the equipment and staff the oil spill removal organization for the first 7 days of the response.

Response Plan: Section 5. List of Contacts

Section 5 would include the names and addresses of the following individuals or organizations, with telephone numbers at which they can be contacted on a 24-hour basis:
(a) A list of persons the plan requires the operator to contact;
(b) Qualified individuals for the operator’s areas of operation;
(c) Applicable insurance representatives or surveyors for the operator’s areas of operation; and
(d) Persons or organizations to notify for activation of response resources.

Response Plan: Section 6. Training Procedures

Section 6 would include a description of the training procedures and programs of the operator.

Response Plan: Section 7. Drill Procedures

Section 7 would include a description of the drill procedures and programs the operator uses to assess whether its response plan will function as planned. It would include:
(a) Announced and unannounced drills;
(b) The types of drills and their frequencies. For example, drills could be described as follows:
   (1) Manned pipeline emergency procedures and qualified individual notification drills conducted quarterly.
   (2) Drills involving emergency actions by assigned operating or maintenance personnel and notification of the qualified individual on pipeline facilities which are normally unmanned, conducted quarterly.
   (3) Shore-based spill management team tabletop drills conducted yearly.
   (4) Oil spill removal organization field equipment deployment drills conducted yearly.
   (5) A drill that exercises the entire response plan for each response zone, would be conducted at least once every 3 years.
Response plan: Section 8. Response Plan Review and Update Procedures

Section 8 would include the following:
(a) Procedures to meet §194.121; and
(b) Procedures to review the plan after a worst case discharge and to evaluate and record the plan's effectiveness.

Response plan: Section 9. Response Zone Appendices.

Each response zone appendix would provide the following information:
(a) The name and telephone number of the qualified individual;
(b) Notification procedures;
(c) Spill detection and mitigation procedures;
(d) Name, address, and telephone number of oil spill response organization;
(e) Response activities and response resources including—
   (1) Equipment and supplies necessary to meet §194.115, and
   (2) The trained personnel necessary to sustain operation of the equipment and to staff the oil spill removal organization and spill management team for the first 7 days of the response;
(f) Names and telephone numbers of Federal, state and local agencies which the operator expects to assume pollution response responsibilities;
(g) The worst case discharge volume;
(h) The method used to determine the worst case discharge volume, with calculations;
   (1) A map that clearly shows—
      (1) The location of the worst case discharge, and
      (2) The distance between each line section in the response zone and—
         (i) Each potentially affected public drinking water intake, lake, river, and stream within a radius of 5 miles (8 kilometers) of the line section, and
         (ii) Each potentially affected environmentally sensitive area within a radius of 1 mile (1.6 kilometers) of the line section;
   (j) A piping diagram and plan-profile drawing of each line section, which may be kept separate from the response plan if the location is identified; and
   (k) For every oil transported by each pipeline in the response zone, emergency response data that—
      (1) Include the name, description, physical and chemical characteristics, health and safety hazards, and initial spill-handling and firefighting methods; and


APPENDIX B TO PART 194—HIGH VOLUME AREAS

As of January 5, 1993 the following areas are high volume areas:

<table>
<thead>
<tr>
<th>Major rivers</th>
<th>Nearest town and state</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arkansas River</td>
<td>N. Little Rock, AR</td>
</tr>
<tr>
<td>Arkansas River</td>
<td>Jenks, OK</td>
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<tr>
<td>Arkansas River</td>
<td>Little Rock, AR</td>
</tr>
<tr>
<td>Black Warrior River</td>
<td>Mount Holly, NC</td>
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<td>Black Warrior River</td>
<td>Glen Rose, TX</td>
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<tr>
<td>Brazos River</td>
<td>Sealy, TX</td>
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<td>Brazos River</td>
<td>Mount Holly, NC</td>
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<tr>
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<td>Sandy Springs, GA</td>
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<tr>
<td>Colorado River</td>
<td>Yuma, AZ</td>
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<tr>
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<tr>
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<td>Lancaster, NH</td>
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<tr>
<td>Coso River</td>
<td>Vincent, AL</td>
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<tr>
<td>Kankakee River</td>
<td>Wilmington, IL</td>
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<td>Cincinnati, OH</td>
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<td>Greensboro, KY</td>
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<td>Wiggins, MS</td>
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<td>Pearl River</td>
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<td>Pearl River</td>
<td>Oka, TX</td>
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<td>Plate River</td>
<td>Opelaha, NE</td>
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<td>Potomac River</td>
<td>Reston, VA</td>
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<tr>
<td>Rappahannock River</td>
<td>Midland, VA</td>
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<tr>
<td>Raritan River</td>
<td>South Bound Brook, NJ</td>
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<td>Raritan River</td>
<td>Highland Park, NJ</td>
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<tr>
<td>Red River (of the South)</td>
<td>Hanna, LA</td>
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<td>Red River (of the North)</td>
<td>Bonham, TX</td>
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<tr>
<td>Red River (of the South)</td>
<td>Dekalb, TX</td>
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<tr>
<td>Red River (of the South)</td>
<td>Sentinell Plantation, LA</td>
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<tr>
<td>Red River (of the North)</td>
<td>Wapeton, ND</td>
</tr>
<tr>
<td>Rio Grande</td>
<td>Anthony, NM</td>
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<tr>
<td>Sabine River</td>
<td>Edgewood, TX</td>
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<td>Orange, TX</td>
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<td>Sabine River</td>
<td>Echo, TX</td>
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<tr>
<td>Savannah River</td>
<td>Hartwell, GA</td>
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</table>
Part 195—Transportation of Hazardous Liquids by Pipeline

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APPENDIX B TO PART 195—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, 60118; and 49 CFR 1.53.

§ 195.2 Definitions.

As used in this part—

Abandoned means permanently removed from service.

Administrator means the Administrator of the Research and Special Programs Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation.

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

Breakout tank means a tank used to relieve surges in a hazardous liquid pipeline system or to 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.

(4) Transportation of petroleum in onshore gathering lines in rural areas except gathering lines in the inlets of the Gulf of Mexico subject to §195.413;

(5) Transportation of hazardous liquid or carbon dioxide in offshore pipelines which are located upstream from the outlet flange of each facility where hydrocarbons or carbon dioxide are produced or where produced hydrocarbons or carbon dioxide are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

(6) Transportation of hazardous liquid or carbon dioxide in Outer Continental Shelf pipelines which are located upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.

(7) 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;

(8) 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 that 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, not including any device and associated piping that are necessary to control pressure in the pipeline under §195.406(b); and

(9) Transportation of carbon dioxide downstream from the following point, as applicable:
   (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 that transports carbon dioxide to injection wells or to headers or manifolds from which pipelines branch to injection wells.

(c) 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).


EDITORIAL NOTE: For Federal Register citations affecting §195.1, see the List of Sections Affected, which appears in the Finding Aids section of the printed volume and on GPO Access.

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Breakout tank means a tank used to relieve surges in a hazardous liquid pipeline system or to 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.
Exposed pipeline means a pipeline where the top of the pipe is protruding above the seabed in water less than 15 feet (4.6 meters) deep, as measured from the 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 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.

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 seabed in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.

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

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 276 kPa (40 psia) at 37.8° C (100° F).

In-plant piping system 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 transportation, 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 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.

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.
§ 195.3

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 CO₂ 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.

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.

§ 195.3 Matter incorporated by reference.

(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 remainder 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 Research and Special Programs Administration, 400 Seventh Street, SW., Washington, DC, and at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC. 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) American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.

(2) American Petroleum Institute (API), 1220 L Street, NW., Washington, DC 20005.
(3) The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, NY 10017.

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

(5) American National Standards Institute (ANSI), 11 West 42nd Street, New York, NY 10036.

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

(7) National Fire Protection Association (NFPA), 11 Tracy Drive, Avon, MA 02322.

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

(1) American Gas Association (AGA): AGA Pipeline Research Committee, Project PR–3–805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe” (December 1989). The RSTRENG program may be used for calculating remaining strength.

(2) American Petroleum Institute (API):

(i) API 510 “Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration” (8th edition, June 1997).


(ix) API Specification 6D “Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves)” (21st edition, 1994).


(xiii) API Standard 650 “Welded Steel Tanks for Oil Storage” (9th edition, July 1993 (Including Addenda 1 through 4).


(3) American Society of Mechanical Engineers (ASME):


§ 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.

[Amdt. 195–45, 56 FR 26925, 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 determined 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 which qualifies for use under this section need not comply with the corrosion control requirements of this part until 12 months
after it is placed in service, notwithstanding any earlier deadlines for compliance. In addition to the requirements of subpart F of this part, the corrosion control requirements of subpart D apply to each pipeline which substantially meets those requirements before it is placed in service or which is a segment that is replaced, relocated, or substantially altered.

(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.


§ 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 Nontransient 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;
§ 195.6

(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.

(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 Ila 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 (NTNCS)* 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.
§ 195.8 Wellhead Protection Area (WHPA)

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.


§ 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.


§ 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 RSPA 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.


§ 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.

Subpart B—Reporting Accidents and Safety-Related Conditions

§ 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) Loss of 50 or more barrels (8 or more cubic meters) of hazardous liquid or carbon dioxide.

(c) Escape to the atmosphere of more than 5 barrels (0.8 cubic meters) a day of highly volatile liquids.
§ 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
§ 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.


§ 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.
§ 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.npmsrspa.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 Information Officer, Research and Special Programs Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366–4566; e-mail, roger.little@rspa.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) Data on pipeline facilities abandoned before October 10, 2000 must be filed by before April 10, 2001. Operators may submit reports by mail, fax or e-mail to the Information Officer, Research and Special Programs Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366–4566;
§ 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.

§ 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 20590.

§ 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 requirements of this part pursuant to the Paperwork Reduction Act of 1980 is 2137–0047.

§ 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.

§ 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.

§ 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.

§ 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.

§ 195.106 Internal design pressure.

(a) Internal design pressure for the pipe in a pipeline is determined in accordance with the following formula:
\[ P = (2 \frac{S}{D}) \times E \times F \]

\( P \) = 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:

(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:

<table>
<thead>
<tr>
<th>Pipe size</th>
<th>No. of tests</th>
</tr>
</thead>
<tbody>
<tr>
<td>Less than 6% in (168 mm) nominal outside diameter.</td>
<td>One test for each 200 lengths.</td>
</tr>
<tr>
<td>6 % in through 12% in (168 mm through 324 mm) nominal outside diameter.</td>
<td>One test for each 100 lengths.</td>
</tr>
<tr>
<td>Larger than 12% in (324 mm) nominal outside diameter.</td>
<td>One test for each 50 lengths.</td>
</tr>
</tbody>
</table>

(ii) If the average yield-tensile ratio exceeds 0.85, the yield strength shall be taken as 30,000 p.s.i. (206,845 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 30,000 p.s.i. (206,845 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:
§ 195.108 External pressure.

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

§ 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, section 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.


§ 195.111 Fracture propagation.

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

[Amend. 195–45, 56 FR 26926, 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 4 1/2 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.


§ 195.114 Used pipe.

Any used pipe installed in a pipeline system must comply with §195.106 (b) or (c) as appropriate.

(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.


§ 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 5 of API Standard 6D.
(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.


