Chapter PSC 134

STANDARDS FOR GAS SERVICE

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PSC 134.01 General. (1) Chapter PSC 134 of the public service commission's departmental rules is part of the Wis. Adm. Code and constitutes a general order of the public service commission, the issuance of which is authorized by ss. 227.014, 196.02, 196.06, 196.10, 196.12, 196.15, 196.16, 196.17, and 196.19, Stats.

(2) The rules making up ch. PSC 134 are designed to effectuate and implement ss. 196.02, 196.03, 196.06, 196.10, 196.12, 196.15, 196.16, 196.17, 196.19, 196.21, 196.22, 196.60, 196.62 and parts of other sections of the Wisconsin statutes.

(3) Nothing in this chapter of the Wisconsin Administrative Code shall preclude the commission's giving special and individual consideration to exceptional or unusual situations or, upon investigation of the facts and circumstances involved, adopting requirements as to individual utilities or services which may be lesser, greater, other than or different from those provided in these rules.

(4) The requirements of ch. PSC 134 shall be observed by all public utilities, both privately and publicly owned, engaged in the manufacture, mixing, purchasing, storage, transmission and/or distribution of gaseous fuel.

(5) The manner of enforcing the rules in ch. PSC 134 is prescribed in s. 196.66, Stats., and such other means as provided in statutory sections administered by the public service commission.

(6) In case of emergency, where public interest requires immediate action without waiting for compliance with the specific terms of these

rules, immediate corrective action shall be taken by the utility, which action, however, shall be subject to review by the public service commission.

(7) Periodic reports to the public service commission are required by Wis. Adm. Code ss. PSC 134.14 (6); PSC 134.17; PSC 134.18 (3); PSC 134.19 (3); PSC 134.25 (4). Individual reports are required by PSC 134.18 (4) and (5).

History; 1-2-56; r. and recr. Register, February, 1959, No. 38. eff. 3-1-59; am. (5). Register, January, 1965, No 109, eff. 2-1-65; renum. (3) to (6) to be (4) to (7), Register, November, 1980, No. 299, eff. 12-1-80.

PSC 134.02 Definitions. The following terms as used in this chapter mean:

(1) APPLIANCE. A gas appliance is any device which utilizes gas fuel to produce light, heat, or power.

(2) COMPLAINT. Complaint as used in this chapter is a statement or question by anyone, whether a utility customer or not, involving a wrong, grievance, injury, dissatisfaction, illegal action or procedure, dangerous condition or action, or utility obligation.

(3) DEMAND. Gas demand means the amount of gas required per unit of time, usually expressed in cubic feet, Btu, or therms per unit of time.

(4) DRY GAS. Dry gas as applied to gas usage means a gas having a moisture and hydrocarbon dew point below any normal temperature to which the gas piping is exposed. As applied to determination of heating value or specific gravity it means the complete absence of moisture or water vapor.

(5) GAS. Gas as used in this chapter is any gas or mixture of gases suitable for domestic or industrial fuel and transmitted or distributed to the user through a piping system. The common types are natural gas, manufactured gas, and liquefied petroleum gas distributed as a vapor with or without admixture of air.

(6) HEATING AND CALORIFIC VALUES. (a) *British thermal unit (Btu)*. A British thermal unit is the quantity of heat that must be added to one avoirdupois pound of pure water to raise its temperature from 58.5°F to 59.5°F under standard pressure.

(b) *Dry calorific value*. The dry calorific value of a gas (total or net) is the value of the total or the net calorific value of the gas divided by the volume of dry gas in a standard cubic foot.

Note: The amount of dry gas in a standard cubic foot is .9826 cu. ft.

(c) *Net calorific value of a gas*. The net calorific value of a gas is the number of British thermal units evolved by the complete combustion, at constant pressure, of one standard cubic foot of gas with air, the temperature of the gas, air, and products of combustion being 60°F and all water formed by the combustion reaction remaining in the vapor state.

Note: The net calorific value of a gas is its total calorific value minus the latent heat of evaporation at standard temperature of the water formed by the combustion reaction.

(d) *Therm*. Therm means 100,000 British thermal units.

(e) *Total calorific value.* Total calorific value of a gas is the number of British thermal units evolved by the complete combustion, at constant pressure, of one standard cubic foot of gas with air, the temperature of the gas, air, and products of combustion being 60°F and all water formed by the combustion reaction condensed to the liquid state.

(7) METER. A meter is an instrument installed to measure the volume of gas delivered through it.

(8) MUNICIPALITY. A municipality is any town, city or village.

(9) PRESSURE. (a) *Pressure.* Pressure unless otherwise stated is expressed in pounds per square inch above atmospheric pressure, i.e. gauge pressure. (Abbreviation—psig).

(b) *Standard pressure.* See (11) (c) below.

(c) *Standard service pressure.* Standard service pressure is the gas pressure which a utility undertakes to maintain on the meters of all customers except the meters of customers utilizing high-pressure service.

(10) PUBLIC UTILITY. Public utility is defined in s. 196.01, Stats., and ch. PSC 134 applies to those supplying public utility gas service.

(11) STANDARDS. (a) *Specific gravity of a gas.* The specific gravity of a dry gas is the ratio of the molecular weight of the dry gas or gas mixture to the molecular weight of dry air. This is the dry specific gravity.

(b) *Standard cubic foot of gas.* A standard cubic foot of gas is the quantity of any gas that at standard temperature and under standard pressure will fill a space of 1 cu. ft. when in equilibrium with liquid water.

(**Note:** According to Dalton's Law, this is equivalent to stating that the partial pressure of the gas is: 30—0.522 = 29.478 inches of mercury column).

(c) *Standard pressure.* Standard pressure is the absolute pressure of pure mercury 30 inches in height at 32°F and under standard gravity (Gravity 32.174 ft. per sec.). (Equivalent to 14.735 lbs. per sq. in.).

(d) *Standard temperature.* Standard temperature is 60°F based on the international temperature scale.

(12) UNMEASURED GAS. Unmeasured gas is gas which has not been measured by a meter.

History: 1-2-56; r. and recr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.03 Service. Every gas utility shall furnish reasonably adequate service and facilities at the rates filed with the commission and subject to these rules and the rules of the utility filed with this commission which are applicable thereto and not otherwise. The utility shall be operated in such manner as to obviate so far as reasonably practicable, undesirable effects upon the operation of standard services, standard utilization equipment, equipment of the utility, and upon the service and facilities of other utilities and agencies.

History: 1-2-56; r. and recr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.04 Schedules to be filed with commission. The schedules of rates and rules shall be filed with the commission by the utility and shall be classified, designated, arranged, and submitted so as to conform to the requirements of current tariff or rate schedule circulars and special instructions which have been and may from time to time be issued by the commission. Provisions of the schedules shall be definite and so stated as to minimize ambiguity or the possibility of misinterpretation, and shall include, together with such other information as may be deemed pertinent, the following:

(3) Forms of standard contracts required of customers for the various types of service available.

(4) If service to other utilities or municipalities for resale is furnished at a standard filed rate, either a copy of each contract or the standard contract form together with a summary of the provisions of each signed contract. The summary shall show the principal provisions of the contract and shall include the name and address of the customer, the points where gas is delivered, rate, term, minimums, load conditions, heating value of gas, pressures, and any special provisions such as rentals.

(5) Copies of special contracts for the purchase, sale, or interchange of gas.

(6) List of villages, cities, and unincorporated communities where urban rates are applicable, and towns in which service is furnished.

(7) Definitions of classes of customers.

(8) Extension rules for extending service to new customers indicating what portion of the extension or cost thereof will be furnished by the utility; and if the rule is based on cost, the items of cost included.

(9) Type of construction required of the customer if different from requirements in ch. PSC 135, Wis. Adm Code.

(10) Designation of such portion of the service facilities as the utility furnishes, owns, and maintains.

(11) Rules with which prospective customers must comply as a condition of receiving sevice, and the terms of contracts required.

(12) Rules governing the establishment of credit by customers for payment of service bills.

(13) Rules governing disconnecting and reconnecting service.

(14) Notice required from customer for having service discontinued.

(15) Rules covering temporary, emergency, auxiliary, and standby service.

(16) Rules covering the type of equipment which may or may not be connected.

(17) The list of service areas and the rates shall be filed in such form as to facilitate ready determination of the rates available in each municipality and in such unincorporated communities as have service at urban

rates. If the utility has various rural rates, the areas where the same are available shall be indicated.

History: 1-2-56; r. and recr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.05 Information available to customers. (1) Each utility shall have available in its offices where payments are received, copies of its rates and rules applicable to the locality. The rates and rules shall be available for customer inspection and reasonable notice as to their availability shall be provided to customers.

(2) Each gas utility, for every municipality in which it serves, shall provide in the respective telephone directories a telephone listing by which the utility can be notified during a 24-hour day of any utility service deficiency or emergency which may exist.

(3) Where a second language is common in a particular area served by the utility and so identified by the commission, all rules pertaining to billing and credit shall be available upon customer request for distribution in English and that second language in every business office of the utility in that area accessible to the public and where customer payments are received.

(4) Each utility shall provide written notice to its residential customers annually, and a written notice to all new residential customers, at a minimum, of the rules on deposits, payment options including deferred payment agreements and budget billing, disconnection and dispute procedures; of the availability of information on energy conservation practices, of the availability of a clear, concise record of the customer's actual natural gas consumption (or actual degree-day adjusted natural gas consumption) for each billing period during the prior 12 months or the actual number of months that the customer has lived at that location if less than 12 months, and of the availability of agencies or programs which may provide financial aid assistance or counseling; and contain a reply procedure to allow customers an opportunity to advise the utility of any special circumstances, such as the presence of infants or elderly persons or the use of human life sustaining equipment, and to advise the utility to contact a specific third party agency or individual prior to any disconnection action being taken.

History: 1-2-56; r. and recr. Register, February, 1959, No. 38, eff. 3-1-59; renum. PSC 134.05 to be PSC 134.05 (1); cr. (2), Register, January, 1965, No. 109, eff. 2-1-65; am. (1), renum. (2) to be (3) and cr. (2) and (4), Register, January, 1975, No. 229, eff. 2-1-75; am. Register, March, 1979, No. 279, eff. 4-1-79; am. (4), Register, October, 1980, No. 298, eff. 11-1-80.

PSC 134.061 Deposits. (1) NEW RESIDENTIAL SERVICE. A utility shall not require a cash deposit or other guarantee as a condition of new service unless a customer has an outstanding account balance with the utility which accrued within the last 6 years, and which at the time of the request for new service remains outstanding and not in dispute. (See Wis. Adm. Code section PSC 134.064.)

(2) EXISTING RESIDENTIAL SERVICE. A utility shall not require a cash deposit or other guarantee as a condition of continued service unless either or both of the following circumstances apply:

(a) The utility has shut off or discontinued the service of the customer within the last 12-month period for violation of the utility's filed rules or for nonpayment of a delinquent service account not currently in dispute.

(b) Subsequent credit information indicates that the initial application for service was falsified or incomplete to the extent that a deposit would be required under this section.

(3) NEW COMMERCIAL SERVICE. (a) If the credit of an applicant for service has not been established satisfactorily to the utility, the applicant may be required to deposit a sum not exceeding the estimated gross bills for any 2 consecutive billing periods selected by the utility.

(b) In determining whether an applicant for service has satisfactorily established its credit, the utility shall consider the following factors before requiring a security deposit.

1. Credit information from credit reporting services;

2. Letter of credit from a financial institution or another utility;

3. Applicant's business characteristics, such as type of business, length of time the applicant has operated, the applicant's business experience and knowledge, and estimated size of the applicant's bills.

4. Assets of the business;

5. The financial condition of the business, as indicated in a financial statement.

(c) The utility shall notify the applicant within 30 days of the request for service as to whether a deposit will be required. The 30-day period shall begin from the date the applicant provides all requested relevant information to the utility. If no request for a deposit is made within this period, no deposit shall be required, except under the provisions of sub. (4) (a). If a request for a deposit is made, the applicant must be given at least 20 days to provide payment, or guarantee, or to establish an installment payment agreement.

(d) The deposit of a commercial customer shall be refunded after 24 consecutive months of prompt payment. Payment is considered prompt if made prior to notice of disconnection for nonpayment not in dispute.

(4) EXISTING COMMERCIAL SERVICE. An existing commercial customer may be required to furnish a deposit if the customer has not made prompt payment of all bills within the last 24 consecutive months.

(b) When the utility requests a deposit of an existing commercial customer, the customer shall have 20 days to provide the deposit, guarantee, or to establish an installment payment agreement.

(c) Refund of the deposit of an existing commercial customer shall be made in accordance with s. PSC 134.061 (3) (d).

(5) CONDITIONS OF DEPOSIT. The maximum deposit for a new commercial or residential account shall not exceed the highest estimated gross bill for any 2 consecutive billing periods selected by the utility.

The maximum deposit for an existing commercial or residential account shall not exceed the highest actual gross bill for any 2 consecutive months within the preceding 12 month review period as determined by the utility.

(6) INTEREST. Deposits for commercial or residential service shall bear interest of at least 8% payable from the date of deposit to the date of refund or discontinuance of service, whichever is earlier.

(7) REVIEW. The utility shall review the payment record of each residential utility customer with a deposit on file at 12-month intervals. The utility shall not require or continue to require a cash deposit unless a deposit is required under the provisions of s. PSC 134.061 (2).

(8) REFUND. Any deposit or portion thereof refunded to a commercial or residential customer shall be refunded by check unless both the customer and the utility agree to a credit on the regular billing, or unless sub. (9) applies.

(9) ACCRUED INTEREST. Upon termination of commercial or residential service, the deposit, with accrued interest, shall be credited to the final bill and the balance shall be returned promptly to the customer.

(10) WRITTEN EXPLANATION. A utility shall not require any commercial or residential customer to pay a deposit or establish a guarantee in lieu of deposit without explaining, in writing if requested, why that deposit is being required.

(11) REFUSAL OF SERVICE. Commercial or residential service may be refused or disconnected for failure to pay a deposit request subject to the rules pertaining to disconnection and refusal of service. (s. PSC 134.062).

(12) GUARANTEE TERMS AND CONDITIONS. (a) The utility may accept, in lieu of cash deposit, a contract signed by a guarantor satisfactory to the utility whereby payment of a specified sum not exceeding the cash deposit requirement is guaranteed. The term of such contract shall be for no longer than 2 years, but shall automatically terminate after the commercial or residential customer has closed its account with the utility, or at the guarantor's request upon 30 days' written notice to the utility.

(b) Upon termination of a guarantee contract or whenever the utility deems same insufficient as to amount of surety, a cash deposit or a new or additional guarantee may be required upon reasonable 20-day written notice to the customer. The service of any customer who fails to comply with these requirements may be disconnected upon 8 days' written notice, subject to sub. (13) for a residential customer or the establishment of an installment payment agreement for a commercial customer.

(c) The utility shall mail the guarantor copies of all disconnect notices sent to the customer whose account he has guaranteed unless the guarantor waives such notice in writing.

(13) DEFERRED PAYMENT. (a) In lieu of cash deposit or guarantee, an applicant for new residential service who has an outstanding account accrued within the last 6 years with the same utility shall have the right to receive service from that utility under a deferred payment agreement as defined in s. PSC 134.063 for the outstanding account.

(b) A commercial customer or applicant for commercial service of which a deposit is requested shall have the right to receive service under an installment payment agreement.

(14) APPLICABILITY. The rules in subs. (12) and (13) of this section are not applicable to deposits or guarantees made in connection with the financing of extensions or other equipment.

History: Cr. Register, January, 1975, No. 229, eff. 2-1-75; am. Register, November, 1980, No. 299, eff. 12-1-80.

PSC 134.062 Disconnection and refusal of service. (1) (a) In no circumstances will the cumulative time before notice of disconnection be less than 20 days after the date of issuance of the bill and an account may be deemed delinquent for the purpose of disconnection after such period has elapsed.

(b) At least 8 calendar days prior to disconnection, the utility shall give written disconnect notice upon a form which must be in the tariff of the utility filed with the public service commission and which conforms to the requirements of (8) unless excepted elsewhere.

(c) When a customer, either directly or through the public service commission, disputes a disconnection notice the utility shall investigate any disputed issue and shall attempt to resolve that issue by negotiation. During this investigation and negotiation, utility service shall not be disconnected over this matter.

(d) If a disputed issue cannot be resolved pursuant to s. PSC 134.064 (1), the utility shall inform the customer of the right to contact the public service commission.

(2) Utility service may be disconnected for any of the following reasons, provided that if the commission declares a winter emergency to be in effect, there must be reasonable grounds to believe that such disconnection will not, under the circumstances, endanger human health or life:

(a) Failure to pay a delinquent account or failure to comply with the terms of a deferred payment agreement (See s. PSC 134.063.).

(b) Violation of the utility's rules pertaining to the use of service in a manner which interferes with the service of others or to the operation of nonstandard equipment, if the customer has first been notified and provided with reasonable opportunity to remedy the situation.

(c) Failure to comply with deposit or guarantee arrangements as specified in s. PSC 134.061.

(d) Diversion of service around the meter.

(e) Connecting or having connected a natural gas outdoor lighting fixture as specified in PSC 136.02.

(f) Connecting or causing to be connected a device or use of gas considered to be a nonessential use of natural gas. This rule applies only to devices or purposes connected after the effective date of the rule as specified in PSC 136.05.

(g) Failure to comply with Wisconsin statute, commission rule, or order pertaining to conservation or availability of service. Refusal or failure to permit authorized utility personnel to read the meter at least once every 6 months in order to determine actual usage. The six-month period begins with the date of the last meter reading.

(3) A public utility may disconnect utility service without notice where a dangerous condition exists for as long as the condition exists.

(4) Service may be denied to any customer for failure to comply with applicable requirements of this section, or of the utility's rules, or if a dangerous or unsafe condition exists on the customer's premises.

(5) Utility service may not be disconnected or refused for any of the following reasons:

(a) Nonpayment of a delinquent account over 6 months old where collection efforts have not been made within that period of time unless the passage of additional time results from other provisions herein or from good faith negotiations or arrangements made with the customer.

(b) Delinquency in payment for service by a previous occupant of the premises to be served other than a member of the same household residing at the same premises.

(c) Failure to pay for merchandise or charges for non-utility service billed by the utility.

(d) Failure to pay for a different type or class of utility service.

(e) Failure to pay the account of another customer as guarantor thereof.

(f) Failure to pay charges arising from any underbilling occurring more than one year prior to the current billing and due to any misapplication of rates.

(g) Failure to pay charges arising from any underbilling occurring more than one year prior to the current billing and due to any faulty metering.

(h) Failure to pay an estimated bill other than a bill rendered pursuant to an approved bimonthly meter reading plan unless the customer upon request refuses to permit the reading of the meter during normal business hours.

(6) A utility shall not disconnect any residential service without notifying the county department of health and social services at least 5 calendar days prior to the scheduled disconnection, if the customer or responsible person has made a written request for this procedure to the utility. The customer shall be appraised of this right upon application for service.

(7) Notwithstanding any other provision of this section, a utility may not disconnect service to a residential customer if disconnection will aggravate an existent medical emergency of the customer, a member of his family or other permanent resident of the premises where service is rendered and if the customer conforms to the procedure described in par. (a), below.

(a) A utility shall postpone the disconnection of service for 21 days to enable the customer to arrange for payment, if the customer produces a licensed Wisconsin physician's statement or notice from a public health or social services official which identifies the medical emergency and specifies the period of time during which disconnection will aggravate the circumstances. The postponement may be extended once by renewal of the certificate or notice. No further extension of time shall be granted except upon a showing by the customer of the existence of extraordinary circumstances and further that he has exercised due diligence in meeting the emergency as evidenced in part by close and continuous communication with the utility.

(b) During the period service is continued under the provisions of this subsection, the customer shall be responsible for the cost of residential utility service. However, no action to disconnect that service will be undertaken until expiration of the period of continued service.

(c) If there is a dispute concerning an alleged existent medical emergency, either party shall have the right to an informal review by the public service commission staff. Pending a decision after informal review, residential utility service shall be continued provided that the resident has submitted a statement or notice as set forth in par. (a) of this subsection.

(8) (a) A utility shall not disconnect service unless written notice by first class mail is sent to the customer or personally served at least 8 calendar days prior to the first date of the proposed disconnection. Notice shall be sent to the account name and address, and to the address where service is provided, if different. If disconnection is not accomplished on or before the 15th day after the first notice date, a subsequent notice must be left on the premises not less than 24 hours nor more than 48 hours prior to disconnection.

(b) The utility shall make a reasonable effort to have a personal or telephone contact with the customer prior to disconnection.

(c) Disconnection notice shall be given upon a form approved by the Commission, and shall contain the following information:

1. The name and address of the customer and the address of service, if different.

2. A statement of the reason (s) for the proposed disconnection of service and that disconnection will occur if the account is not paid, or if arrangement is not made to pay the account under deferred payment agreement, or if other suitable arrangements are not made, or if equipment changes are not made. If disconnection of service is to be made for default on a deferred payment agreement, the notice shall include an explanation of the acts of the customer which are considered to constitute default.

3. A statement that the customer should communicate immediately upon receipt of the notice with the utility's designated office, listing a telephone number, if he disputes the notice of delinquent account, if he wishes to negotiate a deferred payment agreement as an alternative to disconnection, if any resident is seriously ill, or if there are other extenuating circumstances.

4. A statement that residential utility service will be continued for up to 21 days during serious illness if the account holder submits a statement or notice pursuant to (7).

5. A statement that the customer may appeal to the public service commission staff in the event that the grounds for the proposed discon-

nection or the amount of any disagreement remains in dispute after the customer has pursued the available remedies with the utility.

(9) (a) Service shall not be disconnected on a day, or on a day immediately preceding a day, when the business offices of the utility are not available to the public for the purpose of transacting all business matters unless the utility provides personnel which are readily available to the customer 24 hours per day to evaluate, negotiate or otherwise consider the customer's objection to the disconnection as provided under s. PSC 134.064 and proper service personnel are readily available to restore service 24 hours per day.

(b) If a residential service which has been disconnected has not been restored to service within 24 hours after the time of the disconnection, the utility shall inform the local law enforcement department of the billing name and the service address and that a threat to health and life might exist to persons occupying the premises.

History: Cr. Register, January, 1975, No. 229, eff. 2-1-75; am. (1) (a) and (5) (a), Register, December, 1975, No. 240, eff. 1-1-76; am. (2) (intro.), Register, March, 1979, No. 279, eff. 4-1-79; emerg. cr. (2) (g), eff. 1-26-80; cr. (2) (f), Register, January, 1980, No. 289, eff. 2-1-80; cr. (2) (e), Register, February, 1980, No. 290, eff. 3-1-80; cr. (2) (g), Register, July, 1980, No. 295, eff. 8-1-80; emerg. cr. (10), eff. 12-17-81; cr. (2) (h), Register, September, 1982, No. 321, eff. 10-1-82.

PSC 134.063 Deferred payment agreement. The utility is required to offer deferred payment agreements only to residential accounts.

(1) Every deferred payment agreement entered into due to the customer's inability to pay the outstanding bill in full shall provide that service will not be discontinued if the customer pays a reasonable amount of the outstanding bill and agrees to pay a reasonable portion of the remaining outstanding balance in installments until the bill is paid.

(2) For purposes of determining reasonableness under these rules the parties shall consider the:

(a) Size of the delinquent account.

(b) Customer's ability to pay.

(c) Customer's payment history.

(d) Time that the debt has been outstanding.

(e) Reasons why the debt has been outstanding.

(f) Any other relevant factors concerning the circumstances of the customer.

(3) A deferred payment agreement offered by a utility shall state immediately preceding the space provided for the customer's signature and in bold face print at least 2 type sizes larger than any other used thereon, that "IF YOU ARE NOT SATISFIED WITH THIS AGREEMENT, DO NOT SIGN. YOU HAVE THE RIGHT TO MAKE A COUNTER OFFER AND, IF IT IS REJECTED, YOU HAVE THE RIGHT TO APPEAL THIS PROPOSED AGREEMENT TO THE PUBLIC SERVICE COMMISSION OF WISCONSIN, DURING WHICH TIME THE UTILITY MAY NOT DISCONNECT YOUR SERVICE. THIS DOES NOT RELIEVE YOU FROM THE OBLIGATION TO PAY BILLS THAT ARE INCURRED AFTER COMMENCEMENT OF DISPUTE PROCEDURES. IF YOU DO SIGN THIS AGREEMENT

YOU GIVE UP YOUR RIGHT TO DISPUTE THE AMOUNT DUE UNDER THE AGREEMENT EXCEPT FOR THE UTILITY'S FAILURE OR REFUSAL TO FOLLOW THE TERMS OF THIS AGREEMENT."

(4) A deferred payment agreement shall not include a finance charge.

(5) If an applicant for utility service has not fulfilled terms of a deferred payment agreement, the utility shall have the right to disconnect pursuant to disconnection of service rules (PSC 134.062) and under such circumstances, it shall not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

(6) Payments made by a customer in compliance with a deferred payment agreement, shall be first considered made in payment of the previous account balance with any remainder credited to the current bill.

(7) If a deferred payment agreement cannot be reached, and if the customer's proposed deferred payment agreement is unacceptable to the utility, the utility shall inform the customer in writing why the customer's offer was not acceptable.

History; Emerg. cr. eff. 1-21-75; cr. Register, January, 1975, No. 229, eff. 2-1-75; am., Register, March, 1979, No. 279, eff. 4-1-79.

PSC 134.064 Dispute procedures. (1) Whenever the customer disputes the utility's request for a deposit or other guarantee, or advises the utility's designated office that all or any part of any billing as rendered is in dispute, or that any matter related to the disconnection or refusal of service is in dispute, the utility shall:

(a) Investigate the dispute promptly and completely.

(b) Advise the customer of the results of the investigation.

(c) Attempt to resolve the dispute.

(d) Provide the opportunity for the customer to enter into a deferred payment agreement when applicable in order to settle the dispute.

(2) After the customer has pursued the available remedies with the utility, he may request that the public service commission staff informally review the disputed issue and recommend terms of settlement.

(a) A request for informal review may be made in any reasonable manner such as by written notice or telephone request directed to the public service commission. By telephone or written notice the public service commission staff may request the utility to investigate the dispute.

(b) There must be at least 5 days between the date the commission staff telephones or mails written notice of terms of settlement after informal review, and any subsequent disconnection.

(3) Any party to the dispute after informal review may make a written request for a formal review by the commission. Such request must be made within 5 days of the date the commission staff telephones or mails written notice of terms of settlement after informal review. If written confirmation of the staff telephone notice is requested and mailed, the 5 day period begins from the date of that mailing.

(a) Within 10 days from the time such a request is made, the commission shall decide on the basis of the information it has received from the staff whether to hold a hearing on the matter and shall inform both parties of its decision.

(b) If the commission decides to conduct formal hearing on the dispute, the customer shall be required to pay 50% of the bill or deposit in dispute to the utility or post bond for that amount on or before date of hearing. Such payment or bond may be waived by the commission for good cause shown. Failure to pay the specified amount before hearing will constitute waiver by the customer.

(c) Such a hearing shall conform to the procedures described in ss. 196.26 to 196.34, Stats.

(d) Any such hearing shall be held not less than 10 days following a notice of hearing and a decision thereon shall be rendered following the conclusion of the hearing.

(4) Utility service shall not be disconnected or refused because of any disputed matter while the disputed matter is being pursued in accordance with the provisions of this section. In no way does this relieve the customer from obligation of paying charges which are not in dispute.

History: Emerg. cr. eff. 1-21-75; cr. Register, January, 1975, No. 229, eff. 2-1-75; am. (1), (3) (b) and (4), Register, December, 1975, No. 240, eff. 1-1-76; am. (1) (intro.), Register, March, 1979, No. 279, eff. 4-1-79; emerg. am. (2) (a) and (b) and (3), eff. 12-17-81; am. (2) (a) and (b) and (3), Register, July, 1982, No. 319, eff. 8-1-82.

PSC 134.10 Service on customer's premises. (1) All changes in the heating value standard, all changes in pressure and specific gravity greater than the allowable variation, and changes in the composition of the gas which would materially affect the operation of the customer's appliances must be accompanied by a general inspection and adjustment of all appliances that would be affected by the changes. The utility shall make such adjustments and such changes to all customers' appliances that are connected to an interior piping system at the time of the change as may be necessary in order that the appliance may operate as efficiently and give as good service as was possible before the change. This should be done promptly and without cost or unnecessary inconvenience to the customer.

(2) If in connection with a service change specified in (1) above, a piece of properly operating utilization equipment cannot be adjusted so that it will operate satisfactorily and if it must be replaced in its entirety the utility shall share equitably in the cost of changing the equipment. The change in customer's equipment should be made with the greatest possible economy to the customer, and final settlement made at the time of the change. A satisfactory settlement would be payment by the utility to the customer of the remaining value of the customer's equipment and the cost of removing the old and installing in the same position substantially equal equipment which replaces it.

(3) (a) Each utility shall adopt and file with this commission a policy for inspection of customer's appliances. The filed rule need not include the inspection and adjustment of special industrial equipment, which should be checked by persons more familiar with the equipment. The filed rule shall provide that customers having such equipment are to be notified.

(b) Each gas utility shall establish an educational and inspection program designed to inform customers and assist the general public in the proper and efficient operation and maintenance of gas burning equipment. Such program shall advise customers to have heating equipment checked annually and offer energy saving suggestions to customers.

(c) Whenever a gas utility is required to enter a customer's premises to re-establish service to relight applicances due to a non-emergency interruption of service, an inspection of the burner ignition and flame appearance shall be made on each appliance which is relit to check for safety and efficient operation. The utility will be prepared to advise the customer relative to the safety and efficiency of connected appliances.

History: 1-2-56; r. and recr. Register, February, 1959, No. 38, eff. 3-1-59; am. (3), Register, March, 1977, No. 255, eff. 4-1-77.

PSC 134.11 Meters and control equipment. (1) Where possible to do so, all gas quantities required to be reported to the commission shall be metered.

(2) All gas sold to customers shall be measured by commercially acceptable measuring devices owned and maintained by the utility. The maintenance of the accuracy of the meters shall be the responsibility of the utility.

(3) Every reasonable effort shall be made to measure at one meter location all gas quantities necessary for billing the customer.