§ 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.


§ 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
§ 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.

§ 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.

§ 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.

§ 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.

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

§ 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 m³) 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.

[Amend. 195–66, 64 FR 15933, Apr. 2, 1999]
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.

§ 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.

§ 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.

§ 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 reconstructions must be in accordance with API 510.

§ 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.

§ 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.

§ 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.

§ 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.
§ 195.214 Welding: General.
(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify the 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.


§ 195.216 Welding: Miter joints.
A miter joint is not permitted (not including deflections up to 3 degrees that are caused by misalignment).

§ 195.222 Welders: Qualification of welders.
Each welder must be qualified in accordance with section 3 of API Standard 1104 or section IX of the ASME Boiler and Pressure Vessel Code, except that a welder qualified under an earlier edition than listed in §195.3 may weld but may not requalify under that earlier edition.


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

§ 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.

§ 195.228 Welds and welding inspection: Standards of acceptability.
(a) Each weld and welding must be inspected to insure 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 6 of API Standard 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if the Appendix to API Standard 1104 applies to the weld, the acceptability of the weld may be determined under that appendix.


§ 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 pipelay 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
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§ 195.242 Cathodic protection system.

(a) A cathodic protection system must be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure. A test procedure must be developed to

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.


§ 195.234 Welds: Nondestructive testing.

(a) A weld may be nondestructively tested by any 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.


§ 195.236 External corrosion protection.

Each component in the pipeline system must be provided with protection against external corrosion.

§ 195.238 External coating.

(a) No pipeline system component may be buried or submerged unless that component has an external protective coating that—

(1) Is designed to mitigate corrosion of the buried or submerged component;

(2) Has sufficient adhesion to the metal surface to prevent underfilm migration of moisture;

(3) Is sufficiently ductile to resist cracking;

(4) Has enough strength to resist damage due to handling and soil stress; and

(5) Supports any supplemental cathodic protection.

In addition, if an insulating-type coating is used it must have low moisture absorption and provide high electrical resistance.

(b) All pipe coating must be inspected just prior to lowering the pipe into the ditch or submerging the pipe, and any damage discovered must be repaired.

§ 195.242 Cathodic protection system.

(a) A cathodic protection system must be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure. A test procedure must be developed to
§ 195.244 Test leads.

(a) Except for offshore pipelines, electrical test leads used for corrosion control or electrolysis testing must be installed at intervals frequent enough to obtain electrical measurements indicating the adequacy of the cathodic protection.

(b) Test leads must be installed as follows:

(1) Enough looping or slack must be provided to prevent test leads from being unduly stressed or broken during backfilling.

(2) Each lead must be attached to the pipe so as to prevent stress concentration on the pipe.

(3) Each lead installed in a conduit must be suitably insulated from the conduit.

§ 195.246 Installation of pipe in a ditch.

(a) All pipe installed in a ditch must be installed in a manner that minimizes 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, all offshore pipe in water at least 3.7 m (12 ft) deep but not more than 61 m (200 ft) deep, as measured from the mean low tide, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.


§ 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 sea bottom, as applicable, complies with the following table:

<table>
<thead>
<tr>
<th>Location</th>
<th>Cover inches (millimeters)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>For normal excavation</td>
</tr>
<tr>
<td>Industrial, commercial, and residential areas</td>
<td>36 (914)</td>
</tr>
<tr>
<td>Crossings of inland bodies of water with a width of at least 100 ft (30 mm) from high water mark to high water mark</td>
<td>48 (1219)</td>
</tr>
<tr>
<td>Drainage ditches at public roads and railroads</td>
<td>36 (914)</td>
</tr>
<tr>
<td>Deepwater port safety zone</td>
<td>48 (1219)</td>
</tr>
<tr>
<td>Gulf of Mexico and its inlets and other offshore areas under water less than 12 ft (3.7 m) deep as measured from the mean low tide</td>
<td>36 (914)</td>
</tr>
</tbody>
</table>

§ 195.260 Valves: Location.

An area 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)
§ 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.


§ 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 2–3.4.3; and
   (ii) Impoundment by drainage to a remote impounding area must be installed in accordance with Section 2–3.4.2.

(2) For tanks built to API Standard 2510, the installation of impoundment must be in accordance with Section 3 or 9 of API Standard 2510.

(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 reliefventing 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 must be in accordance with Section 4, and Appendices B and C, of API Specification 12F.

(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.

(3) Pressure-relieving and emergency vacuum-relieving devices installed on low pressure tanks built to API Standard 620 must be in accordance with Section 7 of API Standard 620 and its references to the normal and emergency venting requirements in API Standard 2000.

(4) Pressure and vacuum-relieving devices installed on high pressure tanks
§ 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.


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.


§ 195.302 General requirements.

(a) Except as otherwise provided in this section and in §195.305(b), no operator may operate 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 pipeline’s 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 1976; and
      (B) At least 50 percent of the mileage (length) of all other pipelines; and

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§ 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;

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—

(a) High risk if an area is non-rural or environmentally sensitive; or

(b) Medium risk; or

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

2) The product indicator is:

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

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

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

3) The volume indicator is—

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

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

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

4) The probability of failure indicator is—

(a) 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

(b) 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 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.
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§ 195.306

(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:

§ 195.303—TEST DEADLINES

<table>
<thead>
<tr>
<th>Pipeline Segment</th>
<th>Risk classification</th>
<th>Test deadline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-1970 Pipe susceptible to longitudinal seam failures (defined in § 195.303(c) &amp; (d)).</td>
<td>C or B ...............</td>
<td>12/7/2000 12/7/2002</td>
</tr>
<tr>
<td>All Other Pipeline Segments.</td>
<td>C ...............</td>
<td>12/7/2002</td>
</tr>
<tr>
<td></td>
<td>B ...............</td>
<td>12/7/2004</td>
</tr>
<tr>
<td></td>
<td>A ...............</td>
<td>Additional testing not required</td>
</tr>
</tbody>
</table>

(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.

§ 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.

§ 195.306 Test medium.

(a) Except as provided in paragraphs (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.


§ 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 the test, for at least an additional 4 continuous hours at a pressure equal to 110 percent, or more, of the maximum operating pressure.

§ 195.307 Pressure testing above-ground 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.

(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 5.18 of API Standard 620.

(c) For aboveground breakout tanks built to API Standard 650 and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 5.3 of API Standard 650.

(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.

§ 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.

§ 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; and
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.

Subpart F—Operation and Maintenance

§ 195.400 Scope.

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


§ 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.

(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 §195.406, consider the hazardous liquid or carbon dioxide in transportation,

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(8) In the case of a 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 paragraph 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.

(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
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§ 195.403 Training.

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

(1) Carry out the operating and maintenance, and 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 the 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 liquid or carbon dioxide spills, and to 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;

(5) Learn the proper use of firefighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated pipeline emergency condition; and

(6) In the case of maintenance personnel, to safely repair facilities using appropriate special precautions, such as isolation and purging, when highly volatile liquids are involved.

(b) At 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 training program set forth in paragraph (a) of this section; and

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

(c) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of

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.

(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.

§ 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) Cathodically protected facilities;
   (vi) Facilities to which §195.402(c)(9) applies;
   (vii) Rights-of-way; and
   (viii) 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.


§ 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 15936, Apr. 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 12 3⁄4 inch (324 mm) or less outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa) gage.

(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 §195.305.

(5) For pipelines under §§195.302(b)(1) and (b)(2)(1) 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.


§ 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 appropriate public officials during emergency conditions, including a natural disaster.

§ 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.
§ 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 means 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.


§ 195.413 Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.

(a) Except for gathering lines of 4 1⁄2 inches (114 mm) nominal outside diameter or smaller, each operator shall, in accordance with this section, conduct an underwater inspection of its pipelines in the Gulf of Mexico and its inlets. The inspection must be conducted after October 3, 1989 and before November 16, 1992.

(b) If, as a result of an inspection under paragraph (a) of this section, or upon notification by any person, an operator discovers that a pipeline it operates is exposed on the seabed or constitutes 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 after November 1 of the year that the discovery is made, place the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.


§ 195.414 Cathodic protection.

(a) No operator may operate a hazardous liquid interstate pipeline after March 31, 1973, a hazardous liquid
§ 195.416 External corrosion control.

(a) Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, conduct tests on each buried, in contact with the ground, or submerged pipeline facility in its pipeline system that is under cathodic protection to determine whether the protection is adequate.

(b) Each operator shall maintain the test leads required for cathodic protection in such a condition that electrical measurements can be obtained to ensure adequate protection.

(c) Each operator shall, at intervals not exceeding 2½ months, but at least six times each calendar year, inspect each of its cathodic protection rectifiers.

(d) Each operator shall, at intervals not exceeding 5 years, electrically inspect the bare pipe in its pipeline system that is not cathodically protected and must study leak records for that pipe to determine if additional protection is needed.

(e) Whenever any buried pipe is exposed for any reason, the operator shall examine the pipe for evidence of external corrosion. If the operator finds that there is active corrosion, that the surface of the pipe is generally pitted, or that corrosion has caused a leak, it shall investigate further to determine the extent of the corrosion.

(f) Any pipe that is found to be generally corroded so that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances must be replaced with coated pipe that meets the requirements of this part. However, generally corroded pipe need not be replaced if:

1. The operating pressure is reduced to be commensurate with the limits on operating pressure specified in this subpart, based on the actual remaining wall thickness; or

2. The pipe is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(g) If localized corrosion pitting is found to exist to a degree where leakage might result, the pipe must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe based on the actual remaining wall thickness in the pits.

(h) The strength of the pipe, based on actual remaining wall thickness, for paragraphs (f) and (g) of this section may be determined by the procedure in ASME B31G manual for Determining the Remaining Strength of Corroded
§ 195.418 Internal corrosion control.

(a) No operator may transport any hazardous liquid or carbon dioxide that would corrode the pipe or other components of its pipeline system, unless it has investigated the corrosive effect of the hazardous liquid or carbon dioxide on the system and has taken adequate steps to mitigate corrosion.

(b) If corrosion inhibitors are used to mitigate internal corrosion the operator shall use inhibitors in sufficient quantity to protect the entire part of the system that the inhibitors are designed to protect and shall also use coupons or other monitoring equipment to determine their effectiveness.

(c) The operator shall, at intervals not exceeding 7½ months, but at least twice each calendar year, examine coupons or other types of monitoring equipment to determine the effectiveness of the inhibitors or the extent of any corrosion.

(d) Whenever any pipe is removed from the pipeline for any reason, the operator must inspect the internal surface for evidence of corrosion. If the pipe is generally corroded such that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances, the operator shall investigate adjacent pipe to determine the extent of the corrosion. The corroded pipe must be replaced with pipe that meets the requirements of this part or, based on the actual remaining wall thickness, the operating pressure must be reduced to be commensurate with the limits on operating pressure specified in this subpart.


§ 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.


§ 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.

§ 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;

(2) That line section is isolated to prevent the flow of highly volatile liquid.


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.


§ 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, 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.


§ 195.430 Firefighting equipment.

Each operator shall maintain adequate firefighting equipment at each pump station and breakout tank area. The equipment must be—
§ 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 shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to 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.

§ 195.434 Signs.

Each operator shall maintain signs visible to the public around each pumping station and breakout tank area. Each sign must contain the name of the operator and an emergency telephone number to contact.

§ 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.

§ 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.

§ 195.440 Public education.

Each operator shall establish a continuing educational program to enable the public, appropriate government organizations and persons engaged in excavation-related activities to recognize a hazardous liquid or a carbon dioxide pipeline emergency and to report it to the operator or the fire, police, or other appropriate public officials. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of non-English speaking population in the operator's operating areas.

§ 195.442 Damage prevention program.

(a) Except as provided in paragraph (d) of this section, each operator of a buried pipeline must 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" includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving 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 the 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) or 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 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.

§195.444 CPM leak detection.

Each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid) must comply with API 1130 in operating, maintaining, testing, record keeping, and dispatcher training of the system.

§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;
§ 195.452 Pipeline integrity management in high consequence areas.

(a) Which operators must comply? This section applies to each operator who owns or operates a total of 500 or more miles of hazardous liquid pipeline subject to this part.

(b) What must an operator do? (1) No later than March 31, 2002, an operator must develop a written integrity management program that addresses the risks on each pipeline segment that could affect a high consequence area. An operator must include in the program:

(i) An identification of all pipeline segments that could affect a high consequence area. A pipeline segment in a high consequence area is presumed to affect that area unless the operator’s risk assessment effectively demonstrates otherwise. (See Appendix C of this part for guidance on identifying pipeline segments.) An operator must complete this identification no later than December 31, 2001;

(ii) A plan for baseline assessment of the line pipe (see paragraph (c) of this section);

(iii) A framework addressing each element of the integrity management program, including continual integrity assessment and evaluation (see paragraphs (f) and (j) of this section). The framework must initially indicate how decisions will be made to implement each element.

(2) An operator must implement and follow the program it develops.

(3) In carrying out this section, an operator must follow recognized industry practices unless the section specifies otherwise or 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. For low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure, an operator must select integrity assessment methods capable of assessing seam integrity and of detecting corrosion and deformation anomalies. An operator must assess the integrity of the line pipe by:

(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; or

(C) 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 specified in §195.58 or to the facsimile number specified in §195.56;

(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 the baseline assessment be completed? (1) Time period. An operator must establish a baseline assessment schedule to determine the priority for assessing the pipeline segments. An operator must complete the baseline assessment by March 31, 2008. An operator must assess at least 50% of the line pipe subject to the requirements of this section, beginning with the highest risk pipe, by September 30, 2004.

(2) Prior assessment. To satisfy the requirements of paragraph (c)(1)(i) of this section, an operator may use an integrity assessment conducted after January 1, 1996, if the integrity assessment
method meets the requirements of this section. However, if an operator uses this prior assessment as its baseline assessment, the operator must re-assess the line pipe according to the requirements of paragraph (j)(3) of this section.

(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 characteristics;

(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 repair 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
§ 195.452  

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 be taken to address integrity issues? (1) General requirements. An operator must take prompt action to address all pipeline integrity issues raised by the assessment and information analysis. An operator must evaluate all anomalies and repair those anomalies that could reduce a pipeline's integrity. An operator must comply with §195.422 in making a repair.

(2) Discovery of a condition. Discovery of a condition occurs when an operator has adequate information about the condition to determine the need for repair. Depending on circumstances, an operator may have adequate information when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, excavates the anomaly, or when an operator receives the final internal inspection report. The date of discovery can no later than the date of the integrity assessment results or the final report.

(3) Review of integrity assessment. An operator must include in its schedule for evaluation and repair (as required by paragraph (h)(4) of this section), a schedule for promptly reviewing and analyzing the integrity assessment results. After March 31, 2004, an operator's schedule must provide for review of the integrity assessment results within 120 days of conducting each assessment. The operator must obtain and assess a final report within an additional 90 days.

(4) Schedule for repairs. An operator must complete repairs according to a schedule that prioritizes the conditions for evaluation and repair. An operator must base the schedule on the risk factors listed in paragraph (e)(1) of this section and any pipeline-specific risk factors the operator develops. If an operator cannot meet the schedule for any of the conditions addressed in paragraphs (h)(4)(i) through (iv) of this section, the operator must justify the reasons why the schedule cannot be met and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure until a permanent repair is made. An operator must send a notice to the address specified in §195.58 or to the facsimile number specified in §195.56.

(5) Special requirements for scheduling repairs—(i) Immediate repair conditions. An operator's evaluation and repair schedule must provide for immediate repair conditions. To maintain safety, an operator will need to temporarily reduce operating pressure or shut down the pipeline until the operator can complete the repair of these conditions. An operator must base the temporary operating pressure reduction on remaining wall thickness. An operator must treat the following conditions as immediate repair conditions:

A. Metal loss greater than 80% of nominal wall regardless of dimensions.

B. Predicted burst pressure less than the maximum operating pressure at the location of the anomaly. Burst pressure has been calculated from the remaining strength of the pipe, using a suitable metal loss strength calculation, e.g., ASME/ANSI B31G (“Manual for Determining the Remaining Strength of Corroded Pipelines” (1991)) or AGA Pipeline Research Committee Project PR-9-806 (“A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe” (December.
1989). These documents are available at the addresses listed at §195.3.

(C) Dents on the top of the pipeline (above 4 and 8 o’clock position) with any indicated metal loss.

(D) Significant anomaly that in the judgment of the person evaluating the assessment results requires immediate action.

(ii) 60-day conditions. Except for conditions listed in paragraph (h)(5)(i) of this section, an operator must schedule for evaluation and repair all dents, regardless of size, located on the top of the pipeline (above 4 and 8 o’clock position) within 60 days of discovery of the condition.

(iii) Six-month conditions. Except for conditions listed in paragraph (h)(5)(i) or (ii) of this section, an operator must schedule evaluation and repair of the following within six months of discovery of the condition:

(A) Dents with metal loss or dents that affect pipe curvature at a girth or seam weld.

(B) Dents with reported depths greater than 6% of the pipe diameter.

(C) Remaining strength of the pipe results in a safe operating pressure that is less than the current established MOP at the location of the anomaly using a suitable safe operating pressure calculation method (e.g., 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 available at the addresses listed at §195.3.

(D) Areas of general corrosion with a predicted metal loss of >50% of nominal wall.

(E) Predicted metal loss of >50% of nominal wall at crossings of another pipeline.

(F) Weld anomalies with a predicted metal loss >50% of nominal wall.

(G) Potential crack indications that when excavated are determined to be cracks.

(H) Corrosion of or along seam welds.

(I) Gouges or grooves greater than 12.5% of nominal wall.

(iv) Other conditions. An operator must schedule evaluation and repair of the following conditions:

(A) Data that reflect a change since last assessed.

(B) Data that indicate mechanical damage that is located on the top half of the pipe.

(C) Data that indicate anomalies abrupt in nature.

(D) Data that indicate anomalies longitudinal in orientation.

(E) Data that indicate anomalies over a large area.

(F) Anomalies located in or near casings, crossings of another pipeline, and areas with suspect cathodic protection.

(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;
(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, an operator must install the EFRD. In making this determination, an operator 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) 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 past and present integrity assessment results, information analysis (paragraph (g) of this section), and decisions about repair, and preventive and mitigative actions (paragraphs (h) and (i) of this section).

(3) Assessment intervals. An operator must establish intervals not to exceed five (5) years 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 is obtainable under paragraph (j)(2) of this section. An operator must notify OPS nine months before the end of the intervals of five years or less of the reason why the operator intends to justify a longer interval. An operator must send a notice to the address specified in §195.58 or to the facsimile number specified in §195.56. The notice must state a proposed alternative interval.

(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 intervals of five years or less that the operator may require a longer assessment interval. An operator must send a notice to the address specified in §195.58 or to the facsimile number specified in §195.56. The Operator may have up to an additional 180 days to complete the assessment.

(5) Assessment methods. An operator must assess the integrity of the line pipe by:

(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; or

(iii) 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 60 days before conducting the assessment, by sending a notice to the address specified in §195.58 or to the facsimile number specified in §195.56.

(6) However, for low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure, an operator must select integrity assessment methods capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(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.

(1) What records must be kept? 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.


Subpart G—Qualification of Pipeline Personnel

SOURCE: Amdt. 195–67, 64 FR 46866, Aug. 27, 1999, unless otherwise noted.

§ 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
§ 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; and

(g) Identify those covered tasks and the intervals at which evaluation of the individual’s qualifications is needed.

§ 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.
liquid pipeline facilities and in determining how best to accomplish this, DOT has logi-
cally examined the approach used in the NGPSA. The NGPSA defines the interstate
pipeline facilities subject to exclusive Federal jurisdiction as those subject to the
economic regulatory jurisdiction of the Fed-
eral Energy Regulatory Commission (FERC).
Experience has proven this approach prac-
tical. Unlike the NGPSA however, the
HLPSA has no specific reference to FERC ju-
sisdiction, but instead defines interstate liq-
uid 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 distin-
guishing between interstate and intrastate
pipeline facilities that provide the requisite
degree of certainty to Federal and State en-
forcement personnel and to the regulated en-
tities. 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 facili-
ties.” 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 eco-

omic 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 pipe-
lines, there is only a rebuttable presumption
of jurisdiction created by the filing by pipe-
line operators of tariffs (or concurrences) for
movement of liquids through existing facil-
ities. Although FERC does police the filings
for such matters as compliance with the gen-
eral duties of common carriers, the question
of jurisdiction is normally only aired upon
complaint. While any person, including
State or Federal agencies, can avail them-
selves of the FERC forum by use of the com-
plaint 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 bet-
ter receive and evaluate the type of informa-
tion that is needed to make decisions of this
nature than can DOT.

In delineating which liquid pipeline facili-
ties are interstate pipeline facilities within
the meaning of the HLPSA, DOT will gen-
erally rely on the FERC filings; that is, if
there is a tariff or concurrence filed with
FERC governing the transportation of haz-
ardous liquids over a pipeline facility or if
there has been an exemption from the obli-
gation to file tariffs obtained from FERC, then
DOT will, as a general rule, consider the fa-
cility 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 reg-
ulation. DOT anticipates that the situations
in which there is any question about the va-
lidity of the FERC filings as a ready ref-

erence will be few and that the actual vari-
ations 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 facili-
ties never cross a state line and do not con-
nect 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 transpor-
tation 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 example 1 except that
P does not file any tariffs with FERC.
DOT will assume jurisdiction of the line be-

tween “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 inter-
state 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 op-
erated by another company 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” is located entirely with 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 or 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.

Appendix B to Part 195—Risk-Based Alternative to Pressure Testing Older Hazardous Liquid and Carbon Dioxide Pipelines

This Appendix provides guidance on how a risk-based alternative to pressure testing older hazardous liquid and carbon dioxide pipelines rule allowed by §195.383 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 2-4.

Table 1. Test Requirements—Mainline Segments Outside of Terminals, Stations, and Tank Farms

<table>
<thead>
<tr>
<th>Pipeline segment</th>
<th>Risk classification</th>
<th>Test deadline</th>
<th>Test medium</th>
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APPENDIX B TO PART 195—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 §195.383 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.