(4) All gas customers of the same type, pressure, and/or volume classification shall have their gas metered with instruments having like characteristics and at the same pressure base, except that the commission may approve the use of instruments of different types if their use does not result in unreasonable discrimination.

(5) Any regulators or equipment used to provide service in accordance with commission or filed utility rules and rates shall be commercially acceptable devices owned and maintained by the utility.

(6) A temperature-compensating meter shall be used whenever a gas meter is subject to the elements of the weather or wide variations in temperature. All present non-compensating installations subject to the elements of the weather and wide variations in temperature shall be changed so that 100% compliance will be attained by the end of the first complete testing cycle as provided in s. PSC 134.30 (1).

History: 1-2-56; r. and recr. Register, February, 1959, No. 38, eff. 3-1-59; cr. (6), Register, January, 1965, No. 109, eff. 2-1-65.

PSC 134.12 Meter readings and billing periods. Reading of all meters used for determining charges to customers shall be scheduled monthly, bimonthly, quarterly, or semi-annually. An effort shall be made to read meters on corresponding days of each meter-reading period. The meter-reading date may be advanced or postponed not more than 5 days without adjustment of the billing for the period. Bills for service shall be rendered within 40 days from the reading of the meter except as may be otherwise specifically authorized by the commission. The utility may permit the customer to supply the meter readings on a form supplied by the utility, provided a utility representative reads the meter at least once each 6 months and when there is a change of customer. The utility shall make reasonable efforts to read the meters of customers who cannot be available during normal business hours.

History: 1-2-56; r. and recr. Register, February, 1959, No. 38, eff. 3-1-59; am. Register, September, 1982, No. 321, eff. 10-1-82.

PSC 134.13 Billing. (1) (a) Each bill including the customer's receipt, provided by the following investor-owned utilities:

Lake Superior District Power Company

Madison Gas and Electric Company

Northern States Power Company

Superior Water, Light and Power Company

Wisconsin Fuel and Light Company

Wisconsin Gas Company

Wisconsin Natural Gas Company

Wisconsin Southern Gas Company

Wisconsin Power and Light Company

Wisconsin Public Service Corporation

shall show for each meter the following information:

1. The customer name, billing address and service address (if different from the billing address).

2. For residential customers in multi-unit buildings, current meter identification information or number and account number.

3. The present and last preceding meter readings.

4. The present and last preceding meter reading dates.

5. The next scheduled meter reading date.

6. The number of days in the billing period.

7. The number of units consumed.

8. The class of service with clear explanation of codes and abbreviations.

9. The rate schedule under which the bill is calculated including the itemized calculations of the rate schedule component including, but not limited to, such items as customer charge, energy blocks, demand charges, minimum bills and all other billing factors necessary for the customer to check the calculation of the bill.

10. Clear itemized adjustment clause bill calculation.

11. Amount subject to tax, tax rate, and tax billed.

12. Clear itemization of the amount of the bill for the present billing period, any unpaid balance from previous billing periods and any late payment charges.

13. Clear itemization of other utility charges and credits.

14. A statement will be printed on each bill indicating to the customer that the utility will, upon customer request, provide the information and assistance necessary for the customer to evaluate fuel consumption and conservation. Upon receiving such request, the utility shall provide consumption and degree day information by billing periods for at least the last year and information and instructions needed by the customer to make consumption comparisons and evaluate his or her conservation ef-

forts. In order to assist customers in their conservation monitoring, the utility will provide degree day information with each monthly bill.

15. Bills rendered without an actual meter reading shall be specifically marked as estimated.

16. Each utility subject to the rules in (1) (a) will file a plan for implementation as soon as possible and no later than 60 days from date of publication. The plans shall include a list of uniform bill codes developed by the utilities, to be approved by the commission.

(b) Each bill including the customer's receipt rendered by gas utilities not included in par. (a), shall show the present and last preceding meter readings, the date of the present reading, the number of units consumed, the class of service if other than residential, and the rate schedule under which the bill is calculated. In lieu of including the rate schedule on the bill the utility may, whenever a rate change becomes effective and at least twice a year, supply each customer with the schedule of rates at which the bills are calculated and any other rates that might be applicable. Bills rendered at rates requiring the measurement of a number of different factors shall show all data necessary for the customer to check the calculation of the bill. All monthly adjustment clause factors necessary for a customer to check the calculation of the bill shall be included on the monthly bill. Minimum and estimated bills shall be distinctly marked as such. Estimated bills are bills rendered without actual meter readings.

(c) Merchandise and service repair work charges shall not be included on utility service bills.

(d) The utility may include on the utility service bill charges to the customer resulting from other services, materials or work provided by the utility as a result of commission-approved conservation and alternative energy programs. The charges shall be listed individually on the bill and the customer shall be permitted to include such payment in his or her payment for gas utility service. Any partial payments will be applied first to the amount due for utility service and the remainder to the other charges.

(e) The commission may authorize the utility to make late payment charges to a customer's utility service bill that is not paid in full within 20 days following issuance of the bill. The late payment charge may be either a one-time charge as provided in par. (f) or a monthly charge as provided in par. (g). The utility shall receive approval from the commission of the method it desires to use and shall not change methods without commission approval.

(f) If the utility is authorized to make a one-time late payment charge, such charge shall comply with the following requirements:

1. The bill shall clearly indicate the amount of the late payment charge and the date after which the late payment charge shall be applied.

2. Late payment charges shall be applied no sooner than 20 days after the date of issuance of the bill.

3. The amount of the late payment charge shall be 3% of the bill, except a minimum charge of 30¢ shall apply.

4. Late payment charges shall be applied to all customer classes and rate classifications.

5. The utility shall not waive any properly applied late payment charges.

6. A late payment shall be applied only once to any given amount outstanding.

(g) If the utility is authorized to make monthly late payment charges, such charges shall comply with the following requirements:

1. The amount of the charge shall be no more than 1-½% per month and shall be filed with and approved by the commission before it can be applied.

2. The late payment charge shall be applied to the total unpaid balance for utility service, including unpaid late payment charges.

3. The late payment charge shall be applied no sooner than 20 days after the date of issuance of the bill.

4. The late payment charge shall be applied to all customer classes and rate classifications.

5. If a customer disputes a bill for utility service or portion thereof and does not pay the disputed bill in full within 20 days following issuance of the bill, the late payment charge shall be applied only to that portion of the disputed bill later found to be correct and payable to the utility.

6. The utility may not waive any properly applied late payment charge.

7. No additional late payment charge may be applied to a delinquent account for utility service after the date on which the delinquent account was written off by the utility as uncollectable.

8. If a utility charges the type of late payment charge or initiates a late payment charge, the new charge shall apply only to utility service provided after the effective date of the change or initiation.

(2) (a) If the billing period is longer or shorter than allowed in s. PSC 134.12, the bill shall be prorated on a daily basis unless other provision is made in the utility's filed rules.

(b) If the utility cannot read the meter at the end of each billing period, or if the customer requests it, the utility shall leave meter-reading forms at the premises for completion by the customer. If no form is left or the form is not returned in time for the billing operation, a minimum or estimated bill may be rendered. In cases of emergency, the utility may render minimum or estimated (average) bills without reading meters or supplying meter-reading forms to customers. Only in unusual cases or when approval is obtained from the customer shall more than 3 consecutive estimated bills be rendered.

(c) If meter reading is not scheduled on a monthly basis, the utility shall supply customers with meter-reading forms for the periods when the meter is not scheduled to be read by the utility. Customers shall not be required to provide these meter readings. If the customer informs the utility he or she does not desire to supply a reading or if the form is not returned in time for the billing operation, a minimum or estimated bill may be rendered.

(d) When an actual meter reading indicates that a previous estimated bill was abnormally high or low the utility shall calculate the bill for the entire period as if use of service was normally distributed throughout the period. The previous estimated charge shall be deducted from the recomputed total. If there is evidence to indicate that actual use was not uniform throughout the period, the billing shall be adjusted according to available information.

(3) (a) Credits due a customer because of meter inaccuracies, errors in billing, or misapplication of rates shall be shown separately and identified.

(b) The original billing rendered because of meter inaccuracy, or errors in billing, shall be separated from the regular bill and the charges explained in detail.

(4) Each bill for service shall be computed at the proper filed rate and the rate used shall be the cheapest applicable rate based on 12 months' use of service. If the customer's use is such that it is difficult to be certain what rate should be applied until there has been 12 months' use, the billing shall be adjusted on the first bill following the end of the 12 month use period.

(a) This rule does not prohibit contracts having terms longer than 1 year but does require that the rates paid under such contracts be the utility's lowest applicable rates on file with the commission.

(b) Where a customer is eligible to take service under more than one rate schedule the utility shall inform the customer how to select the rate that results in the lowest cost of service, based on 12 months' service and on the information at hand.

(c) The customer shall be informed of the selection of a rate every 12 months, whenever there is a change in rates that would affect the customer and at any other time the customer so requests.

(d) Subsection (4) (a), (b) and (c) applies to service as it is being supplied. If the customer could reduce his or her bills by installing equipment, combining or separating services, he or she should be notified, but no change in rates shall be made until the customer makes the necessary changes.

(5) All utilities listed in (1) (a) shall bill on a "therm" basis. Other utilities may base their rates on either a volumetric basis or a "therm" basis but permission must be obtained from this commission to change any rate from one method to another. The unit of service on a volumetric basis shall be the cubic foot. If the volume billed is at a different pressure and/or temperature base than the registered volume, the rate shall specify the billing pressure and temperature. The "therm" billing unit shall be 100,000-British thermal units of total dry heating value. Where therm billing is used, the heating value shall be the average for the billing period or a filed lesser amount. Adjustment of volumes or therms billed shall not be made because of the delivery of standby or peak shaving gas without commission approval.

(6) Each utility shall offer a budget payment plan to all prospective and existing residential customers and to all commercial accounts for which the primary purpose of the service is to provide for residential living, subject to the following minimum requirements.

(a) A budget payment plan tariff shall be on file with the public service commission, applicable only to charges for utility services under PSC jurisdiction.

(b) A budget payment plan may be established at any time of the year. The budget amount shall be calculated on the basis of the estimated consumption and estimated applicable rates through the end of the budget year. If the budget year is a fixed year, then prospective and existing customers requesting a budget payment plan after the start of the fixed year will have their initial monthly budget amount determined on the basis of the number of months remaining in the current budget year.

(c) An applicant for a budget plan shall be informed at the time of application and an existing budget plan customer on at least a quarterly basis, that budget amounts shall be reviewed and changed every 6 months if necessary, in order to reflect current circumstances. Adjustments to the budget amount shall be made with the objective that the customer's underbilled or overbilled balance at the end of the budget year shall be less than one month's budget amount.

(d) Customers on the budget payment plan shall be notified of adjustments by means of a bill insert, a message printed on the bill itself, or both. When an adjustment is made to a budget payment amount, the customer shall be adequately informed of the adjustment at the same time the bill containing the adjustment is rendered.

(e) Customers who have arrearages shall be allowed to establish a budget payment plan by signing a deferred payment agreement for the arrears, according to the provisions of s. PSC 134.063.

Note: Provisions of PSC 134.13 (6) (e) have been incorporated into PSC 134.13 (6) (c) and (d).

(f) Budget payment plans shall be subject to the late payment charge provisions of sub. (1) (f) and (g). In addition, if a budget payment is not paid the customer shall be appropriately notified with the next billing. If proper payment is not received subsequent to this notification, the next regular billing may effectuate the removal of the customer from the budget payment plan and reflect the appropriate amount due.

(g) At the end of a budget year, if an underbilled or overbilled balance exists in the account, the balance shall be handled as follows:

1. A customer's debit balance will be paid in full or, at the customer's option, on a deferred basis.

2. A customer's credit balance will be applied against the customer's account or, at the customer's option, a refund shall be made.

History: 1-2-56; r. and recr. Register. February, 1959, No. 38, eff. 3-1-59; am. (6), Register, January, 1965, No. 109, eff. 2-1-65; r. and recr. (1), Register, August, 1976, No. 248, eff. 9-1-76; am. Register, March, 1979, No. 279, eff. 4-1-79; am. (1) and (5), Register, October, 1980, No. 298, eff. 11-1-80; am. (6), Register, November, 1980, No. 299, eff. 12-1-80; renum. (1) (d) to be (1) (f) and am. (intro)., cr. (1) (d), (e) and (g) and am. (6) (f), Register, September, 1981, No. 309, eff. 10-1-81.

PSC 134.14 Adjustment of bills. (1) Whenever a meter is found to have an error of more than 3% fast as determined in the manner specified in s. PSC 134.28 under any load condition, a recalculation of bills for service shall be made for the period of inaccuracy assuming an inaccuracy equal to the maximum fast percentage. The recalculation shall be made on the basis that the service meter should be 100% accurate.

(2) If the period of inaccuracy cannot be determined, it shall be assumed that the full amount of inaccuracy existed during the last half of the period since the previous test was made on the meter; however, the period of accuracy shall not exceed one-half the required test period.

(3) If the average gas bill of a customer does not exceed $10 per month over the refund period the monthly consumption of which the refund is calculated may be averaged.

(4) If the recalculated bills indicate that more than $1 is due an existing customer or $2 is due a person no longer a customer of the utility, the full amount of the calculated difference between the amount paid and the recalculated amount shall be refunded to the customer. The refund to an existing customer may be in cash or as credit on a bill. If a refund is due a person no longer a customer of the utility, a notice shall be mailed to the last known address, and the utility shall upon request made within 3 months thereafter refund the amount due.

(5) Whenever a meter is found to be more than 3% slow on any test load, the utility may bill the customer for the amount the test indicates has been undercharged for the period of inaccuracy which period shall not exceed the last 6 months the meter was in service unless otherwise ordered by the commission after investigation. No back billing will be sanctioned if the customer has called to the company's attention his doubts as to the meter's accuracy and the company has failed within a reasonable time to check it.

(6) A classified record shall be kept of the number and amount of refunds and charges made because of inaccurate meters, misapplication of rates, and erroneous billing. A summary of the record for the previous calendar year shall be submitted to the commission by April 1 of each year.

History: Cr. Register, 1-2-56; r. and recr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.15 Employes authorized to enter customers' premises. The utility shall keep a record of employes authorized pursuant to s. 196.171, Stats., to enter customers' premises.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.16 Maps and diagrams. Each utility shall have maps, records, diagrams, and drawings showing the location of its property, in sufficient detail so that the adequacy of service to existing customers may be checked and facilities located.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.17 Complaints. Each utility shall investigate and keep a record of complaints received by it from its customers in regard to safety, service, or rates, and the operation of its system. The record shall show the name and address of the complainant, the date and nature of the complaint, and its disposition and the date thereof. A summary of this record for the previous calendar year shall be sent to the commission by April 1 of each year. Each utility also shall document all contacts and actions relative to deferred payment arrangements and disputes.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59; am. Register, March, 1979, No. 279, eff. 4-1-79.

PSC 134.18 Record of interruption of service. (1) Each utility shall keep a record of all interruptions to service affecting an entire distribution system of any urban area or an important division of a community. The record shall show the date and time of interruption, the cause, the approximate number of customers affected, and the date and time of restoring service.