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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.

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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 §195.383 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 2-4.

Table 1. Test Requirements—Mainline Segments Outside of Terminals, Stations, and Tank Farms

<table>
<thead>
<tr>
<th>Pipeline segment</th>
<th>Risk classification</th>
<th>Test deadline</th>
<th>Test medium</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-1970 Pipeline Segments susceptible to longitudinal seam failures 2</td>
<td>C or B</td>
<td>12/7/2000</td>
<td>Water only.</td>
</tr>
<tr>
<td>Pre-1970 Pipeline Segments</td>
<td>A</td>
<td>12/7/2002</td>
<td>Water only.</td>
</tr>
<tr>
<td>All Other Pipeline Segments</td>
<td>C</td>
<td>12/7/2002</td>
<td>Water only.</td>
</tr>
<tr>
<td></td>
<td>B</td>
<td>12/7/2004</td>
<td>Water/Liq.</td>
</tr>
</tbody>
</table>


APPENDIX B TO PART 195—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 §195.383 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 2-4.
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**

<table>
<thead>
<tr>
<th>Risk classification</th>
<th>Hazard location indicator</th>
<th>Product/volume indicator</th>
<th>Probability of failure indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>L or M</td>
<td>L/L</td>
<td>L</td>
</tr>
<tr>
<td>B</td>
<td>Not A or C Risk Classification</td>
<td>Any</td>
<td>Any</td>
</tr>
<tr>
<td>C</td>
<td>H</td>
<td>Any</td>
<td>Any</td>
</tr>
</tbody>
</table>

H=High, M=Moderate, L=Low.

**NOTE:** For Location, Product, Volume, and Probability of Failure Indicators, see Tables 3, 4, 5, and 6.

Table 3 is used to establish the LOCATION Indicator used in Table 2. Based on the population and environment characteristics associated with a pipeline facility’s location, a LOCATION Indicator of H, M or L is selected.

**TABLE 3—LOCATION INDICATORS—PIPELINE SEGMENTS**

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Population</th>
<th>Environment</th>
</tr>
</thead>
<tbody>
<tr>
<td>H</td>
<td>Non-rural areas</td>
<td>Environmentally sensitive areas.</td>
</tr>
<tr>
<td>M</td>
<td>Rural areas</td>
<td>Not environmentally sensitive areas.</td>
</tr>
</tbody>
</table>

*The effects of potential vapor migration should be considered for pipeline segments transporting highly volatile or toxic products.

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**

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Considerations</th>
<th>Product examples</th>
</tr>
</thead>
<tbody>
<tr>
<td>H</td>
<td>(Highly volatile and flammable)</td>
<td>(Propane, butane, Natural Gas Liquid (NGL), ammonia)</td>
</tr>
</tbody>
</table>
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 4—PRODUCT INDICATORS—Continued**

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Considerations</th>
<th>Product examples</th>
</tr>
</thead>
<tbody>
<tr>
<td>M</td>
<td>Highly toxic</td>
<td>(Benzene, high Hydrogen Sulfide content crude oils)</td>
</tr>
<tr>
<td>L</td>
<td>Flammable—flashpoint &lt;100°F</td>
<td>(Gasoline, JP4, low flashpoint crude oils)</td>
</tr>
<tr>
<td></td>
<td>Non-flammable—flashpoint 100°F</td>
<td>(Diesel, fuel oil, kerosene, JP5, most crude oils)</td>
</tr>
<tr>
<td></td>
<td>Highly volatile and non-flammable/non-toxic</td>
<td>Carbon Dioxide.</td>
</tr>
</tbody>
</table>

**TABLE 5—VOLUME INDICATORS**

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Line size</th>
</tr>
</thead>
<tbody>
<tr>
<td>H</td>
<td>≥18&quot;</td>
</tr>
<tr>
<td>M</td>
<td>10&quot;–16&quot; nominal diameters.</td>
</tr>
<tr>
<td>L</td>
<td>≤8&quot; nominal diameter.</td>
</tr>
<tr>
<td>H=High</td>
<td>M=Moderate</td>
</tr>
</tbody>
</table>

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**

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Failure history (time-dependent defects)</th>
</tr>
</thead>
<tbody>
<tr>
<td>H¹</td>
<td>≥Three spills in last 10 years.</td>
</tr>
<tr>
<td>L</td>
<td>≤Three spills in last 10 years.</td>
</tr>
<tr>
<td>H=High</td>
<td>L=Low.</td>
</tr>
</tbody>
</table>

¹ Pipeline segments with greater than three product spills in the last 10 years should be reviewed for failure causes as described in subnote². 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.


**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.

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.
3. The Bureau of Transportation Statistics database that includes commercially navigable waterways and non-commercially navigable waterways. The database can be
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. Crossing of roadway with ditches along the side. The ditches could carry a spillage to a waterway.

3. 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.

4. Operating condition of pipeline (pressure, flow rate, etc.) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

5. The hydraulic gradient of pipeline.

6. The diameter of pipeline, the potential release volume, and the distance between the isolation points.

7. Potential physical pathways between the pipeline and the high consequence area.

8. 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(cn)). 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.
III. Safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported.

<table>
<thead>
<tr>
<th>LEAK HISTORY</th>
<th>Safety risk indicator</th>
<th>Leak history (Time-dependent defects) ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>&gt; 3 Spills in last 10 years</td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>&lt; 3 Spills in last 10 years</td>
<td></td>
</tr>
</tbody>
</table>

¹ Time-dependent defects are those that result in spills due to corrosion, gouges, or problems developed during manufacture, construction or operation, etc.

<table>
<thead>
<tr>
<th>LINE SIZE OR VOLUME TRANSPORTED</th>
<th>Safety risk indicator</th>
<th>Line size</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>≥ 18' nominal diameters</td>
<td></td>
</tr>
<tr>
<td>Moderate</td>
<td>10'—16' nominal diameters</td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>≤ 8' nominal diameter</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>AGE OF PIPELINE</th>
<th>Safety risk indicator</th>
<th>Age of Pipeline condition dependent ¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>&gt; 25 years</td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>≤ 25 years</td>
<td></td>
</tr>
</tbody>
</table>

¹ Depends on pipeline’s coating & corrosion condition, and steel quality, toughness, welding.
### PRODUCT TRANSPORTED

<table>
<thead>
<tr>
<th>Safety risk indicator</th>
<th>Considerations ¹</th>
<th>Product examples</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>(Highly volatile and flammable)</td>
<td>(Propane, butane, Natural Gas Liquid (NGL), ammonia).</td>
</tr>
<tr>
<td></td>
<td>Highly toxic</td>
<td>(Benzene, high Hydrogen Sulfide content crude oils).</td>
</tr>
<tr>
<td>Medium</td>
<td>Flammable—flashpoint &lt;100°F</td>
<td>(Gasoline, JP4, low flashpoint crude oils).</td>
</tr>
<tr>
<td>Low</td>
<td>Non-flammable—flashpoint 100°F</td>
<td>(Diesel, fuel oil, kerosene, JP5, most crude oils).</td>
</tr>
</tbody>
</table>

¹The 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 measures 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 189.

(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 repairing anomalies, criteria for repair actions and actions taken to evaluate and repair the anomalies;

(17) other remedial actions planned or taken;

(18) schedule for reviewing and analyzing integrity assessment results;

(19) schedule for evaluation and repair of anomalies, justification to support deviation from required repair times;

(20) risk analysis used to identify additional preventive or mitigative measures, records of preventive and mitigative actions planned or taken;

(21) criteria for determining EFRD installation;

(22) criteria for evaluating and modifying leak detection capability;

(23) methods used to measure the program’s effectiveness.

§ 198.11 Grant authority.

The pipeline safety laws (49 U.S.C. 60101 et seq.) authorize the Administrator to pay out funds appropriated or otherwise made available up to 50 percent of the cost of the personnel, equipment, and activities reasonably required for each state agency to carry out a safety program for intrastate pipeline facilities under a certification or agreement with the Administrator or to act as an agent of the Administrator with respect to interstate pipeline facilities.

(Amdt. 198–2, 61 FR 18518, Apr. 26, 1996)

§ 198.13 Grant allocation formula.

(a) Beginning in calendar year 1993, the Administrator places increasing emphasis on program performance in allocating state agency funds under § 198.11. The maximum percent of each state agency allocation that is based on performance follows: 1993—75 percent; 1994 and subsequent years—100 percent.

(b) A state’s annual grant allocation is based on maximum of 100 performance points derived as follows:

(1) Fifty points based on information provided in the state’s annual certification/agreement attachments which document its activities for the past year; and

(2) Fifty points based on the annual state program evaluation.

(c) The Administrator assigns weights to various performance factors reflecting program compliance, safety priorities, and national concerns identified by the Administrator and communicated to each State agency. At a minimum, the Administrator considers the following performance factors in allocating funds:

(1) Adequacy of state operating practices;

(2) Quality of state inspections, investigations, and enforcement/compliance actions;

(3) Adequacy of state recordkeeping;

(4) Extent of state safety regulatory jurisdiction over pipeline facilities;

(5) Qualifications of state inspectors;

(6) Number of state inspection person-days;

(7) State adoption of applicable federal pipeline safety standards; and

(8) Any other factor the Administrator deems necessary to measure performance.

(d) Notwithstanding these performance factors, the Administrator may, in 1993 and subsequent years, continue funding any state at the 1991 level, provided its request is at the 1991 level or higher and appropriated funds are at the 1991 level or higher.

(e) The Administrator notifies each state agency in writing of the specific performance factors to be used and the
weights to be assigned to each factor at least 9 months prior to allocating funds. Prior to notification, RSPA seeks state agency comments on any proposed changes to the allocation formula.

(f) Grants are limited to the appropriated funds available. If total state agency requests for grants exceed the funds available, the Administrator prorates each state agency’s allocation.

Subpart C—Adoption of One-Call Damage Prevention Program

§ 198.31 Scope.

This subpart implements parts of the pipeline safety laws (49 U.S.C. 60101 et seq.), which direct the Secretary to require each State to adopt a one-call damage prevention program as a condition to receiving a full grant-in-aid for its pipeline safety compliance program.

[Amdt. 198–2, 61 FR 18518, Apr. 26, 1996]

§ 198.33 [Reserved]

§ 198.35 Grants conditioned on adoption of one-call damage prevention program.

In allocating grants to State agencies under the pipeline safety laws, (49 U.S.C. 60101 et seq.), the Secretary considers whether a State has adopted or is seeking to adopt a one-call damage prevention program in accordance with §198.37. If a State has not adopted or is not seeking to adopt such program, the State agency may not receive the full reimbursement to which it would otherwise be entitled.

[Amdt. 198–2, 61 FR 38403, July 24, 1996]

§ 198.37 State one-call damage prevention program.

A State must adopt a one-call damage prevention program that requires each of the following at a minimum:

(a) Each area of the State that contains underground pipeline facilities must be covered by a one-call notification system.

(b) Each one-call notification system must be operated in accordance with §192.614.

(c) Excavators must be required to notify the operational center of the one-call notification system that covers the area of each intended excavation activity and provide the following information:

(1) Name of the person notifying the system.

(2) Name, address and telephone number of the excavator.

(3) Specific location, starting date, and description of the intended excavation activity.

However, an excavator must be allowed to begin an excavation activity in an emergency but, in doing so, required to notify the operational center at the earliest practicable moment.

(d) The State must determine whether telephonic and other communications to the operational center of a one-call notification system under paragraph (c) of this section are to be toll free or not.

(e) Except with respect to interstate transmission facilities as defined in the pipeline safety laws (49 U.S.C. 60101 et seq.), operators of underground pipeline facilities must be required to participate in the one-call notification systems that cover the areas of the State in which those pipeline facilities are located.

(f) Operators of underground pipeline facilities participating in the one-call notification systems that cover the areas of the State in which those pipeline facilities are located.

(g) Persons who operate one-call notification systems or operators of underground pipeline facilities participating or required to participate in the one-call notification systems must be required to notify the public and known excavators in the manner prescribed by §192.614 (b)(4) through (b)(6) of this chapter to notices of intended excavation activity received from the operational center of a one-call notification system.

(h) Operators of underground pipeline facilities (other than operators of...
§ 198.39 Qualifications for operation of one-call notification system.

A one-call notification system qualifies to operate under this subpart if it complies with the following:

(a) It is operated by one or more of the following:

(1) A person who operates underground pipeline facilities or other underground facilities.

(2) A private contractor.

(3) A State or local government agency.

(4) A person who is otherwise eligible under State law to operate a one-call notification system.

(b) It receives and records information from excavators about intended excavation activities.

(c) It promptly transmits to the appropriate operators of underground pipeline facilities the information received from excavators about intended excavation activities.

(d) It maintains a record of each notice of intent to engage in an excavation activity for the minimum time set by the State or, in the absence of such time, for the time specified in the applicable State statute of limitations on tort actions.

(e) It tells persons giving notice of an intent to engage in an excavation activity the names of participating operators of underground pipeline facilities to whom the notice will be transmitted.
Subpart A—General

§ 199.1 Scope.

This part requires operators of pipeline facilities subject to part 192, 193, or 195 of this chapter to test covered employees for the presence of prohibited drugs and alcohol.

[Amdt. 199–19, 66 FR 47117, Sept. 11, 2001]

§ 199.2 Applicability.

(a) This part applies to pipeline operators only with respect to employees located within the territory of the United States, including those employees located within the limits of the “Outer Continental Shelf” as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to any person for whom compliance with this part would violate the domestic laws or policies of another country.

(c) This part does not apply to covered functions performed on—

(1) Master meter systems, as defined in §191.3 of this chapter; or

(2) Pipeline systems that transport only petroleum gas or petroleum gas/air mixtures.

[Amdt. 199–19, 66 FR 47117, Sept. 11, 2001]

§ 199.3 Definitions.

As used in this part—

Accident means an incident reportable under part 191 of this chapter involving gas pipeline facilities or LNG facilities, or an accident reportable under part 195 of this chapter involving hazardous liquid pipeline facilities.

Administrator means the Administrator of the Research and Special Programs Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation.

Covered employee, employee, or individual to be tested means a person who performs a covered function, including persons employed by operators, contractors engaged by operators, and persons employed by such contractors.

Covered function means an operations, maintenance, or emergency-response function regulated by part 192, 193, or 195 of this chapter that is performed on a pipeline or on an LNG facility.

DOT Procedures means the Procedures for Transportation Workplace Drug and Alcohol Testing Programs published by the Office of the Secretary of Transportation in part 40 of this title.

Fail a drug test means that the confirmation test result shows positive evidence of the presence under DOT Procedures of a prohibited drug in an employee’s system.

Operator means a person who owns or operates pipeline facilities subject to part 192, 193, or 195 of this chapter.

Pass a drug test means that initial testing or confirmation testing under DOT Procedures does not show evidence of the presence of a prohibited drug in a person’s system.

Performs a covered function includes actually performing, ready to perform, or immediately available to perform a covered function.

Positive rate means the number of positive results for random drug tests conducted under this subpart plus the number of refusals of random tests required by this subpart, divided by the total number of random drug tests conducted under this subpart plus the number of refusals of random tests required by this subpart.

Prohibited drug means any of the following substances specified in Schedule I or Schedule II of the Controlled Substances Act (21 U.S.C. 812): marijuana, cocaine, opiates, amphetamines, and phencyclidine (PCP).

Refuse to submit, refuse, or refuse to take means behavior consistent with DOT Procedures concerning refusal to take a drug test or refusal to take an alcohol test.

State agency means an agency of any of the several states, the District of Columbia, or Puerto Rico that participates under the pipeline safety laws (49 U.S.C. 60101 et seq.)

[Amdt. 199–19, 66 FR 47117, Sept. 11, 2001]
§ 199.5 DOT procedures.

The anti-drug and alcohol programs required by this part must be conducted according to the requirements of this part and DOT Procedures. Terms and concepts used in this part have the same meaning as in DOT Procedures. Violations of DOT Procedures with respect to anti-drug and alcohol programs required by this part are violations of this part.

[Amdt. 199–19, 66 FR 47118, Sept. 11, 2001]

§ 199.7 Stand-down waivers.

(a) Each operator who seeks a waiver under §40.21 of this title from the stand-down restriction must submit an application for waiver in duplicate to the Associate Administrator for Pipeline Safety, Research and Special Programs Administration, Department of Transportation, Washington, DC 20590.

(b) Each application must—

(1) Identify §40.21 of this title as the rule from which the waiver is sought;

(2) Explain why the waiver is requested and describe the employees to be covered by the waiver;

(3) Contain the information required by §40.21 of this title and any other information or arguments available to support the waiver requested; and

(4) Unless good cause is shown in the application, be submitted at least 60 days before the proposed effective date of the waiver.

(c) No public hearing or other proceeding is held directly on an application before its disposition under this section. If the Associate Administrator determines that the application contains adequate justification, he or she grants the waiver. If the Associate Administrator determines that the application does not justify granting the waiver, he or she denies the application. The Associate Administrator notifies each applicant of the decision to grant or deny an application.

[Amdt. 199–19, 66 FR 47118, Sept. 11, 2001]

§ 199.9 Preemption of State and local laws.

(a) Except as provided in paragraph (b) of this section, this part preempts any State or local law, rule, regulation, or order to the extent that:

(1) Compliance with both the State or local requirement and this part is not possible;

(2) Compliance with the State or local requirement is an obstacle to the accomplishment and execution of any requirement in this part; or

(3) The State or local requirement is a pipeline safety standard applicable to interstate pipeline facilities.

(b) This part shall not be construed to preempt provisions of State criminal law that impose sanctions for reckless conduct leading to actual loss of life, injury, or damage to property, whether the provisions apply specifically to transportation employees or employers or to the general public.


Subpart B—Drug Testing

§ 199.100 Purpose.

The purpose of this subpart is to establish programs designed to help prevent accidents and injuries resulting from the use of prohibited drugs by employees who perform covered functions for operators of certain pipeline facilities subject to part 192, 193, or 195 of this chapter.

[Amdt. 199–19, 66 FR 47118, Sept. 11, 2001]

§ 199.101 Anti-drug plan.

(a) Each operator shall maintain and follow a written anti-drug plan that conforms to the requirements of this part and the DOT Procedures. The plan must contain—

(1) Methods and procedures for compliance with all the requirements of this part, including the employee assistance program;

(2) The name and address of the operator’s Medical Review Officer, and Substance Abuse Professional; and

(4) Procedures for notifying employees of the coverage and provisions of the plan.

(b) The Administrator or the State Agency that has submitted a current certification under the pipeline safety
§ 199.103 Use of persons who fail or refuse a drug test.

(a) An operator may not knowingly use as an employee any person who—
(1) Fails a drug test required by this part and the medical review officer makes a determination under DOT Procedures; or
(2) Refuses to take a drug test required by this part.

(b) Paragraph (a)(1) of this section does not apply to a person who has—
(1) Passed a drug test under DOT Procedures;
(2) Been considered by the medical review officer in accordance with DOT Procedures and been determined by a substance abuse professional to have successfully completed required education or treatment; and
(3) Not failed a drug test required by this part after returning to duty.

§ 199.105 Drug tests required.

Each operator shall conduct the following drug tests for the presence of a prohibited drug:

(a) Pre-employment testing. No operator may hire or contract for the use of any person as an employee unless that person passes a drug test or is covered by an anti-drug program that conforms to the requirements of this part.

(b) Post-accident testing. As soon as possible but no later than 32 hours after an accident, an operator shall drug test each employee whose performance either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. An operator may decide not to test under this paragraph but such a decision must be based on the best information available immediately after the accident that the employee’s performance could not have contributed to the accident or that, because of the time between that performance and the accident, it is not likely that a drug test would reveal whether the performance was affected by drug use.

(c) Random testing. (1) Except as provided in paragraphs (c)(2) through (4) of this section, the minimum annual percentage rate for random drug testing shall be 50 percent of covered employees.

(2) The Administrator’s decision to increase or decrease the minimum annual percentage rate for random drug testing is based on the reported positive rate for the entire industry. All information used for this determination is drawn from the drug MIS reports required by this subpart. In order to ensure reliability of the data, the Administrator considers the quality and completeness of the reported data, may obtain additional information or reports from operators, and may make appropriate modifications in calculating the industry positive rate. Each year, the Administrator will publish in the Federal Register the minimum annual percentage rate for random drug testing of covered employees. The new minimum annual percentage rate for random drug testing will be applicable starting January 1 of the calendar year following publication.

(3) When the minimum annual percentage rate for random drug testing is 50 percent, the Administrator may lower this rate to 25 percent of all covered employees if the Administrator determines that the data received under the reporting requirements of §199.119 for two consecutive calendar years indicate that the reported positive rate is less than 1.0 percent.

(4) When the minimum annual percentage rate for random drug testing is 25 percent, and the data received under the reporting requirements of §199.119 for any calendar year indicate that the reported positive rate is equal to or
§ 199.105

greater than 1.0 percent, the Administrator will increase the minimum annual percentage rate for random drug testing to 50 percent of all covered employees.

(5) The selection of employees for random drug testing shall be made by a scientifically valid method, such as a random number table or a computer-based random number generator that is matched with employees’ Social Security numbers, payroll identification numbers, or other comparable identifying numbers. Under the selection process used, each covered employee shall have an equal chance of being tested each time selections are made.

(6) The operator shall randomly select a sufficient number of covered employees for testing during each calendar year to equal an annual rate not less than the minimum annual percentage rate for random drug testing determined by the Administrator. If the operator conducts random drug testing through a consortium, the number of employees to be tested may be calculated for each individual operator or may be based on the total number of covered employees covered by the consortium who are subject to random drug testing at the same minimum annual percentage rate under this subpart or any DOT drug testing rule.

(7) Each operator shall ensure that random drug tests conducted under this subpart are unannounced and that the dates for administering random tests are spread reasonably throughout the calendar year.

(8) If a given covered employee is subject to random drug testing under the drug testing rules of more than one DOT agency for the same operator, the employee shall be subject to random drug testing at the percentage rate established for the calendar year by the DOT agency regulating more than 50 percent of the employee’s function.