(2) Each utility shall keep a record of all failures and notifications of difficulty with transmitted gas supply affecting each gate station. The record shall show the date and time of failure or notification, the date and time of resumption of normal supply, the operation of standby equipment including amount of gas produced, the number of customers whose service was interrupted and the maximum and minimum gas supply pressure during the period of difficulty.

(3) A summary of records required by subs. (1) and (2) shall be sent to the public service commission by April 1 of each year.

(4) Each interruption of service which affects more than 100 customers shall be reported by mail, telephone, or telegraph to the commission within 48 hours following the discovery of the interruption.

(5) Any interruption of a principal gas supply shall be immediately reported to the commission by telephone or telegraph by the utility or utilities affected.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.19 Meter records and reports. (1) Whenever a gas meter is tested, such record shall be kept until that meter is tested again. This record shall indicate the information that is necessary for identifying the meter, the reason for making the test, the reading of the meter before it was removed from service, the accuracy of measurement, and all the data that were taken at the time of the test. This record must be sufficiently complete to permit convenient checking of the methods and calculations that have been employed.

(2) Another record shall be kept which indicates when the meter was purchased, its size, its identification, its various places of installation, with dates of installation and removal, the dates and results of all tests, and the dates and details of all repairs. The record shall be arranged in such a way that the record for any meter can be readily located.

(3) All utilities shall keep an "as found" high and light load test summary of all meters tested after being in service. This summary shall be made on a calendar year basis and forwarded to this commission by April 1 of the following year. This summary shall be divided according to the length of time since the last test, and meters found within each of the following per cent accuracy classifications:

(a) Over 115; 110.1-115; 105.1-110; 103.1-105; 102.1-103; 101.1-102; 100.1-101; 100; 99-99.9; 98-98.9; 97-97.9; 95-96.9; 90-94.9; 85-89.9; under 85; passing gas does not register; does not pass gas; not tested; grand total average % error of fast meters; average % error of slow meters; total average error; number tested, number in service.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.20 Preservation of records. The following records shall be preserved and kept available for inspection by the commission for the periods indicated. The list is not to be taken as comprehending all types of utility records.

	Description of Record	Period to be Retained
(1)	Maps showing the location and physical characteristics of existing plants	Currently
(2)	Engineering records in connection with construction projects	Permanently
(3)	Supply records:	
	Station and system supply records	Permanently
	All other records taken in the plant	6 years

Description of Record	Period to be Retained
(4) Operating records:	
Load dispatcher data	6 years
Interruption records	6 years
Meter test	See PSC 134.19
Meter history records	Life of meter
Annual meter accuracy summary	20 years
Heating value records	6 years
Pressure records	6 years
Specific gravity records	6 years
All other records of operation	6 years
(5) Equipment record:	
Must be placed in mortality study before destroying	Life of equipment
(6) Customers' records:	
Inspection of customers' equipment	10 years
Complaint record	6 years
Meter reading sheets or cards	* years
Billing record	* years
Customer deposits	6 years after refund
(7) Filed rates and rules	Permanently

Note: See Federal Power Commission Orders 54 and 156 for preservation of records, Public Service Commission's Classification of Accounts, and section 18.01, Wis. Stats.

* Where machine billing is used and meter readings recorded on tabulating cards, the register sheets may be considered the "meter reading sheets" and the "billing records." "Meter reading sheets" and "billing records" or the "register sheets" shall be kept 6 years or until they are no longer needed to adjust bills. This means that the records must be kept 6 years or from the date of one meter test to the next, whichever is longer.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.21 Heating values and specific gravity. (1) Each utility which is furnishing gas service shall have on file with this commission for each municipality served the heating value, specific gravity, and composition of each type of gas regularly supplied and also for the gas which may be used for standby purposes and the range of values for peak shaving. The heating value filed shall be the total heating value with the indication whether it is on a wet or dry basis. (See definitions in Wis. Adm. Code section PSC 134.02).

(2) All gases whether the regular gas supply, a mixture of gases or a substitute gas used for peak shaving purposes shall operate properly in normal gas utilization equipment. Where used for emergency or standby, the gas shall operate reasonably well in such equipment. (The customer requiring gas of a particular chemical composition shall make such arrangements as may be required to protect against damage by reason of change in composition).

(3) The monthly average heating value of the gases as delivered to the customers in any service area shall not be less than the heating value standard on file with this commission and the heating value at any time at constant specific gravity shall not be more than 5% above or 4% below this standard. At constant heating value, the specific gravity of the gas shall not vary more than 10% from the standards filed with the commission. If the heating value is varied

by a greater amount than specified, the specific gravity shall be varied in such a way that the gas will operate satisfactorily in the customer's utilization equipment. Customers using processes that may be affected by a change in the chemical composition of the gas shall be notified of changes. Agreements with such customers shall specify the allowable variation in composition. (See definitions in Wis. Adm. Code section PSC 134.02).

(4) For required periodic heating value tests see Wis. Adm. Code section PSC 134.25. The specific gravity of the gas shall be determined at least once each month when there is no change in the type or sources of gas and when there is a change in the type of gas. Whenever emergency or peak shaving plants are run or when mixed gases are used, daily determinations of specific gravity shall be made.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.22 Purity of gas. (1) In no case shall gas contain more than 30 grains of sulphur per 100 standard cubic feet, 5 grains of ammonia per 100 standard cubic feet, nor more than 0.1 grain of hydrogen sulphide per 100 standard cubic feet. (Exception. If the gas is not to be placed in pipe or bottle type holders the hydrogen sulphide content may be 0.3 grains per 100 standard cubic feet.)

(2) Utilities supplying gas containing coal or water gas shall make quantitative determinations of total sulphur at least once every 6 months and qualitative hydrogen sulphide tests at intervals of 1 hour to 2 weeks depending upon the probability of this impurity being found.

(3) Utilities supplying liquefied petroleum gas, or liquefied petroleum air mixtures, or natural gas shall test the gas periodically for impurities or periodically obtain data concerning impurities from sources they believe the commission can accept as reliable.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.23 Pressure variation. (1) Every utility supplying gas shall file with the commission a standard service pressure by service areas. The service pressure shall be of such a value that the maximum pressure at any outlet as specified below shall not be greater than 12 inches of water column except for customers utilizing high-pressure service.

(2) For customers receiving standard service pressure, the gas pressure at the outlet of the utility's service meters shall meet the following requirements: (a) At no outlet in the service area shall it ever be greater than one and one-fourth of the standard service pressure nor greater than 12 inches of water nor ever be less than one-half of the standard service pressure nor less than 4 inches of water.

(b) At any single outlet it shall never be greater than twice the actual minimum at the same outlet.

(c) At any one outlet the normal variation of pressure shall not be greater than the following:

Minimum Pressure	Normal Variation Permissible
4–5 in.	3 in.
5–6 in.	3½ in.
6–8 in.	4 in.

(3) For customers utilizing gas at high pressure, a service pressure shall be agreed upon by the utility and the customer, and the maximum pressure variation shall not exceed 15% of the agreed pressure unless the commission shall authorize a greater variation.

(4) No utility shall furnish gas to any customer at pressures higher than its filed standard service pressure until it has filed with the commission acceptable service rules governing high-pressure service to customers desiring to utilize gas at pressures higher than standard service pressure. Such service rules shall provide that the utility will make high-pressure service available to its customers upon request whenever high pressure gas is available at the customer's premises or may be made available in accordance with the utility's filed extension rules, and when such high pressure is required for proper operation of the customer's present or proposed utilization equipment.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59.

PSC 134.24 History: Cr. Register, February, 1959, No. 38, eff. 3-1-59; r. Register, September, 1972, No. 201, eff. 10-1-72.

PSC 134.25 General use of calorimeter equipment. (1) Unless specifically directed otherwise a calorimeter shall be maintained at each gas producing or mixing plant whether the plant is in continuous operation or used only for standby or peak shaving purposes. The calorimeter shall be used to check the operation of the plant and shall measure the heating value of the gas going to the gas lines.

(2) Unless specifically directed otherwise calorimeters shall be maintained in operation in locations where the heating value of the gas can be measured from each different supplier.

(3) Unless specifically directed otherwise a calorimeter shall be maintained and used to measure the heating value of the gas actually sold to customers in those cases where mixed gases are used.

(4) Tests of heating value of the gas shall be made daily whenever gas is supplied at the calorimeter location unless specifically directed otherwise by the commission. The original records of the tests shall be dated, labeled and kept on file for 6 years. A copy of the daily average heating value of gas sold to customers shall be sent the commission each calendar month.

(5) The calorimeter equipment shall be maintained so as to give results within + or — 1%. Recording calorimeters used to test or control the production or mixing of gas or measure the heating value of purchased gas when therm rates are not applicable shall be tested with a gas of known heating value at least 3 times a year or when the accuracy is in question. Recording calorimeters used only with standby or peak shaving production plants shall be tested with a gas of known heating value at least 2 times a yer. Non-recording calorimeter equipment such as the Junkers shall be tested with a gas of known heating value at least once a year or tested against another calorimeter of known accuracy at least once a year.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59; am. (5), Register, January, 1965, No. 109, eff. 2-1-65.

PSC 134.251 Use of recording calorimeter for therm billing. (1) In the application of gas rates based on the therm, a recording calorimeter shall be used to determine the heating value of the gas being distributed to utility customers. These calorimeters will be located as set forth in Wis. Adm. Code section PSC 134.25 (2) and (3). They shall have such accuracy characteristics as to be able to measure the heating value of the gas to within + or — 2 B.t.u., shall be able to reproduce these readings to within + or — 2 B.t.u., and shall be able to hold their accuracy over an extended period of time. The instruments shall be installed in accordance with the manufacturer's recommendations.

(2) Each utility selling gas shall file with the commission a complete installation report stating the following information: Location of calorimeter, kind of gas tested, type of scale, uniform or split scale range, date installed, publication number of manufacturer's applicable book of instructions, outline of the building, the location of the calorimeter or calorimeters within the building, the size, length, gas pressure, and general route of the gas sample pipe from the supply main to each calorimeter and location of all secondary equipment necessary for the operation of the recording calorimeter.

(3) (a) Each utility selling gas shall keep a chronological record of dates and results of test and operations performed on the calorimeter to test and maintain accuracy.

(b) Twice every month the following tests shall be made:

1. Two days of each month shall be selected for the performance of an "as found" accuracy test, mechanical tests, adjustments, and an "as left" accuracy test of each recording calorimeter, and thereafter the specified accuracy tests, adjustments, and maintenance work shall be performed on the same days of each month insofar as practicable.

2. In making the accuracy tests on the calorimeter, the utility shall use reference natural gas which has been certified by the Institute of Gas Technology before cleaning parts or making any adjustments to either the tank unit or the recorder mechanism. The change from line gas to the certified gas should be made so as to have a continuous chart recording. The inlet pressure used should be the same for both calibration and subsequent operation.

3. If the "as found" accuracy test is within + or — 3 B.t.u., no adjustment will be required and the instrument may be returned to service. If the "as found" accuracy test is not within + or — 3 B.t.u., maintenance shall be performed to restore the accuracy of the instrument.

(4) In order that adequate information concerning each cylinder of natural gas which is to be used for the semi-monthly check tests be available at all times, the following information shall be entered

on a form or in a log book provided for the purpose and also on a label or tag securely attached to each cylinder in which the gas is stored:

(a) Institute of Gas Technology Cylinder Number.

(b) Institute of Gas Technology Certificate Number.

(c) Date cylinder was certified.

(d) Date cylinder was received by the utility.

(e) Heating value certified by Institute of Gas Technology.

(f) Basis of the heating value in (e) above.

(g) Heating value to be used in the semi-monthly accuracy tests. This heating value will not include any plus or minus values. For example, if the heating value is 1,000 + or — 0.9 B.t.u. per cubic foot, the heating value will be considered as being 1,000 B.t.u. per cubic foot.

(h) Basis of the heating value in (g) above.

(5) The original chart records produced by the recording calorimeters shall be dated, labeled, and kept on file for 6 years. A copy of the daily average heating value of gas and the results of the semi-monthly "as found" and "as left" test shall be sent to the commission each calendar month.

History: Cr. Register, January, 1965, No. 109, eff. 2-1-65.

PSC 134.26 Meter testing and testing equipment. (1) Each public utility giving gas service is responsible for the accuracy of equipment used to measure service to its customers and all gas supplied by the utility shall be metered unless specific exemption is obtained from the public service commission. The utility shall own and maintain the equipment and facilities necessary for accurately testing the various types and sizes of meters used by the utility for the measurement of gas, shall make the tests required by these rules, shall maintain the measuring devices, and maintain their accuracy; unless arrangements are made to have the work done by others who have properly equipped laboratories, are approved by the commission and arrangements are also made to have equipment and procedures checked by the public service commission. A test by the manufacturer of a metering device is not acceptable unless witnessed by a utility representative.

(2) Each public utility giving gas service shall own and maintain, except as provided in subsection (1), an industry-approved meter prover of a capacity of not less than 5 cubic feet. The meter prover shall be complete with all accessories needed for accurate meter testing, shall be suitably located for meter testing, and shall be protected from drafts and excessive temperature changes. The equipment shall be maintained in good condition and correct adjustment and be capable of determining the accuracy of service meters to within one-half of one per cent. When the meter prover is used to test temperature-compensating meters, there shall be present a temperature-indicating device to accurately determine the temperature of the prover to within + or — 1 degree Fahrenheit.

(3) Each public utility giving gas service through turbine or rotary displacement type meters shall (a) own and maintain, except as provided in subsection (1), a flow or volumetric meter of suitable capacity, together with necessary accessories, and it shall maintain such equipment in proper adjustment so that it will be capable of determining the accuracy of turbine or rotary displacement type

meters to within one-half of one percent; or (b) have a record of tests of each turbine or rotary displacement type meter made by an acceptable laboratory or by a manufacturer witnessed by a representative of the utility. The record should show that the test included a check of the recording device.

(4) Each public utility giving gas service through orifice type meters shall own and maintain, except as provided in subsection (1), instruments for checking the diameter of the orifice, a water column for testing the pressure differential recorder, and a mercury column or a dead weight gauge tester for testing the static pressure recorder so that the utility will be capable of determining the accuracy of these orifices and recorders to within one-half of one per cent.

(5) All instruments and equipment used for testing of meters shall be maintained in good condition and correct adjustment and be capable of determining the accuracy of service meters to within one-half of one percent and shall be checked at least once each 3 years against a standard.

(6) A rotary displacement type meter, when used as a standard for testing other service meters, shall be given a differential test every 6 months. An original differential test record of the standard meter shall be established and all future differential test results shall be recorded and compared with the original test record. When the test differential pressure differs from the original test record by more than 25% at approximately 25% of the capacity of the meter, the meter shall be cleaned and/or repaired. All associated electrical equipment shall be tested before each series of tests. Associated pressure and temperature correction equipment shall be tested every 6 months.

(7) A diaphragm-type meter shall not be used as a standard for testing other service meters.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59; am. (2), Register, January, 1965, No. 109, eff. 2-1-65; am. (3) and (5), cr. (6) and (7), Register, April, 1969, No. 160, eff. 5-1-69.