(9) If an operator is required to conduct random drug testing under the drug testing rules of more than one DOT agency, the operator may—

(i) Establish separate pools for random selection, with each pool containing the covered employees who are subject to testing at the same required rate; or

(ii) Randomly select such employees for testing at the highest percentage rate established for the calendar year by any DOT agency to which the operator is subject.

(d) Testing based on reasonable cause.

Each operator shall drug test each employee when there is reasonable cause to believe the employee is using a prohibited drug. The decision to test must be based on a reasonable and articulable belief that the employee is using a prohibited drug on the basis of specific, contemporaneous physical, behavioral, or performance indicators of probable drug use. At least two of the employee’s supervisors, one of whom is trained in detection of the possible symptoms of drug use, shall substantiate and concur in the decision to test an employee. The concurrence between the two supervisors may be by telephone. However, in the case of operators with 50 or fewer employees subject to testing under this part, only one supervisor of the employee trained in detecting possible drug use symptoms shall substantiate the decision to test.

(e) Return-to-duty testing.

A covered employee who refuses to take or has a positive drug test may not return to duty in the covered function until the covered employee has complied with applicable provisions of DOT Procedures concerning substance abuse professionals and the return-to-duty process.

(f) Follow-up testing.

A covered employee who refuses to take or has a positive drug test shall be subject to unannounced follow-up drug tests administered by the operator following the covered employee’s return to duty. The number and frequency of such follow-up testing shall be determined by a substance abuse professional, but shall consist of at least six tests in the first 12 months following the covered employee’s return to duty. In addition, follow-up testing may include testing for alcohol as directed by the substance abuse professional, to be performed in accordance with 49 CFR part 40. Follow-up testing shall not exceed 60 months from the date of the covered employee’s return to duty. The substance abuse professional may terminate the requirement for follow-up testing at any time after the first six
§ 199.111 Tests and additional testing.

(a) Tests have been administered, if the substance abuse professional determines that such testing is no longer necessary.

§ 199.107 Drug testing laboratory.

(a) Each operator shall use for the drug testing required by this part only drug testing laboratories certified by the Department of Health and Human Services under the DOT Procedures.

(b) The drug testing laboratory must permit—

(1) Inspections by the operator before the laboratory is awarded a testing contract; and

(2) Unannounced inspections, including examination of records, at any time, by the operator, the Administrator, and if the operator is subject to state agency jurisdiction, a representative of that state agency.

§ 199.109 Review of drug testing results.

(a) MRO appointment. Each operator shall designate or appoint a medical review officer (MRO). If an operator does not have a qualified individual on staff to serve as MRO, the operator may contract for the provision of MRO services as part of its anti-drug program.

(b) MRO qualifications. Each MRO must be a licensed physician who has the qualifications required by DOT Procedures.

(c) MRO duties. The MRO must perform functions for the operator as required by DOT Procedures.

(d) MRO reports. The MRO must report all drug test results to the operator in accordance with DOT Procedures.

§ 199.111 Retention of samples and additional testing.

(a) Samples that yield positive results on confirmation must be retained by the laboratory in properly secured, long-term, frozen storage for at least 365 days as required by the DOT Procedures. Within this 365-day period, the employee or the employee’s representative, the operator, the Administrator, or, if the operator is subject to the jurisdiction of a state agency, the state agency may request that the laboratory retain the sample for a further reasonable period specified in the request, the sample may be discarded following the end of the 365-day period.
§ 199.113
(b) If the medical review officer (MRO) determines there is no legitimate medical explanation for a confirmed positive test result other than the unauthorized use of a prohibited drug, and if timely additional testing is requested by the employee according to DOT Procedures, the split specimen must be tested. The employee may specify testing by the original laboratory or by a second laboratory that is certified by the Department of Health and Human Services. The operator may require the employee to pay in advance the cost of shipment (if any) and reanalysis of the sample, but the employee must be reimbursed for such expense if the additional test is negative.

c) If the employee specifies testing by a second laboratory, the original laboratory must follow approved chain-of-custody procedures in transferring a portion of the sample.

d) Since some analytes may deteriorate during storage, detected levels of the drug below the detection limits established in the DOT Procedures, but equal to or greater than the established sensitivity of the assay, must, as technically appropriate, be reported and considered corroborative of the original positive results.

§ 199.115 Contractor employees.
With respect to those employees who are contractors or employed by a contractor, an operator may provide by contract that the drug testing, education, and training required by this part be carried out by the contractor provided:

(a) The operator remains responsible for ensuring that the requirements of this part are complied with; and

(b) The contractor allows access to property and records by the operator, the Administrator, and if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purpose of monitoring the operator’s compliance with the requirements of this part.

§ 199.117 Recordkeeping.
(a) Each operator shall keep the following records for the periods specified and permit access to the records as provided by paragraph (b) of this section:

1) Records that demonstrate the collection process conforms to this part must be kept for at least 3 years.

2) Records of employee drug test results that show employees who had a positive test, and the type of test (e.g., post-accident), and records that demonstrate rehabilitation, if any, must be kept for at least 5 years, and include the following information:

   i) The function performed by each employee who had a positive drug test result.

   ii) The prohibited drug(s) that were used by an employee who had a positive drug test.
(iii) The disposition of each employee who had a positive drug test or refused a drug test (e.g., termination, rehabilitation, removed from covered function, other).

(3) Records of employee drug test results that show employees passed a drug test must be kept for at least 1 year.

(4) A record of the number of employees tested, by type of test (e.g., post-accident), must be kept for at least 5 years.

(5) Records confirming that supervisors and employees have been trained as required by this part must be kept for at least 3 years.

(b) Information regarding an individual’s drug testing results or rehabilitation must be released upon the written consent of the individual and as provided by DOT Procedures. Statistical data related to drug testing and rehabilitation that is not name-specific and training records must be made available to the Administrator or the representative of a state agency upon request.

§ 199.119 Reporting of anti-drug testing results.

(a) Each large operator (having more than 50 covered employees) shall submit an annual MIS report to RSPA of its anti-drug testing results in the form and manner prescribed by the Administrator, not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator shall require by written notice that small operators (50 or fewer covered employees) not otherwise required to submit annual MIS reports to prepare and submit such reports to RSPA.

(b) Each report, required under this section, shall be submitted to the Office of Pipeline Safety Compliance (OPS), Research and Special Programs Administration, Department of Transportation, room 2335, 400 Seventh Street, SW., Washington, DC 20590.

(c) Each report shall be submitted in the form and manner prescribed by the Administrator. No other form, including another DOT Operating Administration’s MIS form, is acceptable for submission to RSPA.

(d) Each report shall be signed by the Operator’s anti-drug manager or designated representative. RSPA will allow the operator the option of sending the report on the computer disk provided by RSPA. If this option is used, a signature page attesting to the validity of the information on the computer disk must be sent to the address in paragraph (b) of this section.

(e) Each operator’s report with verified positive test results or refusals to test shall include all of the following informational elements:

1. Number of covered employees.
2. Number of covered employees subject to testing under the anti-drug rules of another operating administration.
3. Number of specimens collected by type of test.
4. Number of positive test results, verified by a Medical Review Officer (MRO), by type of test and type of drug.
5. Number of employee action(s) taken following verified positive(s), by type of action(s).
6. Number of negative tests reported by an MRO by type of test.
7. Number of persons denied a position as a covered employee following a verified positive drug test.
8. Number of covered employees, returned to duty during this reporting period after having failed or refused a drug test required under the RSPA rule.
9. Number of covered employees with tests verified positive by an MRO for multiple drugs.
10. Number of covered employees who refused to submit to a random or non-random (post-accident, reasonable cause, return-to-duty, or follow-up) drug test and the action taken in response to each refusal.
11. Number of supervisors who have received required initial training during the reporting period.

(f) Each operator’s report with only negative test results shall include all of the following informational elements:

1. Number of covered employees.
§ 199.200 Purpose.

The purpose of this subpart is to establish programs designed to help prevent accidents and injuries resulting from the misuse of alcohol by employees who perform covered functions for operators of certain pipeline facilities subject to parts 192, 193, or 195 of this chapter.

§ 199.201 [Reserved]

§ 199.202 Alcohol misuse plan.

Each operator must maintain and follow a written alcohol misuse plan that conforms to the requirements of this part and DOT Procedures concerning alcohol testing programs. The plan shall contain methods and procedures for compliance with all the requirements of this subpart, including required testing, recordkeeping, reporting, education and training elements.

§ 199.209 Other requirements imposed by operators.

(a) Except as expressly provided in this subpart, nothing in this subpart shall be construed to affect the authority of operators, or the rights of employees, with respect to the use or possession of alcohol, including authority and rights with respect to alcohol testing and rehabilitation.

(b) Operators may, but are not required to, conduct pre-employment alcohol testing under this subpart. Each operator that conducts pre-employment alcohol testing must—

(1) Conduct a pre-employment alcohol test before the first performance of covered functions by every covered employee (whether a new employee or someone who has transferred to a position involving the performance of covered functions);

(2) Treat all covered employees the same for the purpose of pre-employment alcohol testing (i.e., you must not test some covered employees and not others);

(3) Conduct the pre-employment tests after making a contingent offer of employment or transfer, subject to the employee passing the pre-employment alcohol test;

(4) Conduct all pre-employment alcohol tests using the alcohol testing procedures in DOT Procedures; and

(5) Not allow any covered employee to begin performing covered functions unless the result of the employee’s test indicates an alcohol concentration of less than 0.04.

§ 199.211 Requirement for notice.

Before performing an alcohol test under this subpart, each operator shall notify a covered employee that the alcohol test is required by this subpart. No operator shall falsely represent that a test is administered under this subpart.

Subpart C—Alcohol Misuse Prevention Program


§ 199.203 [Reserved]

§ 199.205 [Reserved]
§ 199.213 [Reserved]

§ 199.215 Alcohol concentration.

Each operator shall prohibit a covered employee from reporting for duty or remaining on duty requiring the performance of covered functions while having an alcohol concentration of 0.04 or greater. No operator having actual knowledge that a covered employee has an alcohol concentration of 0.04 or greater shall permit the employee to perform or continue to perform covered functions.

§ 199.217 On-duty use.

Each operator shall prohibit a covered employee from using alcohol while performing covered functions. No operator having actual knowledge that a covered employee is using alcohol while performing covered functions shall permit the employee to perform or continue to perform covered functions.

§ 199.219 Pre-duty use.

Each operator shall prohibit a covered employee who has actual knowledge of an accident in which his or her performance of covered functions has not been discounted by the operator as a contributing factor to the accident from using alcohol for eight hours following the accident, unless he or she has been given a post-accident test under §199.225(a), or the operator has determined that the employee’s performance could not have contributed to the accident.

§ 199.221 Use following an accident.

Each operator shall prohibit a covered employee who has actual knowledge of an accident in which his or her performance of covered functions has not been discounted by the operator as a contributing factor to the accident from using alcohol for eight hours following the accident, unless he or she has been given a post-accident test under §199.225(a), or the operator has determined that the employee’s performance could not have contributed to the accident.

§ 199.223 Refusal to submit to a required alcohol test.