PSC 134.27 Meter accuracies. All meters shall be set as close to 100% accurate as possible. Diaphragm meters shall be considered correct for service if the results of the multiple tests called for agree within 1% and no test shows an error of more than 1% fast or slow. Turbine and rotary displacement type meters shall be considered correct for service when tested at approximately 10% of rated flow with accuracy between 2% slow and 2% fast, and at approximately 100% flow with accuracy between 1% slow and 1% fast and in the case of turbine type meters, have a spin test time equal to or greater than that on file with the commission under Wis. Adm. Code section PSC 134.28 (6). In orifice type meters, the deviations in the diameter of the orifice shall not exceed the following:

PRACTICAL TOLERANCES FOR ORIFICE DIAMETERS

Orifice Size	Tolerance Plus or Minus	Orifice Size	Tolerance Plus or Minus
.2500	.0003″	1.2500	.0014″
.3750	.0005″	1.5000	.0017″
.5000	.0006″	1.7500	.0020″
.6250	.0008″	2.0000 to 5.0000	.0025″
.7500	.0009″	over 5.0000	.0005″ per inch of diameter
.8750	.0010″		
1.0000	.0012″		

In orifice type meters the sharpness of the orifice edge shall be maintained in such a condition that the upstream edge of the orifice shall not appreciably reflect a beam of light when viewed without magnification. No meter which is mechanically defective shall be placed in service or allowed to remain in service after such defect has been discovered. The inlet and outlet of diaphragm type meters shall be capped when not connected in service.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59; am. intro par. Register, November, 1962, No. 83, eff. 12-1-62; am. intro. par. Register, April, 1969, No. 160, eff. 5-1-69.

PSC 134.28 Meter testing. (1) Each meter test of a diaphragm type meter with a capacity of 2,400 cubic feet per hour or less shall consist of one proving at a rate of flow one-fifth or less of the rated capacity of that meter and one proving at a rate of flow at or greater than the rated capacity of the meter. The capacity of the meter for test purposes shall be the capacity at one-half inch water column differential pressure.

(2) Each meter test of a diaphragm type meter having a capacity greater than 2,400 cubic feet per hour shall consist of one proving at a rate of flow one-fifth or less of the rated capacity of that meter and one proving at a rate of flow not less than 2,500 cubic feet per hour, but not less than twice the minimum test flow. The capacity of the meter for test purposes shall be the capacity at one-half inch water column differential pressure.

(3) Rotary meters shall be tested at two loads with the minimum load at 10% of rating by the use of a portable or volumetric meter or other approved proving devices, or be given a differential test. In the latter case an original test record shall be set up immediately after installation; future differential test results shall be recorded and compared with the original test record.

(4) A test of an orifice meter shall consist of tests of the recording gauges, and the removal, inspection and measurement of the orifice.

(5) Temperature-compensated gas displacement meters when tested shall be provéd to a base temperature of 60 degrees Fahrenheit.

(6) Turbine-type meters shall be tested at two loads with the minimum load at 10% of rating by the use of a portable or volumetric meter or other approved proving devices, or be given a turbine blade, rotor and gear assembly spin test, either by manual or velocity rotation. Before a particular type turbine meter can be used, the manufacturer must file with and be accepted by the commission a minimum coasting time which will satisfactorily indicate the operating condition of the internal metering mechanism. For the spin test method a test record shall be set up; and the original and subsequent spin test results shall be recorded and compared with the specified minimum coasting time as filed with the commission for that type meter.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59; am. (3), Register, November, 1962, No. 83, eff. 12-1-62; cr. (5), Register, January, 1965, No. 109, eff. 2-1-65; cr. (6), Register, April, 1969, No. 160, eff. 5-1-69.

PSC 134.29 Installation test. No meter shall be used to meter gas consumption for billing purposes unless it was tested and found correct, as defined in Wis. Adm. Code section PSC 134.27 not longer than

15 months previous to its use. The first test on a meter or a retest after a major overhaul shall include a check of the registering device and linkages.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59; am. Register, April, 1969, No. 160, eff. 5-1-69.

PSC 134.30 Periodic testing and maintenance. Each utility shall test its meters according to the following schedule except as provided in Wis. Adm. Code section PSC 134.26 (1). Where pressure regulators, volume corrective devices, or other measuring devices are used on the service or used in conjunction with the meters, they shall be tested on the same schedule as the meters.

(1) All diaphragm meters that are measuring dry gas and have non-absorptive type diaphragms or were rediaphragmed since the introduction of dry gas shall be due for removal from service, tested, adjusted, repaired if necessary, and retested if reused, every 144 months if the meter capacity is 2,400 cubic feet per hour or less at ½-inch water column and every 48 months if the capacity is greater than 2,400 cubic feet. Meters shall be tested during the calendar year in which said 144th or 48th month falls.

(2) All diaphragm meters that are measuring dry gas that do not have non-absorptive-type diaphragms and have not been rediaphragmed since the introduction of dry gas shall be removed from service, tested, adjusted, re-diaphragmed and retested within 48 months of the introduction of dry gas if the meter capacity is 2,400 cubic feet per hour at ½-inch water column and within 24 months if the capacity is greater than 2,400 cubic feet.

(3) All diaphragm meters that measure other than dry gas shall be removed from service, tested, adjusted, repaired, if necessary, and retested if reused every 96 months if the meter capacity is 2,400 cubic feet per hour or less at ½-inch water column and every 48 months if the capacity is greater than 2,400 cubic feet.

(4) Rotary meters having a capacity of 15,000 cubic feet per hour or less at 4 oz. water column pressure shall be given a differential test at least once every 48 months and once every 24 months if the capacity is greater than 15,000 cubic feet. When the differential differs from the original test record by more than 50%, the meter shall be cleaned and/or repaired.

(5) Orifice meters shall have their differential and static recording gauges tested at least once each month, the diameter and condition of the orifice checked at least once a year. The specific gravity of the gas shall be checked as required in Wis. Adm. Code section PSC 134.21 (4), and any temperature recording devices tested annually.

(6) Turbine meters shall be given an inspection and spin test at least once every 12 months. When the coasting time is equal to or less than the specified minimum coasting time as on file with the commission, the meter shall be cleaned and/or repaired.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59; am. (4), Register, 1962, No. 83, eff. 12-1-62; am. (1), Register, January, 1965, No. 109, eff. 2-1-65; am. (4) and cr. (6), Register, April, 1969, No. 160, eff. 5-1-69.

PSC 134.31 Request and referee tests. (1) Each utility furnishing gas service shall make a test of the accuracy of any gas meter upon request of the customer, provided the customer does not request such test more frequently than once in 6 months. A report giving the results of each request test shall be made to the customer and the complete, original record shall be kept on file in the office of the utility.

(2) Any gas meter may be tested by a commission inspector upon written application of the customer. For such test, a fee shall be forwarded to the commission by the customer with the application. The amount of this fee shall be refunded to the customer by the utility if the meter is found to be more than 3% fast. The amount of the fee that is to be remitted for such tests shall be $2 for each consumption meter that has a rated capacity not exceeding 1,000 cubic feet per hour; for larger consumption meters, demand meters, etc., the test fee shall be the actual expense of the test.

History: Cr. Register, February, 1959, No. 38, eff. 3-1-59.

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192.359 Customer meter installations: operating pressure.
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192.491 Corrosion control records.

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*192.713 Transmission lines: permanent field repair of imperfections and damage.
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*Sections of the Code of Federal Regulations to which additions have been made.

* (Italics) New sections that have been added.

Subpart A—General

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:

(1) Offshore gathering of gas upstream from the outlet flange of each facility on the outer continental shelf where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream; and

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

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

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

192.3 Definitions.

As used in this part—

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

"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.

"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.

"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.

"Maximum actual operating pressure" means the maximum pressure that occurs during normal operations over a period of 1 year.

"Maximum allowable operating pressure" 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.

"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.

"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.

"Secretary" means the secretary of transportation or any person to whom he has delegated authority in the matter concerned.

"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—

(1) Transports gas from a gathering line or storage facility to a distribution center or storage facility;

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

(3) Transports gas within a storage field.

"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) Offshore is Class 1 location. The Class location onshore is determined by applying the criteria set forth in this section: The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Except as provided in paragraphs (d) (2) and (f) of this section, the class location is determined by the buildings in the class location unit. For the purposes of this section, each separate dwelling unit is counted as a separate building intended for human occupancy.

(b) A Class 1 location is any class location unit that has 10 or less buildings intended for human occupancy.

(c) A Class 2 location is any class location unit that has more than 10 but less than 46 buildings intended for human occupancy.

(d) A Class 3 location is—

(1) Any class location unit that has 46 or more buildings intended for human occupancy; or

(2) An area where the pipeline lies within 100 yards of any of the following:

(i) A building that is occupied by 20 or more persons during normal use.

(ii) A small, well-defined outside area that is occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theater, or other place of public assembly.

(e) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

(f) The boundaries of the class locations determined in accordance with paragraphs (a) through (e) of this section may be adjusted as follows:

(1) A Class 4 location ends 220 yards from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 3 location, the Class 3 location ends 220 yards from the nearest building in the cluster.

(3) When a cluster of buildings intended for human occupancy requires a Class 2 location, the Class 2 location ends 220 yards from the nearest building in the cluster.

192.7 Incorporation by reference.

(a) Any documents or parts thereof incorporated by reference in this part are a part of this regulation as though set out in full.

(b) All incorporated documents are available for inspection in the Office of Pipeline Safety, Room 107, 400 Sixth Street SW., Washington, D.C. In addition, the documents are available at the addresses provided 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.

192.9 Gathering lines.

Each gathering line must comply with the requirements of this part applicable to transmission lines.

192.11 Petroleum gas systems.

(a) No operator may transport petroleum gas in a system that serves 10 or more customers, or in a system, any portion of which is located in a public place (such as a highway), unless that system meets the requirements of this part and of NFPA Standards No. 58 and No. 59. In the event of a conflict, the requirements of this part prevail.

(b) Each petroleum gas system covered by paragraph (a) of this section must comply with the following:

(1) Aboveground structures must have open vents near the floor level.

(2) Belowground structures must have forced ventilation that will prevent any accumulation of gas.

(3) Relief valve discharge vents must be located so as to prevent any accumulation of gas at or below ground level.

(4) Special precautions must be taken to provide adequate ventilation where excavations are made to repair an underground system.

(c) For the purpose of this section, petroleum gas means propane, butane, or mixtures of these gases, other than a gas air mixture that is used to supplement supplies in a natural gas distribution system.

192.13 General

(a) No person may operate a segment of pipeline that is readied for service after March 12, 1971, or in the case of an offshore gathering line, after July 31, 1977, unless:

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part in accordance with section 192.14.

(b) No person may operate a segment of pipeline that is replaced, relocated, or otherwise changed after November 12, 1970, or in the case of an offshore gathering line, after July 31, 1977, unless that replacement, relocation, or change has been made in accordance with this part.

(c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

192.14 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 carry out the following requirements:

(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 a satisfactory condition for safe operation.

(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 J of this part to substantiate the maximum allowable operating pressure permitted by Subpart L of this part.

(b) 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.

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.

(b) In this part—

(1) Words importing the singular include the plural;

(2) Words importing the plural include the singular; and

(3) Words importing the masculine gender include the feminine.

192.17 Filing of inspection and maintenance plans.

(a) Except as provided in paragraph (b) of this section, each operator shall file with the secretary not later than February 1, 1971, a plan for inspection and maintenance of each pipeline facility which he owns or operates. In addition, each change to an inspection and maintenance plan must be filed with the secretary within 20 days after the change is made.

(b) The provisions of paragraph (a) of this section do not apply to pipeline facilities—

(1) That are subject to the jurisdiction of a state agency that has submitted a certification or agreement with respect to those facilities under section 5 of the Natural Gas Pipeline Safety Act (49 U.S.C. 1675); and

(2) For which an inspection and maintenance plan is required to be filed with that state agency.

(c) Plans filed with the secretary must be sent to the office of Pipeline Safety, Department of Transportation, Washington, D.C. 20590.

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.

PSC 192.53 (a) Some of the materials conforming to specifications approved for use under this code may not have properties suitable for the lower portion of the temperature band covered by this code. Engineers are cautioned to give attention to the low-temperature properties of the materials used for facilities to be exposed to unusually low ground temperatures or low atmospheric temperatures. Twenty (20) inch steel pipe and larger, with a specified minimum yield strength of 52,000 p.s.i. or higher, shall be tested for fracture toughness in accordance with the applicable section of respective API standard under which it was produced, except for small lot purchases of pipe where testing for fracture toughness is impractical.

(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.

PSC 192.53 (d) When substantial quantities of pipe are acquired certified reports of chemical composition and physical properties shall be obtained; when the quantity of pipe involved is so limited that this requirement would be impractical, a certified statement shall be obtained setting forth the specification under which the pipe was manufactured.

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;

(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 meets the requirements of paragraph II-C of Appendix B to this part;

(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;

(3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of Appendix B to this part; or

(4) It is used in accordance with paragraph (c) of this section.

(c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured in a listed specification must also pass the weldability tests prescribed in paragraph II-B of Appendix B to this part.

(d) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.

(e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Standard 5LX.

PSC 192.55 (f) Pipe manufactured from steel made by the Bessemer process shall not be used.

192.57 Cast iron or ductile iron pipe.

(a) New cast iron or new ductile iron pipe is qualified for use under this part if it has been manufactured in accordance with a listed specification.

(b) Used cast iron or used ductile iron pipe is qualified for use under this part if inspection shows that the pipe is sound and allows the makeup of tight joints and—

(1) It has been removed from an existing pipeline that operated at the same or higher pressure; or

(2) It was manufactured in accordance with a listed specification.

PSC 192.57 (c) Cast iron pipe shall not be used as a permanent part of any piping system constructed under this code except where it is used as a temporary installation or replacement of short sections of existing cast iron pipe because of maintenance or relocation. In those cases where cast iron pipe is used it shall be designed, installed, and operated in accordance with the applicable sections of this code.

192.59 Plastic pipe.

(a) New plastic pipe is qualified for use under this part if—

(1) When the pipe is manufactured, it is manufactured in accordance with the latest listed edition of a listed specification, except that before March 21, 1975, it may be manufactured in accordance with any listed edition of a listed specification; and

(2) It is resistant to chemicals with which contact may be anticipated.

(b) Used plastic pipe is qualified for use under this part if—

(1) When the pipe was manufactured, it was manufactured in accordance with the latest listed edition of a listed specification, except that pipe manufactured before March 21, 1975, need only have met the requirements of any listed edition of a listed specification;

(2) It is resistant to chemicals with which contact may be anticipated;

(3) It has been used only in natural gas service;

(4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and

(5) It is free of visible defects.

(c) For the purpose of paragraphs (a) (1) and (b) (1) of this section, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it—

(1) Meets the strength and design criteria required of pipe included in that listed specification; and

(2) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

PSC 192.59 (c) *Plastic pipe and tubing shall be adequately supported during storage. Thermoplastic pipe, tubing and fittings shall be protected from long term exposure to direct sunlight.*

192.61 Copper pipe.

Copper pipe is qualified for use under this part if it has been manufactured in accordance with a listed specification.

192.63 Marking of materials.

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

(1) The specification or standard to which it was manufactured; or

(2) MSS standard practice, SP-25.

(b) In addition to the requirements in paragraph (a), thermoplastic pipe manufactured in accordance with the 1974a or earlier listed edition of ASTM D2513 must be marked as required by section 9.2 of ASTM D2513 (1975b edition) unless the pipe was manufactured before May 18, 1978, and is installed where operating temperatures are not above 38°C (100°F).