Each operator shall require a covered employee to submit to a post-accident alcohol test required under §199.225(a), a reasonable suspicion alcohol test required under §199.225(b), or a follow-up alcohol test required under §199.225(d). No operator shall permit an employee who refuses to submit to such a test to perform or continue to perform covered functions.

§ 199.225 Alcohol tests required.

Each operator shall conduct the following types of alcohol tests for the presence of alcohol:

(a) Post-accident. (1) As soon as practicable following an accident, each operator shall test each surviving covered employee for alcohol if that employee’s performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. The decision not to administer a test under this section shall be based on the operator’s determination, using the best available information at the time of the determination, that the covered employee’s performance could not have contributed to the accident.

(2)(i) If a test required by this section is not administered within 2 hours following the accident, the operator shall prepare and maintain on file a record stating the reasons the test was not promptly administered. If a test required by paragraph (a) is not administered within 8 hours following the accident, the operator shall cease attempts to administer an alcohol test and shall state in the record the reasons for not administering the test.

(ii) [Reserved]

(3) A covered employee who is subject to post-accident testing who fails to remain readily available for such testing, including notifying the operator or operator representative of his/her location if he/she leaves the scene of the accident prior to submission to such test, may be deemed by the operator to have refused to submit to testing. Nothing in this section shall be construed to require the delay of necessary medical attention for injured people following an accident or to prohibit a covered employee from leaving the scene of an accident.
accident for the period necessary to obtain assistance in responding to the accident or to obtain necessary emergency medical care.

(b) Reasonable suspicion testing. (1) Each operator shall require a covered employee to submit to an alcohol test when the operator has reasonable suspicion to believe that the employee has violated the prohibitions in this subpart.

(2) The operator’s determination that reasonable suspicion exists to require the covered employee to undergo an alcohol test shall be based on specific, contemporaneous, articulable observations concerning the appearance, behavior, speech, or body odors of the employee. The required observations shall be made by a supervisor who is trained in detecting the symptoms of alcohol misuse. The supervisor who makes the determination that reasonable suspicion exists shall not conduct the breath alcohol test on that employee.

(3) Alcohol testing is authorized by this section only if the observations required by paragraph (b)(2) of this section are made during, just preceding, or just after the period of the work day that the employee is required to be in compliance with this subpart. A covered employee may be directed by the operator to undergo reasonable suspicion testing for alcohol only while the employee is performing covered functions; just before the employee is to perform covered functions; or just after the employee has ceased performing covered functions.

(4)(i) If a test required by this section is not administered within 2 hours following the determination under paragraph (b)(2) of this section, the operator shall prepare and maintain on file a record stating the reasons the test was not promptly administered. If a test required by this section is not administered within 8 hours following the determination under paragraph (b)(2) of this section, the operator shall cease attempts to administer an alcohol test and shall state in the record the reasons for not administering the test. Records shall be submitted to RSPA upon request of the Administrator.

(ii) [Reserved]

(iii) Notwithstanding the absence of a reasonable suspicion alcohol test under this section, an operator shall not permit a covered employee to report for duty or remain on duty requiring the performance of covered functions while the employee is under the influence of or impaired by alcohol, as shown by the behavioral, speech, or performance indicators of alcohol misuse, nor shall an operator permit the covered employee to perform or continue to perform covered functions, until:

(A) An alcohol test is administered and the employee’s alcohol concentration measures less than 0.02; or

(B) The start of the employee’s next regularly scheduled duty period, but not less than 8 hours following the determination under paragraph (b)(2) of this section that there is reasonable suspicion to believe that the employee has violated the prohibitions in this subpart.

(iv) Except as provided in paragraph (b)(4)(ii), no operator shall take any action under this subpart against a covered employee based solely on the employee’s behavior and appearance in the absence of an alcohol test. This does not prohibit an operator with the authority independent of this subpart from taking any action otherwise consistent with law.

(c) Return-to-duty testing. Each operator shall ensure that before a covered employee returns to duty requiring the performance of a covered function after engaging in conduct prohibited by §§199.215 through 199.223, the employee shall undergo a return-to-duty alcohol test with a result indicating an alcohol concentration of less than 0.02.

(d) Follow-up testing. (1) Following a determination under §199.243(b) that a covered employee is in need of assistance in resolving problems associated with alcohol misuse, each operator shall ensure that the employee is subject to unannounced follow-up alcohol testing as directed by a substance abuse professional in accordance with the provisions of §199.243(c)(2)(ii).

(2) Follow-up testing shall be conducted when the covered employee is
performing covered functions; just before the employee is to perform covered functions; or just after the employee has ceased performing such functions.

(e) Retesting of covered employees with an alcohol concentration of 0.02 or greater but less than 0.04. Each operator shall retest a covered employee to ensure compliance with the provisions of §199.237, if an operator chooses to permit the employee to perform a covered function within 8 hours following the administration of an alcohol test indicating an alcohol concentration of 0.02 or greater but less than 0.04.


§ 199.227 Retention of records.

(a) General requirement. Each operator shall maintain records of its alcohol misuse prevention program as provided in this section. The records shall be maintained in a secure location with controlled access.

(b) Period of retention. Each operator shall maintain the records in accordance with the following schedule:

(1) Five years. Records of employee alcohol test results with results indicating an alcohol concentration of 0.02 or greater, documentation of refusals to take required alcohol tests, calibration documentation, employee evaluation and referrals, and MIS annual report data shall be maintained for a minimum of five years.

(2) Two years. Records related to the collection process (except calibration of evidential breath testing devices), and training shall be maintained for a minimum of two years.

(3) One year. Records of all test results below 0.02 (as defined in 49 CFR part 40) shall be maintained for a minimum of one year.

(c) Types of records. The following specific records shall be maintained:

(1) Records related to the collection process:

(i) Collection log books, if used.

(ii) Calibration documentation for evidential breath testing devices.

(iii) Documentation of breath alcohol technician training.

(iv) Documents generated in connection with decisions to administer reasonable suspicion alcohol tests.

(v) Documents generated in connection with decisions on post-accident tests.

(vi) Documents verifying existence of a medical explanation of the inability of a covered employee to provide adequate breath for testing.

(2) Records related to test results:

(i) The operator’s copy of the alcohol test form, including the results of the test.

(ii) Documents related to the refusal of any covered employee to submit to an alcohol test required by this subpart.

(iii) Documents presented by a covered employee to dispute the result of an alcohol test administered under this subpart.

(3) Records related to other violations of this subpart.

(4) Records related to evaluations:

(i) Records pertaining to a determination by a substance abuse professional concerning a covered employee’s need for assistance.

(ii) Records concerning a covered employee’s compliance with the recommendations of the substance abuse professional.

(5) Record(s) related to the operator’s MIS annual testing data.

(6) Records related to education and training:

(i) Materials on alcohol misuse awareness, including a copy of the operator’s policy on alcohol misuse.

(ii) Documentation of compliance with the requirements of §199.231.

(iii) Documentation of training provided to supervisors for the purpose of qualifying the supervisors to make a determination concerning the need for alcohol testing based on reasonable suspicion.

(iv) Certification that any training conducted under this subpart complies with the requirements for such training.

§ 199.229 Reporting of alcohol testing results.

(a) Each large operator (having more than 50 covered employees) shall submit an annual management information system (MIS) report to RSPA of
its alcohol testing results in the form and manner prescribed by the Administrator, by March 15 of each year for the previous calendar year (January 1 through December 31). The Administrator may require by written notice that a small operator (50 or fewer covered employees), not otherwise required to submit annual MIS reports, submit such a report to RSPA.

(b) Each operator that is subject to more than one DOT agency alcohol rule shall identify each employee covered by the regulations of more than one DOT agency. The identification will be by the total number of covered employees. Prior to conducting any alcohol test on a covered employee subject to the rules of more than one DOT agency, the employer shall determine which DOT agency rule or rules authorizes or requires the test. The test result information shall be directed to the appropriate DOT agency or agencies.

(c) Each report, required under this section, shall be submitted to the Office of Pipeline Safety, Research and Special Programs Administration, Department of Transportation, room 2335, 400 Seventh Street, SW., Washington, DC 20590. RSPA will allow the operator the option of sending the report on the computer disk provided by RSPA. If this option is used, a signature page attesting to the validity of the information on the computer disk must be sent to the address in this section.

(d) Each report that contains information on an alcohol screening test result of 0.02 or greater or a violation of the alcohol misuse provisions of §§199.215 through 199.223 of this subpart shall be submitted on “RSPA Alcohol Testing MIS Data Collection Form” and include the following informational elements:

(1) Number of covered employees.
(2) Number of covered employees subject to testing under the alcohol misuse rule of another operating administration by each agency.
(3)(i) Number of screening tests by type of test.
(ii) Number of confirmation tests by type of test.
(4) Number of confirmation tests indicating an alcohol concentration of 0.02 or greater but less than 0.04, by type of test.
(5) Number of confirmation tests indicating an alcohol concentration of 0.04 or greater, by type of test.
(6) Number of covered employees with a confirmation test indicating an alcohol concentration of 0.04 or greater or who have violations of other alcohol misuse provisions who were returned to duty in covered positions (having complied with the recommendations of a substance abuse professional as described in §§199.235 and 199.243).
(7) Number of covered employees who were administered alcohol and drug tests at the same time, with both a positive drug test and an alcohol test indicating an alcohol concentration of 0.04 or greater.
(8) Number of covered employees who were found to have violated other provisions of §§199.215 through 199.221, and any action taken in response to the violation.
(9) Number of covered employees who refused to submit to an alcohol test required under this subpart, and the action taken in response to the refusal.
(10) Number of supervisors who have received required training during the reporting period in determining the existence of reasonable suspicion of alcohol misuse.

(e) Each report with no screening alcohol test results of 0.02, or greater or violations of the alcohol misuse provisions of §§199.215 through 199.223 of this subpart shall be submitted on “RSPA Alcohol Testing MIS Data Collection EZ Form” and include the following informational elements. (This “EZ” report may only be submitted if the program results meet these criteria)

(1) Number of covered employees.
(2) Number of covered employees subject to testing under the alcohol misuse rule of another operating administration identified by each agency.
(3) Number of screening tests by type of test.
(4) Number of screening tests by type of test.
(5) Number of supervisors who have received required training during the
reporting period in determining the existence of reasonable suspicion of alcohol misuse.

(f) A consortium may prepare reports on behalf of individual pipeline operators for purposes of compliance with this reporting requirement. However, the pipeline operator shall sign and submit such a report and shall remain responsible for ensuring the accuracy and timeliness of each report prepared on its behalf by a consortium.


§ 199.231 Access to facilities and records.

(a) Except as required by law or expressly authorized or required in this subpart, no employer shall release covered employee information that is contained in records required to be maintained in § 199.227.

(b) A covered employee is entitled, upon written request, to obtain copies of any records pertaining to the employee’s use of alcohol, including any records pertaining to his or her alcohol tests. The operator shall promptly provide the records requested by the employee. Access to a employee’s records shall not be contingent upon payment for records other than those specifically requested.

(c) Each operator shall permit access to all facilities utilized in complying with the requirements of this subpart to the Secretary of Transportation, any DOT agency, or a representative of a state agency with regulatory authority over the operator.