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

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

(e) 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.

(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

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 the 1972 edition of API RP5L1, except that before February 25, 1975, the transportation may be performed in accordance with the 1967 edition of API RP5L1.

(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.

Subpart C—Pipe Design

192.101 Scope.

This subpart prescribes the minimum requirements for the design of pipe.

192.103 General.

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

192.105 Design formula for steel pipe.

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

$$P = \frac{2\,St}{D} \times F \times E \times T$$

P = Design pressure in pounds per square inch gage.

S = Yield strength in pounds per square inch determined in accordance with 192.107.

D = Nominal outside diameter of the pipe in inches.

t = Nominal wall thickness of the pipe in inches. If this is unknown, it is determined in accordance with 192.109. Additional wall thickness required for concurrent external loads in accordance with 192.103 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 cold worked to meet the SMYS is heated, other than by welding, to 600° F. or more, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section.

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 11D 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, but not more than 52,000 p.s.i.

(2) If the pipe is not tensile tested as provided in subparagraph (1) of this paragraph 24,000 p.s.i.

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 gage 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 in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches 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:

Class location	*Design factor (F)*
1	0.72
2	0.60
3	0.50
4	0.40

(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:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
ASTM A 106	Seamless	1.00
ASTM A 134	Electric fusion arc welded	.80
ASTM A 135	Electric resistance welded	1.00
ASTM A 139	Electric fusion welded	.80
ASTM A 155	Electric fusion arc welded	1.00
ASTM A 211	Spiral welded steel pipe	.80
ASTM A 333	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
API 5 L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	.60
	Furnace lap-welded	.80
API 5 LX	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
API 5 LS	Electric resistance welded	1.00
	Submerged arc welded	1.00
Other	Pipe over 4 inches	.80
Other	Pipe 4 inches or less	.60

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:

Gas temperature in degrees Fahrenheit	*Temperature derating factor (T)*
250 or less	1.000
300	0.967
350	0.933
400	0.900
450	0.867

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

192.117 Design of cast iron pipe.

Cast iron pipe must be designed in accordance with ANSI A 21.1 using the following values for S (bursting tensile strength) and R (modulus of rupture) in the design equations:

Specification	Type of pipe	S	R
		psi	psi
ANSI A 21.3	Pit cast	11,000	31,000
ANSI A 21.7	Centrifugal (metal mold)	18,000	40,000
ANSI A 21.9	Centrifugal (sand-lined mold)	18,000	40,000

192.119 Design of ductile iron pipe.

(a) Ductile iron pipe must be designed in accordance with ANSI A21.50 using the following values in the design equations:
s (design hoop stress) = 16,800 p.s.i.
f (design bending stress) = 36,000 p.s.i.

(b) Ductile iron pipe must be grade (60-42-10) and must conform to the requirements of ANSI A21.52.

192.121 Design of plastic pipe.

The design pressure for plastic pipe is determined in accordance with the following formula, subject to the limitations of s. 192.123:

$$P = 2S \frac{t}{(D-t)} \times 0.32$$

P = Design pressure, gage, kPa (psi).
S = For thermoplastic pipe the long-term hydrostatic strength determined in accordance with the listed specification at a temperature equal to 23° C (73° F), 38° C (100° F), 49° C (120° F), or 60° C (140° F); for reinforced thermosetting plastic pipe, 75,800 kPa (11,000 psi).
t = Specified wall thickness, mm (in.).
D = Specified outside diameter, mm (in.).

192.123 Design limitation for plastic pipe.

(a) The design pressure may not exceed 689 kPa (100 p.s.i.g.) 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 minus 29° C (-20° F); or

(2) In the case of thermoplastic pipe, above the temperature at which the long-term hydrostatic strength used in the design formula under s. 192.121 is determined, except that pipe manufactured before May 18, 1978, may be used at temperatures up to 30° C (100° F); or in the case of reinforced thermosetting plastic pipe, above 66° C (150° F).

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

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

Nominal size in inches	*Minimum wall thickness in millimeters (inches)*
2	1.52 (0.060)
3	1.52 (0.060)
4	1.78 (0.070)
6	2.54 (0.100)

192.125 Design of copper pipe.

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

(b) Copper pipe used in service lines must have a minimum wall thickness as specified for type "L" pipe in ASTM B 88.

(c) Copper pipe used in mains and service lines may not be used at pressures in excess of 100 p.s.i.g.

(d) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains per 100 standard cubic feet of gas.

PSC 192.125 (e) Fittings in copper piping. It is recommended that fittings in copper piping and exposed to the soil, such as service tees, pressure control fittings, etc., be made of bronze, copper or brass.

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 with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service.

192.145 Valves.

(a) Each valve must meet the minimum requirements, or the equivalent, of API 6A, API 6D, MSS SP-70, MSS SP-71, or MSS SP-78, except that a valve designed before July 1, 1976, may meet the minimum requirements of MSS SP-52. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those standards.

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

(c) No valve having shell components made of ductile iron may be used at pressures exceeding 80% 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% 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.g.; and

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

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

192.147 Flanges and flange accessories.

(a) *General requirements.* Each flange or flange accessory must meet the minimum requirements of ANSI B16.5, MSS SP-44, or ANSI B16.24, 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.

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.

192.151 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 that 25% 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 1¼-inch tap may be made in a 4-inch 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 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 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 the ASME Boiler and Pressure Vessel Code, except for the following:

(1) Regularly manufactured butt-welding fittings.

(2) Pipe that has been produced and tested under a specification listed in Appendix B to this part.

(3) Partial assemblies such as split rings or collars.

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20% or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i.g., or more, or is more than 3 inches nominal diameter.

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 anchors or supports to—

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(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% 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.

(e) 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.

(f) 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 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 in diameter that is carrying gas under pressure; or

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

PSC 192.163 *(b) All compressor station buildings shall be constructed of non-combustible materials as defined by the Wisconsin state building code administered by the department of industry, labor and human relations.*

(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.

PSC 192.163 *(c) Exits shall be provided in compliance with the requirements of the Wisconsin state building code administered by* *the department of industry, labor and human relations. Ladders shall not be used for exits.*

(d) *Fenced areas.* Each fence around a compressor station must have at least 2 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 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 Standard C1, so far as that code is applicable.

PSC 192.163 *(e) All electrical equipment and wiring installed in gas transmission and distribution compressor stations shall conform to the requirements of the Wisconsin state electrical code.*

192.165 Compressor stations: liquid removal.

(a) Where entrained vapors in gas may liquefy 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 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

(ii) Electrical circuits needed to protect equipment from damage may remain energized.

(4) It must be operable from at least 2 locations, each of which is—

(i) Outside the gas area of the station;

(ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and

(iii) Not more than 500 feet from the limits of the station.

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

(c) On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

(1) In the case of an unattended compressor station—

(i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or

(ii) When an uncontrolled fire occurs on the platform; and

(2) In the case of compressor station in a building—

(i) When an uncontrolled fire occurs in the building; or

(ii) When the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition.

For the purpose of paragraph (c) (2) (ii) of this section an electrical facility which conforms to Class 1, Group D of the National Electrical Code is not a source of ignition.

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%.

(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.

PSC 192.171 (a) Fire protection. *Fire-protection facilities shall be provided as specifically directed by the department of industry, labor and human relations and the local fire department. The operation of fire-protection facilities, such as pumps, shall not be affected by an emergency shutdown.*

(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.

PSC 192.173 *There shall be compliance with the department of industry, labor and human relations' heating, ventilation, and air conditioning code.*

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:

$$\frac{C=3D\times P\times F}{1{,}000}$$

in which:

C=Minimum clearance between pipe containers or bottles in inches.

D=Outside diameter of pipe containers or bottles in inches.

P=Maximum allowable operating pressure, p.s.i.g.

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 storage site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum allowable operating pressure	*Minimum clearance (feet)*
Less than 1,000 p.s.i.g.	25

1,000 p.s.i.g. or more ------------------------------- 100

(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 either API Standard 5A or ASTM A 372.

(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% 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:

(1) Each point on the pipeline in a Class 4 location must be within 2½ miles of a valve.

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

(3) Each point on the pipeline in a Class 2 location must be within 7½ miles of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles 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 of gas to an offshore platform in an emergency.

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.

PSC 192.181 *(b) It is intended that the distance between the valve and the regulator or regulators shall be sufficient to permit the operation of the valve during an emergency such as a large gas leak or a fire in the station. These valves shall be in accessible locations not closer than 25 feet and preferably not more than 1,500 feet distant from each regulator 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 inches, 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.

PSC 192.183 *(d) In the design of vaults and pits for pressure limiting, pressure relieving and pressure regulating equipment, consideration shall be given to the protection of the installed equipment from damage, such as that resulting from an explosion within the vault or pit, which may cause portions of the roof or cover to fall into the vault.*

PSC 192.183 *(e) Vault or pit openings shall be located so as to minimize the hazards of tools or other objects falling upon the regulator, piping, or other equipment. The control piping and the operating parts of the equipment installed shall not be located under* *a vault or pit opening where workmen can step on them when entering or leaving*

the vault or pit, unless such parts are suitably protected. Whenever a vault or pit opening is to be located above equipment which could be damaged by a falling cover, a circular cover should be installed or other suitable precautions taken.

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—

(1) The vault or pit must be ventilated with 2 ducts, each having at least the ventilating effect of a pipe 4 inches 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.

PSC 192.187 (a) (3) The outside end of the ducts shall be equipped with a suitable weatherproof fitting or vent-head designed to prevent foreign matter from entering or obstructing the duct. The effective area of the openings in such fittings or vent-heads shall be at least equal to the cross-sectional area of a 4-inch duct. The horizontal section of the ducts shall be as short as practical and shall be pitched to prevent the accumulation of liquids in the line. The number of bends and offsets shall be reduced to a minimum and provisions shall be incorporated to facilitate the periodic cleaning of the ducts.

(b) When the internal volume is more than 75 cubic feet but less than 200 cubic feet—

(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 vented, 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 and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

192.189 Vaults: drainage and waterproofing.

(a) Each vault must be designed so as to minimize the entrance of water.

PSC 192.189 (a) *Nevertheless, vault equipment shall always be designed to operate safely, if submerged.*

(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

(c) All electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, ANSI Standard C1.

PSC 192.189 (c) *Electrical equipment in vaults shall conform to the applicable requirements of the Wisconsin state electrical code.*

192.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517.

(b) The design pressure of Acrylonitrile–butadiene–styrene (ABS) and polyvinyl chloride (PVC) Schedule 40 and 80 thermoplastic fittings must be obtained from the following table:

DESIGN PRESSURE OF THERMOPLASTIC FITTINGS. P.S.I.G. OF VARIOUS STRENGTHS, MATERIALS AND CLASS LOCATIONS

		ABS Type I and PVC Type II class location			PVC Type I class location		
Size inches	Schedule	1	2 and 3	4	1	2 and 3	4
½	40	100	100	100	100	100	100
	80	100	100	100	100	100	100
¾	40	100	100	96	100	100	100
	80	100	100	100	100	100	100
1	40	100	100	90	100	100	100
	80	100	100	100	100	100	100
1¼	40	100	92	74	100	100	100
	80	100	100	100	100	100	100
1½	40	100	83	66	100	100	100
	80	100	100	94	100	100	100
2	40	89	69	55	100	100	100
	80	100	100	81	100	100	100
2½	40	99	76	61	100	100	100
	80	100	100	85	100	100	100
3	40	84	66	53	100	100	100
	80	100	94	75	100	100	100
3½	40	77	60	48	100	100	96
	80	100	86	69	100	100	100
4	40	71	56	44	100	100	89
	80	100	81	65	100	100	100
5	40	62	49	39	100	97	78
	80	93	72	58	100	100	100
6	40	56	44	35	100	88	71
	80	89	70	56	100	100	100

NOTE: These pressure ratings are the same value as the design pressure of the corresponding pipe size and schedule in the same class location, as determined by the formula given in 192.121 and the limitations in 192.123 of this part.

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.

PSC 192.195 (3) Suitable types of protective devices to prevent overpressuring of high-pressure distribution systems include:

(i) Spring-loaded relief valves of types meeting the provisions of the ASME Unfired Pressure Vessel Code.

(ii) Pilot-loaded back-pressure regulators used as relief valves, so designed that failure of the pilot system or control lines will cause the regulator to open.

(iii) Weight-loaded relief valves.

(iv) A monitoring regulator installed in series with the primary pressure regulator.

(v) A series regulator installed upstream from the primary regulator, and set to continuously limit the pressure on the inlet of the primary regulator in accordance with the provisions of section 192.201.

(vi) An automatic shut-off device installed in series with the primary pressure regulator, and set to shut off in accordance with the provisions of 192.201. This device must remain closed until manually reset. It should not be used where it might cause an interruption in service to a large number of customers.

(vii) Spring-loaded diaphragm-type relief valves.

PSC 192.195 (4) Suitable types of protective devices to prevent overpressuring of low-pressure distribution systems include:

(i) A liquid seal relief device that can be set to open accurately and consistently at the desired pressure.

(ii) Weight loaded relief valves.

(iii) An automatic shut-off device as described in PSC 192.195 (3) (vi).

(iv) A pilot loaded back-pressure regulator as described in PSC 192.195 (3) (ii).

(v) A monitoring regulator as described in PSC 192.195 (3) (iv).

(vi) A series regulator as described in PSC 192.195 (3) (v).

PSC 192.195 (c) Suitable types of protective devices to prevent overpressuring of gas pressure holders, pipelines and other facilities that might at times be bottle tight include:

(1) Spring-loaded relief valves of types meeting the provisions of the ASME Unfired Pressure Vessel Code.

(2) Pilot-loaded back-pressure regulators used as relief valves, so designed that failure of the pilot system or control lines will cause the regulator to open.

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.g. 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 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.

(6) 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.g., 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 service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) If the maximum actual operating pressure of the distribution systems exceeds 60 p.s.i.g. one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

(1) A service regulator having the characteristics listed in paragraph (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i.g. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 p.s.i.g. or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i.g. or less), and remains closed until manually reset.

(2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

(3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where

the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i.g. For higher inlet pressures, the methods in subparagraph (1) or (2) of this paragraph must be used.

(4) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

PSC 192.197 (d) The service regulator must be of a type that is capable under normal operating conditions of regulating the downstream pressure within the limits of section PSC 134.23 and of limiting the build-up of pressure under no-flow conditions to 50% or less of the discharge pressure maintained under flow conditions.

PSC 192.197 (e) In addition to the provisions of 192.197 (a) and (b) if the maximum actual operating pressure of the distribution system is greater than low pressure and is equal to or less than 60 p.s.i.g., a suitable protective device shall be installed to prevent unsafe overpressuring of the customers' appliances should the service regulator fail. Some of the suitable types of protective devices to prevent overpressuring of customers' appliances are:

(a) A monitoring regulator

(b) A relief valve

(c) An automatic shut-off device

These devices may be installed as an integral part of the service regulator or as a separate unit.

PSC 192.197 (f) Breather vents shall be provided on all service regulators.

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;

PSC 192.199 (e) In addition the outlet ports must be insect-proof and consideration should be given to all exposures in the immediate vicinity including windows or locations where gas can enter confined areas.

(f) Be designed and installed so that the size of the openings, pipes, 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.

PSC 192.199 (h) *Acceptable methods for complying with 192.199 (h) are:*

(i) Lock the stop valve in the open position. Instruct authorized personnel of the importance of not inadvertently leaving the stop valve closed and of being present during the entire period that the stop valve is closed so that they can lock it in the open position before they leave the location.

(ii) Install duplicate relief valves, each having adequate capacity by itself to protect the system and arrange the isolating valves or 3-way valve so that mechanically it is possible to render only one safety device inoperative at a time.

PSC 192.199 (i) *Precautions shall be taken to prevent unauthorized operation of any valve which will make pressure limiting devices inoperative. This provision applies to isolating valves, by-pass valves, and valves on control or float lines which are located between the pressure limiting device and the system which the device protects. A method similar to PSC 192.199 (h) shall be considered acceptable in complying with this provision.*

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.g. 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.g. or more, but less than 60 p.s.i.g. the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i.g.; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i.g., 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) 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.

(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 and the overpressure protective device inoperative.

PSC 192.204 Pipelines on private right-of-way of electric transmission lines.

Where gas pipelines parallel overhead electric transmission lines on the same right-of-way, the company operating the pipelines shall take the following precautions:

(a) Employ blow-down connections that will direct the gas away from the electric conductors.

(b) Install a bonding conductor across points where the main is to be separated and maintain this connection while the pipeline is separated. The current carrying capacity of the bonding conductor should be at least one-half of the capacity of the overhead line conductors.

(c) Make a study in collaboration with the electric company on the common problems of corrosion and electrolysis, taking the following factors into consideration:

(1) The possibility of the pipeline carrying either unbalanced line currents or fault currents.

(2) The possibility of lightning or fault currents inducing voltages sufficient to puncture pipe coatings or pipe.

(3) Cathodic protection of the pipeline, including location of ground beds, especially if the electric line is carried on steel towers.

(4) Bonding connections between the pipeline and either the steel tower footings or the buried ground facilities or the ground-wire of the overhead electric system.

(d) Investigate the necessity of protecting insulating joints in the pipeline against induced voltages or currents resulting from lightning strokes. Such protection can be obtained by connecting buried sacrificial anodes to the pipe near the insulating joints or by bridging the pipeline insulator with a spark-gap or by other effective means.

Subpart E—Welding of Steel in Pipelines

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.

192.223 General.

(a) Welding must be performed in accordance with established written welding procedures that have been qualified under 192.225 to produce sound, ductile welds.

(b) Welding must be performed by welders who are qualified under 192.227 and 192.229 for the welding procedures to be used.

PSC 192.223 (c) *Prior to welding in or around a structure or area containing gas facilities, a thorough check shall be made to determine the possible presence of a combustible gas mixture. Welding shall begin only when safe conditions are indicated.*

192.225 Qualifications of welding procedures.

(a) Each welding procedure must be qualified under section IX of the 1974 edition of the ASME Boiler and Pressure Vessel Code or section 2 of the 1973 edition of API Standard 1104, whichever is appropriate to the function of the weld, except that a welding procedure qualified under section IX of the 1963 edition of the ASME Boiler and Pressure Vessel Code before July 1, 1976, or section 2 of the 1968 edition of API Standard 1104 before March 20, 1975, may continue to be used but may not be requalified under that edition.

(b) When a welding procedure is being qualified under section IX of the ASME Boiler and Pressure Vessel Code, the following steels are considered to fall within the P-Number 1 grouping for the purpose of the essential variable and do not require separate qualification of welding procedures:

(1) Carbon steels that have a carbon content of 0.32 (ladle analysis) or less.

(2) Carbon steels that have a carbon equivalent (C+¼ Mn) of 0.65 percent (ladle analysis) or less.

(3) Alloy steels with weldability characteristics that have been shown to be similar to the carbon steels listed in subparagraphs (1) and (2) of this paragraph.
Alloy steels and carbon steels that are not covered by subparagraph (1), (2), or (3) of this paragraph require separate qualification of procedures for each individual pipe specification in accordance with sections VIII and IX of the ASME Boiler and Pressure Vessel Code.

(c) Each welding procedure must be recorded in detail during the qualifying tests. This record must be retained and followed whenever the procedure is used.

192.227 Qualification of welders.

(a) Except as provided in paragraph (c) of this section, each welder must be qualified in accordance with one of the following:

(1) Section IX of the 1974 edition of the ASME Boiler and Pressure Vessel Code or, if qualified before July 1, 1976, the 1968 edition, except that a welder may not requalify under the 1968 edition.

(2) The following editions of Section 3 of API Standard 1104:

(i) The 1973 edition, except, that a welder may be qualified by radiography under subsection 3.51 without regard for the standards in subsection 6.9 for depth of undercutting adjacent to the root bead unless that depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld, or

(ii) If a welder is qualified before March 20, 1975, the 1968 edition, except that a welder may not requalify under the 1968 edition.

(b) When a welder is being qualified under section IX of the ASME Boiler and Pressure Vessel Code, the following steels are considered to fall within the P-Number 1 grouping for the purpose of the essential variables and do not require separate qualification:

(1) Carbon steels that have a carbon content of 0.32 percent (ladle analysis) or less.

(2) Carbon steels that have a carbon equivalent (C+¼ Mn) of 0.65 percent (ladle analysis) or less.

(3) Alloy steels with weldability characteristics that have been shown to be similar to the carbon steels listed in subparagraphs (1) and (2) of this paragraph.
Alloy steels and carbon steels that are not covered by subparagraph (1), (2), or (3) of this paragraph require separate qualification of welders for each individual pipe specification in accordance with sections VIII and IX of the ASME Boiler and Pressure Vessel Code.

(c) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20% of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C to this part. A welder who makes welded service line connections to mains must also perform an acceptable test weld under section II of Appendix C to this part as a part of his qualifying test. After initial qualification, a welder may not perform welding unless—

(1) Within the preceding 12 calendar months, he has requalified; or

(2) Within the preceding 6 calendar months he 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 or smaller in diameter, two sample welds tested and found acceptable in accordance with the test in section III of Appendix C to this part.

192.229 Limitations on welders.

(a) No welder whose qualification is based on nondestructive testing may weld compressor station pipe and components.

(b) No welder may weld with a particular welding process unless, within the preceding 6 calendar months, he has engaged in welding with that process.

(c) A welder qualified under section 192.227 (a) may not weld unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under—

(1) Section 3 or 6 of the 1973 edition of API Standard 1104, except for the standards in subsection 6.9 for depth of undercutting adjacent to the root bead unless that depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld; or

(2) In the case of tests conducted before March 20, 1975, section 3 or 6 of the 1968 edition of API Standard 1104.

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% 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%, but more than 10%, of SMYS may not deflect the pipe more than 12½° 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% 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.

192.237 Preheating.

(a) Carbon steel that has a carbon content in excess of 0.32 percent (ladle analysis) or a carbon equivalent (C+¼ Mn) in excess of 0.65 percent (ladle analysis) must be preheated for welding.

(b) Carbon steel that has a lower carbon content or carbon equivalent than the steels covered by paragraph (a) of this section must be preheated for welding when reheating will alleviate existing conditions that would limit the welding technique or tend to adversely affect the quality of the weld.

(c) When steel materials with different preheat temperatures are being preheated for welding, the higher temperature must be used.

(d) Preheat temperature must be monitored to ensure that the required preheat temperature is reached before, and maintained during, the welding operation.

192.239 Stress relieving.

(a) Except as provided in paragraph (f) of this section, each weld on carbon steel that has a carbon content in excess of 0.32 percent (ladle analysis) or a carbon equivalent (C+¼ Mn) in excess of 0.65 percent (ladle analysis) must be stress relieved as prescribed in section VIII of the ASME Boiler and Pressure Vessel Code.

(b) Except as provided in paragraph (f) of this section, each weld on carbon steel that has a carbon content of less than 0.32 percent (ladle analysis) or a carbon equivalent (C+¼ Mn) of less than 0.65 percent (ladle analysis) must be thermally stress relieved when conditions exist which cool the weld at a rate detrimental to the quality of the weld.

(c) Except as provided in paragraph (f) of this section, each weld on carbon steel pipe with a wall thickness of more than 1¼ inches must be stress relieved.

(d) When a weld connects pipe or components that are of different thickness, the wall thickness to be used in determining whether stress relieving is required under this section is—

(1) In the case of pipe connections, the thicker of the two pipes joined; or

(2) In the case of branch connections, slip-on flanges, or socket weld fittings, the thickness of the pipe run or header.

(e) Each weld of different materials must be stress relieved, if either material requires stress relieving under this section.

(f) Notwithstanding paragraphs (a), (b), and (c) of this section, stress relieving is not required for the following:

(1) A fillet or groove weld one-half inch, or less, in size (leg) that attaches a connection 2 inches, or less, in diameter; or

(2) A fillet or groove weld three-eighths inch, or less, in groove size that attaches a supporting member or other nonpressure attachment.

(g) Stress relieving required by this section must be performed at a temperature of at least 1,100° F. for carbon steels and at least 1,200° F. for ferritic alloy steels. When stress relieving a weld between steel materials with the different stress relieving temperatures, the higher temperature must be used.

(h) When stress relieving, the temperature must be monitored to ensure that a uniform temperature is maintained and that the proper stress relieving cycle is accomplished.

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 192.243, 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; or

(2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40% 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 the 1973 edition of API Standard 1104. However, the standards in subsection 6.9 for depth of undercutting adjacent to the root bead apply only if—

(1) That depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld; and

(2) Visual determination of internal undercutting is made in all pipe of the same diameter in a pipeline, except where impractical at tie-in welds.

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%.

(2) In Class 2 locations, at least 15%.

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, and offshore, 100% if practicable, but not less than 90%.

(4) Within railroad or public highway rights-of-way, including tunnels, bridges and overhead road crossings, and at pipeline tie-ins, 100%.

PSC 192.243 *(d) (5) In addition, all welds within 500 feet of buildings intended for human occupancy shall be tested.*

PSC 192.243 *(d) (6) If one weld in any random sample is found to be unacceptable then the minimum percentage of welds selected for examination will be that of the next higher class location. If a second weld is found to be unacceptable or if 2 or more welds are found to be unacceptable in the original random sample, then 100% of the welds shall be inspected if practicable, but in no case less than 90% of the welds in that day's construction.*

(e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under 192.241 (b).

(f) When nondestructive testing is required under 192.241 (b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number of nondestructively tested, the number of rejected, and the disposition of the rejects.

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 pipelay vessel, a weld must be removed if it has a crack that is more than 2 inches long or that penetrates either the root or second bead.

(b) Each weld that is repaired must have the defect removed down to clean metal and the segment to be repaired must be preheated. After repair, the segment of the weld that was repaired must be inspected to insure its acceptability. If the repair is not acceptable, the weld must be removed, except that additional repairs made in accordance with written welding procedures qualified under 192.225 are permitted for welds on an offshore pipeline being installed from a pipelay vessel.

PSC 192.246 Precautions to avoid explosions of gas-air mixtures or uncontrolled fires during construction operations.

(a) Operations such as gas or electric welding and cutting with cutting torches can be safely performed on pipelines and mains and auxiliary equipment, provided that they are completely full of gas, or air that is free from combustible material. Steps shall be taken to prevent a mixture of gas and air at all points where such operations are to be performed.

(b) When a pipeline or main can be kept full of gas during a welding or cutting operation, the following procedures are recommended:

(1) Keep a slight flow of gas moving toward the point where cutting or welding is being done.

(2) The gas pressure at the site of the work shall be controlled by suitable means.

(3) Close all slots or open ends immediately after they are cut with tape, and/or tightly fitting canvas or other suitable material.

(4) Do not permit two openings to remain uncovered at the same time. This is doubly important if the two openings are at different elevations.

(c) No welding or acetylene cutting shall be done on a pipeline, main, or auxiliary apparatus that contains air if it is connected to a source of gas, unless a suitable means has been provided to prevent the leakage of gas into the pipeline or mains.

(d) In situations where welding or cutting must be done on facilities which are filled with air and connected to a source of gas and the precautions recommended above cannot be taken, one or more of the following precautions, depending upon the circumstances at the job are required:

(1) Purging of the pipe or equipment upon which welding or cutting is to be done, with combustible gas or inert gas.

(2) Testing of the atmosphere in the vicinity of the zone to be heated before the work is started and at intervals as the work progresses, with a combustible gas indicator or by other suitable means.

(3) Careful verification before the work starts that the valves that isolate the work from a source of gas do not leak.

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.

(e) Each flange on a flanged joint in cast iron pipe must conform in dimensions and drilling to ANSI Standard B16.1 and be cast integrally with the pipe, valve, or fitting.

192.277 Ductile iron pipe.

(a) Each mechanical joint in ductile iron pipe must conform to ANSI Standard A21.52 and ANSI Standard A21.11.

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

(c) 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 standard wall pipe, as defined in ANSI Standard B36.10.

PSC 192.279

Copper pipe shall be joined by using either a compression type coupling or a brazed or soldered lap joint. The filler material used for brazing shall be a copper-phosphorous alloy or silver base alloy. Butt welds are not permissible for joining copper pipe or tubing.

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 Specification D 2513.

(3) The safety requirements of Appendix A of ASTM Specification D 2513 must be met.

(4) The joint may not be heated to accelerate the setting of the cement.

PSC 192.281 (b) (5) *Proper fit between the pipe or tubing and mating socket or sleeve is essential to a good joint. Sound joints cannot normally be made between loose fitting parts.*

PSC 192.281 (b) (6) *A uniform coating of the solvent cement is required on both mating surfaces. After the joint is made, excess cement shall be removed from the outside of the joint. The joint shall not be disturbed until it has properly set.*

PSC 192.281 (b) (7) *This type joint shall not be made between different kinds of plastics.*

(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) Heat may not be applied with a torch or other open flame.

PSC 192.281 (c) (4) *Care must be used in the heating operation to prevent damage to the plastic material from overheating or having the material not sufficiently heated to assure a sound joint.*

PSC 192.281 (c) (5) *This type joint shall not be made between different kinds of plastics.*

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

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

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

PSC 192.281 (d) (3) *An adhesive bonded joint may be heated in accordance with the pipe manufacturer's recommendation in order to accelerate cure.*

PSC 192.281 (d) (4) *Provision shall be made to clamp or otherwise prevent the joined materials from moving until the adhesive is properly set.*

(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.

PSC 192.281 (e) (2) *The tubular stiffener should be flush with end of pipe or tubing and project at least 1/2 in. beyond the outside end of the compression fitting when installed. The stiffener shall be free of rough or sharp edges and shall not be a force fit in the plastic.*

192.283 Plastic pipe; qualifying joining procedures. (a) *Heat Fusion, Solvent Cement and Adhesive Joints.* Before any written procedure established under ss. 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:

(a) The burst test requirements of —

(i) In the case of thermoplastic pipe, paragraph 8.6 (Sustained Pressure Test) or paragraph 8.7 (Minimum Hydrostatic Burst Pressure) of ASTM D2513; or

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

(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 nonlateral pipe connections, follow the tensile test requirements of ASTM D638, except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical Joints.* Before any written procedure established under ss. 192.273 (b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D638-77a (except for conditioning).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 5.0 mm (0.20 in.) per minute, plus or minus 2.5 percent.