(d) Each operator shall make available copies of all results for employer alcohol testing conducted under this subpart and any other information pertaining to the operator’s alcohol misuse prevention program, when requested by the Secretary of Transportation, any DOT agency with regulatory authority over the operator, or a representative of a state agency with regulatory authority over the operator. The information shall include name-specific alcohol test results, records, and reports.

(e) When requested by the National Transportation Safety Board as part of an accident investigation, an operator shall disclose information related to the operator’s administration of any post-accident alcohol tests administered following the accident under investigation.

(f) An operator shall make records available to a subsequent employer upon receipt of the written request from the covered employee. Disclosure by the subsequent employer is permitted only as expressly authorized by the terms of the employee’s written request.

(g) An operator may disclose information without employee consent as provided by DOT Procedures concerning certain legal proceedings.

(h) An operator shall release information regarding a covered employee’s records as directed by the specific, written consent of the employee authorizing release of the information to an identified person. Release of such information by the person receiving the information is permitted only in accordance with the terms of the employee’s consent.


§ 199.233 Removal from covered function.

Except as provided in §§ 199.239 through 199.243, no operator shall permit any covered employee to perform covered functions if the employee has engaged in conduct prohibited by §§ 199.215 through 199.223 or an alcohol misuse rule of another DOT agency.

§ 199.235 Required evaluation and testing.

No operator shall permit a covered employee who has engaged in conduct prohibited by §§ 199.215 through 199.223 to perform covered functions unless the employee has met the requirements of § 199.243.

§ 199.237 Other alcohol-related conduct.

(a) No operator shall permit a covered employee tested under the provisions of § 199.225, who is found to have an alcohol concentration of 0.02 or greater but less than 0.04, to perform or continue to perform covered functions, until:
§ 199.239 Operator obligation to promulgate a policy on the misuse of alcohol.

(a) General requirements. Each operator shall provide educational materials that explain these alcohol misuse requirements and the operator’s policies and procedures with respect to meeting those requirements.

(1) The operator shall ensure that a copy of these materials is distributed to each covered employee prior to start of alcohol testing under this subpart, and to each person subsequently hired for or transferred to a covered position.

(2) Each operator shall provide written notice to representatives of employee organizations of the availability of this information.

(b) Required content. The materials to be made available to covered employees shall include detailed discussion of at least the following:

(1) The identity of the person designated by the operator to answer covered employee questions about the materials.

(2) The categories of employees who are subject to the provisions of this subpart.

(3) Sufficient information about the covered functions performed by those employees to make clear what period of the work day the covered employee is required to be in compliance with this subpart.

(4) Specific information concerning covered employee conduct that is prohibited by this subpart.

(5) The circumstances under which a covered employee will be tested for alcohol under this subpart.

(6) The procedures that will be used to test for the presence of alcohol, protect the covered employee and the integrity of the breath testing process, safeguard the validity of the test results, and ensure that those results are attributed to the correct employee.

(7) The requirement that a covered employee submit to alcohol tests administered in accordance with this subpart.

(8) An explanation of what constitutes a refusal to submit to an alcohol test and the attendant consequences.

(9) The consequences for covered employees found to have violated the prohibitions under this subpart, including the requirement that the employee be removed immediately from covered functions, and the procedures under §199.243.

(10) The consequences for covered employees found to have an alcohol concentration of 0.02 or greater but less than 0.04.

(11) Information concerning the effects of alcohol misuse on an individual’s health, work, and personal life; signs and symptoms of an alcohol problem (the employee’s or a coworker’s); and including intervening evaluating and resolving problems associated with the misuse of alcohol including intervening when an alcohol problem is suspected, confrontation, referral to any available EAP, and/or referral to management.

(c) Optional provisions. The materials supplied to covered employees may also include information on additional operator policies with respect to the use or possession of alcohol, including any consequences for an employee found to have a specified alcohol level, that are based on the operator’s authority independent of this subpart. Any such additional policies or consequences shall be clearly described as being based on independent authority.

§ 199.241 Training for supervisors.

Each operator shall ensure that persons designated to determine whether reasonable suspicion exists to require a covered employee to undergo alcohol
testing under §199.225(b) receive at least 60 minutes of training on the physical, behavioral, speech, and performance indicators of probable alcohol misuse.


(a) Each covered employee who has engaged in conduct prohibited by §§199.215 through 199.223 of this subpart shall be advised of the resources available to the covered employee in evaluating and resolving problems associated with the misuse of alcohol, including the names, addresses, and telephone numbers of substance abuse professionals and counseling and treatment programs.

(b) Each covered employee who engages in conduct prohibited under §§199.215 through 199.223 shall be evaluated by a substance abuse professional who shall determine what assistance, if any, the employee needs in resolving problems associated with alcohol misuse.

(c)(1) Before a covered employee returns to duty requiring the performance of a covered function after engaging in conduct prohibited by §§199.215 through 199.223 of this subpart, the employee shall undergo a return-to-duty alcohol test with a result indicating an alcohol concentration of less than 0.02.

(2) In addition, each covered employee identified as needing assistance in resolving problems associated with alcohol misuse—

(i) Shall be evaluated by a substance abuse professional to determine that the employee has properly followed any rehabilitation program prescribed under paragraph (b) of this section, and

(ii) Shall be subject to unannounced follow-up alcohol tests administered by the operator following the employee’s return to duty. The number and frequency of such follow-up testing shall be determined by a substance abuse professional, but shall consist of at least six tests in the first 12 months following the employee’s return to duty. In addition, follow-up testing may include testing for drugs, as directed by the substance abuse professional, to be performed in accordance with 49 CFR part 40. Follow-up testing shall not exceed 60 months from the date of the employee’s return to duty. The substance abuse professional may terminate the requirement for follow-up testing at any time after the first six tests have been administered, if the substance abuse professional determines that such testing is no longer necessary.

(d) Evaluation and rehabilitation may be provided by the operator, by a substance abuse professional under contract with the operator, or by a substance abuse professional not affiliated with the operator. The choice of substance abuse professional and assignment of costs shall be made in accordance with the operator/employee agreements and operator/employee policies.

(e) The operator shall ensure that a substance abuse professional who determines that a covered employee requires assistance in resolving problems with alcohol misuse does not refer the employee to the substance abuse professional’s private practice or to a person or organization from which the substance abuse professional receives remuneration or in which the substance abuse professional has a financial interest. This paragraph does not prohibit a substance abuse professional from referring an employee for assistance provided through—

(1) A public agency, such as a State, county, or municipality;

(2) The operator or a person under contract to provide treatment for alcohol problems on behalf of the operator;

(3) The sole source of therapeutically appropriate treatment under the employee’s health insurance program; or

(4) The sole source of therapeutically appropriate treatment reasonably accessible to the employee.

§ 199.245 Contractor employees.

(a) With respect to those covered employees who are contractors or employed by a contractor, an operator may provide by contract that the alcohol testing, training and education required by this subpart be carried out by the contractor provided:

(b) The operator remains responsible for ensuring that the requirements of this subpart and part 40 of this title are complied with; and

(c) The contractor allows access to property and records by the operator,
§ 199.245

the Administrator, any DOT agency with regulatory authority over the operator or covered employee, and, if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purposes of monitoring the operator's compliance with the requirements of this subpart and part 40 of this title.
FINDING AIDS

A list of CFR titles, subtitles, chapters, subchapters and parts and an alphabetical list of agencies publishing in the CFR are included in the CFR Index and Finding Aids volume to the Code of Federal Regulations which is published separately and revised annually.

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(Revised as of October 1, 2001)

The Director of the Federal Register has approved under 5 U.S.C. 552(a) and 1 CFR part 51 the incorporation by reference of the following publications. This list contains only those incorporations by reference effective as of the revision date of this volume. Incorporations by reference found within a regulation are effective upon the effective date of that regulation. For more information on incorporation by reference, see the preliminary pages of this volume.

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| P.O. Box 19150, Redford Station, Detroit, MI 48219 | 193.2307; Appendix A to part 193 |

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211 N. Ervay, Suite 1700, Dallas, TX 75201


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API Specification 6D “Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves)” (21st edition, 1994).

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API Standard 650 “Welded Steel Tanks for Oil Storage” (9th edition, July 1993, including Addenda 1 through 4).

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American Society of Civil Engineers (ASCE)
345 East 47th Street, New York, NY 10017–2398

American Society of Mechanical Engineers (ASME)
Three Park Avenue, New York, NY 10016–5990; Telephone: (800) THE–ASME

Boiler and Pressure Vessel Code:
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ASME/ANSI B16.1 Cast Iron Pipe Flanges and Flanged Fittings (1989) 192.147; appendix A to part 192

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American Society for Testing and Materials
100 Barr Harbor Drive, West Conshohocken, PA, 19428-2959, Telephone (610) 832-9585, FAX (610) 832-9555
Noncurrent ASTM standards are available from: Engineering Societies Library, 345 E. 47th St., New York, NY 10017.

ASTM A 53–95a Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated Welded and Seamless. 192.113; appendix A and B to part 192; 195.3; 195.106

ASTM A 106–94a Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service. 192.113; appendix A and B to part 192; 195.3; 195.106


ASTM A 372/A 372M–95 Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels. 192.177; appendix A to part 192

ASTM A 381–93 Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems. 192.113; appendix A and B to part 192; 195.3; 195.106

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ASTM D 2513–95c Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings. 192.63 (except for 192.63(a)(1)); 192.191; 192.281; 192.283; appendix A and B to part 192

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Gas Research Institute (GRI)


GRI–96/0396.5—Evaluation of Mitigation Methods for Accidental LNG Releases, Volume 5: Using FEM3A for LNG Consequence Analyses. 193.2059; Appendix A to Part 193

International Conference of Building Officials

5360 South Workman Hill Road, Whittier, CA 90601

ICBO, Uniform Building Code, 1994 193.2061; appendix A to part 193

Manufacturers Standardization Society of the Valve and Fitting Industry

5203 Leesburg Pike, Suite 502, Falls Church, VA 22041

MSS-SP-44 Steel Pipe Line Flanges, 1991 192.147; appendix A to part 192

MSS-SP-75 Specification for High-Test Wrought Butt Welding Fittings, 1993. 195.3; 195.118

National Fire Protection Association

1 Batterymarch Park, Quincy, MA 02269–9101, Telephone: (800) 344-3555

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190.11 Added: (a)(1) corrected; (a)(4) and (5) removed; (a)(6) redesignated as (a)(4); (b) amended 28785
190.2057 Amended; (b) and (c)(1) revised 37224
193.2907 (a) and (b) revised (OMB number pending) 27793
195.302 (c)(1) introductory text, (2)(i) introductory text and (i) revised 54592
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### Technical Corrections

- Effective date at 62 FR 67294, eff. 7–6–99: Announced at 60 FR 47246, eff. 7–6–99.
- Regulation at 62 FR 67294.
- Announced at 63 FR 48200, eff. 7–6–99.
- New 195.304 redesignated from 195.306.
- New 195.303 added; 195.306 redesignated from 195.303.
- Amended at 60 FR 47246, eff. 7–6–99.
- Clarification at 60 FR 47246, eff. 7–6–99.
- New 195.304 redesignated from 195.306.
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- New 195.304 redesignated from 195.306.
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