(4) Pipe specimens less than 102 mm (4 in.) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 102 mm (4 in.) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 55.6° C. (100° F.) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results, or the manufacturer's rating, whichever is lower, must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980 may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

192.285 Plastic pipe; qualifing persons to make joints. (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 ss. 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 areas; 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 ss. 192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section.

192.287 Plastic pipe; inspection of joints. No person may carry out the inspection of joints in plastic pipes required by ss. 192.273 (c) and 192.185 (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.

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.

PSC 192.307 Detection of gouges and grooves. *The field inspection provided on each job shall be suitable to reduce to an acceptable minimum the chances that gouged or grooved pipe will get into the finished transmission line or main. Inspection for this purpose just ahead of the coating operation and during the lowering in and backfill operation is required.*

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 pressures 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%, or more, of SMYS:

(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% or more of SMYS, a dent that has a depth of—

(i) More than one-quarter inch in pipe 12 ¾ inches or less in outer diameter; or

(ii) More than 2% of the nominal pipe diameter in pipe over 12 ¾ inches 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%, 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 pipe must be removed by cutting out the damaged portion as a cylinder.

PSC 192.309 (f) *Due primarily to climate conditions, gouges, grooves, notches, and dents have been found to be an important cause of steel pipe failures and an attempt shall be made to prevent or eliminate harmful defects of this nature. Subsection 192.309 (b) pertains to transmission lines and mains intended to operate at hoop stresses of 20% or 40% or more of the specified minimum yield strength. However, applicable portions of these paragraphs should also be applied to facilities intended to operate below this hoop stress level.*

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) For pipe more than 4 inches in nominal diameter, the difference between the maximum and minimum diameter at a bend must not be more than 2½ percent of the nominal diameter.

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

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

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

(B) The pipe is 12 inches 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 or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch.

(Sec. 3, Pub. L. 90-481, 82 Stat. 721, 49 USC 1672; 40 FR 43901, 49 CFR 1.53).

PSC 192.313 *(a) (5) Smooth bends on pipe 4 inches in size and smaller shall have a difference between the maximum and minimum diameter of not more than 12.5 percent of the nominal diameter.*

(b) Each circumferential weld of steel pipe that is subjected to stress during bending must be nondestructively tested.

(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 or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch.

(d) Each bend, other than a wrinkle bend made in accordance with 192.315, must have a smooth contour and be free of mechanical damage.

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%, 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 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) Each transmission line or main must be protected from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, offshore pipelines must be protected 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% 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.

PSC 192.319 *(a) This includes grading the ditch so that the pipe has a firm, substantially continuous bearing on the bottom of the ditch. When long sections of pipe that have been welded alongside the ditch are lowered in, care shall be exercised so as not to jerk the pipe or impose any strains that may kink or put a permanent bend in the pipe.*

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that—

(1) Provides firm support under the pipe; and

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

(c) All offshore pipe in water at least 12 feet deep but not more than 200 feet 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.

PSC 192.319 *(b) (3) If there are large rocks in the material to be used for backfill, care should be used to prevent damage to the coating or pipe by such means as the use of rock shield material, or by making the initial fill with rock free material to a sufficient depth over the pipe to prevent rock damage.*

PSC 192.319 *(b) (4) Where flooding of the trench is done to consolidate the backfill, care shall be exercised to see that the pipe is not floated from its firm bearing on the trench bottom.*

PSC 192.319 *(c) The provisions of 192.319 (a) shall also apply to mains operating at less than 20% of the SMYS.*

192.321 Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level.

(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 inches, except that pipe with an outside diameter of 0.875 inches or less may have a minimum wall thickness of 0.062 inches.

(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.

PSC 192.321 *(f) The casing pipe shall be reamed and cleaned to the extent necessary to remove any sharp edges, projections, or abrasive material which could damage the plastic during and after insertion. That portion of the plastic piping which spans disturbed earth shall be adequately protected by a bridging piece or other means from crushing or shearing from external loading or settling of backfill. Care shall be taken to prevent the plastic piping from bearing on the end of the casing.*

PSC 192.321 *(g) Care shall be exercised to avoid rough handling of plastic pipe and tubing. It shall not be pushed or pulled over sharp projections, dropped or have other objects dropped upon it. Caution shall be taken to prevent kinking or buckling, and any kinks or buckles which occur shall be removed by cutting out as a cylinder.*

PSC 192.321 *(h) Changes in direction of plastic piping may be made with bends, tees or elbows under the following limitations:*

(1) Plastic pipe and tubing may be deflected to a radius not less than the minimum recommended by the manufacturer for the kind, type, grade, wall thickness and diameter of the particular plastic used.

(2) The bends shall be free of buckles, cracks, or other evidence of damage.

(3) Changes in direction that cannot be made in accordance with PSC 192.321 (h) (1) above shall be made with elbow-type fittings.

(4) Miter bends are not permitted.

(5) Branch connections shall be made only with socket-type tees or other suitable fittings specifically designed for the purpose.

PSC 192.321 *(i) Plastic piping shall be laid on undisturbed or well compacted soil. If plastic piping is to be laid in soils which may damage it, the piping shall be protected by suitable rock free materials before back-filling is completed. Plastic piping shall not be supported by blocking. Well tampered earth or other continuous support shall be used.*

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% 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.

PSC 192.323 *(e) Casing requirements of highway authorities shall be followed; however, construction type shall not be any less than provided by this code.*

192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 inches 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.

PSC192.325 *(b) If the structure is a public building where people assemble or in areas such as playground, assembly ground, or park, wherever possible the clearance shall be at least 100 feet if the main is operated at more than 100 p.s.i. but less than 500 p.s.i. and shall be at least 150 feet if operated at 500 p.s.i. or more. If these clearances cannot be maintained, then the next higher type of construction shall be used except such construction may be pressure-tested the same as the remainder of the line. No distribution main or transmission line shall be installed under buildings.*

(c) In addition to meeting the requirements of paragraph (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in 192.175 (b).

192.327 Cover.

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

Location	Normal Soil	Consolidated rock
	Inches	Inches
Class 1 location	30	18
Class 2, 3, and 4 locations	36	24
Drainage ditches of public roads and railroad crossings	36	24

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches 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 of cover if the law of the State or municipality—

(1) Establishes a minimum cover of less than 24 inches;

(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) All pipe which is installed in a navigable river, stream, or harbor must have a minimum cover of 48 inches in soil or 24 inches in consolidated rock, and all pipe installed in any offshore location under water less than 12 feet deep, as measured from mean low tide, must have a minimum cover of 36 inches in soil or 18 inches in consolidated rock, between the top of the pipe and the natural bottom. However, less than the minimum cover is permitted in accordance with paragraph (c) of this section.

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.

PSC 192.353 *(b) Whenever practical, the meters shall be installed at the same location.*

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

PSC 192.353 *(c) Meters shall not be installed in bedrooms, closets, bathrooms, under combustible stairways or in unventilated or inaccessible places, nor closer than three feet to sources of ignition, including furnaces and water heaters.*

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

PSC 192.355 *(a) (1) Install a check valve or equivalent if:*

(i) The utilization equipment might induce a back-pressure.

(ii) The gas utilization equipment is connected to a source of oxygen or compressed air.

(iii) Liquefied petroleum gas or other supplementary gas is used as standby and might flow back into the meter. A three-way valve installed to admit the standby supply and at the same time shut off the regular supply, can be substituted for a check valve if desired.

(b) *Service regulator vents and relief vents.* The outside terminal of each service regulator vent and relief vent 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.

PSC 192.355 *(b) (3) At locations where service regulators might be submerged during floods, either a special anti-flood type breather vent fitting shall be installed, or the vent line shall be extended above the height of the expected flood waters.*

(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% 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.g.

(c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50% 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 of cover in private property and at least 18 inches 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

(3) Be sealed at the foundation wall to prevent leakage into the building.

(f) *Installation of service lines under buildings.* Where an underground service line is installed under a building—

(1) It must be encased in a gas-tight conduit;

(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

PSC 192.361 *(g) It is recommended that service to one customer and/or one building be supplied through one service and one shut-off valve.*

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.

PSC 192.365 *(b) Whenever gas is supplied to a theatre, church, school, factory or other building where large numbers of persons assemble, an outside valve in such case will be required.*

(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.g. must be constructed of pipe designed for a minimum of 100 p.s.i.g.

PSC 192.371

(a) When coated steel pipe is to be installed as a service line in a bore, care should be exercised to prevent damage to the coating during installation. For all installations to be made by boring, driving or similar methods or in a rocky type soil, the following practices or their equivalents are recommended:

(1) When a service line is to installed by boring or driving and a coated steel pipe is to be used for the service line, the coated pipe should not be used as the bore pipe or drive pipe and left in the ground as part of the service line. It is preferable to make such installations by first making an oversize bore, removing the pipe used for boring and then inserting the coated pipe.

(2) Coated steel pipe preferably should not be inserted through a bore in exceptionally rocky soil where there is a likelihood of damage to the coating resulting from the insertion.

192.373 Service lines: cast iron and ductile iron.

(a) Cast iron or ductile iron pipe less than 6 inches in diameter may not be installed for service lines.

(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

(c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

192.375 Service lines: plastic.

(a) Each plastic service line outside a building must be installed below ground level, except that it may terminate above ground and outside the building, if—

(1) The above ground part of the plastic service line is protected against deterioration and external damage; and

(2) The plastic service line is not used to support external loads.

PSC 192.375 *(a) (3) The above ground portion of the plastic service line is completely enclosed in a rigid metal tube or metal pipe. The metal tube or pipe shall have a minimum wall thickness of 0.035 in., adequate protection against corrosion, and shall extend a minimum of 6 inches below grade.*

(b) Each plastic service line inside a building must be protected against external damage.

192.377 Service lines: copper.

Each copper service line installed within a building must be protected against external damage.

Copper service lines installed within a building may not be concealed.

***PSC 192.377** (a) Ferrous valves and fittings installed on underground copper service lines shall be protected from contact with the soil or insulated from the copper pipe.*

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.

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.

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 the pipeline is readied for service. However, the 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.

Each operator shall establish procedures to implement the requirements of this subpart. These procedures, 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 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 192.46.

(2) It must have a cathodic protection system designed to protect the pipeline in its entirety in accordance with this subpart, installed and placed in operation within one 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, 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 be cathodically protected in accordance with paragraph (a) (2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines if —

(1) For the size fitting to be used, an operator can show by tests, investigation, or experience in the area of application that adequate corrosion control is provided by alloyage;

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting; and

(3) A means is provided for identifying the location of the fitting.

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 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.

PSC 192.457 (d) Notwithstanding the provisions of 192.457 (b) (regarding active corrosion), effectively coated steel distribution pipelines, except for those portions including services and short sections that because of their nature and installation make cathodic protection impractical and uneconomical, must, not later than August 1, 1975, be cathodically protected along the entire area that is effectively coated in accordance with this subpart.

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 is found, remedial action must be taken to the extent required by 192.483 and the applicable paragraphs of 192.485, 192.487, or 192.489.

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 backfiling, 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 subpart. 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 or short sections of protected mains or transmission lines, not in excess of 100 feet, 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 current 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.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

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 measurements 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 0.1 grain of hydrogen sulfide per 100 standard cubic feet 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 of monitoring internal corrosion must be checked two times each calendar year, at intervals but with intervals not exceeding 7½ months.

192.479 Atmospheric corrosion control: general.

(a) *Pipelines installed after July 31, 1971.* Each aboveground pipeline or portion of a pipeline installed after July 31, 1971 that is exposed to the atmosphere must be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph, if the operator can demonstrate by test, investigation, or experience in the area of application, that a corrosive atmosphere does not exist.

(b) *Pipelines installed before August 1, 1971.* Each operator having an aboveground pipeline or portion of a pipeline installed before August 1, 1971 that is exposed to the atmosphere, shall—

(1) Determine the areas of atmospheric corrosion on the pipeline;

(2) If atmospheric corrosion is found, take remedial measures to the extent required by the applicable paragraphs of 192.485, 192.487, or 192.489; and

(3) Clean and either coat or jacket the areas of atmospheric corrosion on the pipeline with a material suitable for the prevention of atmospheric corrosion.

§ 192.481 Atmospheric corrosion control: monitoring.

After meeting the requirements of s. 192.479 (a) and (b), each operator shall, at intervals not exceeding 3 years for onshore pipelines and at least once each calendar year, but with intervals not exceeding 15 months, for offshore pipelines, reevaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion.

192.483 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 with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on the actual remaining wall thickness. However, if the area of general corrosion is small, the corroded pipe may be repaired. 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.

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 maximum allowable operating pressure of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of the 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, other than unrecorded galvanic anodes installed before August 1, 1971, and neighboring structures bonded to the cathodic protection system.

(b) Each of the following records must be retained for as long as the pipeline remains in service:

(1) Each record or map required by paragraph (a) 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 or that a corrosive condition does not exist.

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 to substantiate the proposed 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:

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

(d) Each weld used to tie-in a test segment of pipeline is excepted from the test requirements of this subpart.

192.505 Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.

(a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30% or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125% of maximum operating pressure on that segment of the pipeline within 300 feet of such a building, but in no event may the test section be less than 600 feet unless the length of the newly installed or relocated pipe is less than 600 feet. However, if the buildings are evacuated while the hoop stress exceeds 50% of SMYS, air or inert gas may be used as the test medium.

(b) In a Class 1 or Class 2 location, each compressor station, regulator station, and measuring station, must be tested to at least Class 3 location test requirements.

(c) Except as provided in paragraph (e) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.

(d) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that—

(1) The component was tested to at least the pressure required for the pipeline to which it is being added; or

(2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added.

(e) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

PSC 192.505 *(f) Except in freezing weather or when water is not available, pipelines or mains larger than 6 inches in diameter, installed in class locations 1, 2, or 3, shall be hydrostatically tested in place to at least 90% of the specified minimum yield strength.*

192.507 Test requirements for pipelines to operate at a hoop stress less than 30% of SMYS and above 100 p.s.i.g.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30% of SMYS and above 100 p.s.i.g. 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 segments being tested.

(b) If, during the test, the segment is to be stressed to 20% 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.g.

and the pressure required to produce a hoop stress of 20% of SMYS; or

(2) The line must be walked to check for leaks while the hoop stress is held at approximately 20% 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 at or below 100 p.s.i.g.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at or below 100 p.s.i.g. 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.g. must be tested to at least 10 p.s.i.g. and each main to be operated at or above 1 p.s.i.g. must be tested to at least 90 p.s.i.g.

PSC 192.509 (c) If substantial protective coatings are used that would seal a split seam, the leak test pressure shall be 100 p.s.i.g.

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.g. but not more than 40 p.s.i.g. must be given a leak test at a pressure of not less than 50 p.s.i.g.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i.g. must be tested to at least 90 p.s.i.g., except that each segment of a steel service line stressed to 20% or more of SMYS must be tested in accordance with 192.507 of this subpart.

PSC 192.511 (d) Each segment of a service line (other than plastic) intended to be operated at a pressure between 0 and 1 p.s.i.g. must be given a leak test at a pressure of not less than 50 p.s.i.g.

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% of the maximum operating pressure or 50 p.s.i.g., whichever is greater. However, the maximum test pressure may not be more than 3 times the design pressure of the pipe.

(d) The temperature of thermoplastic material must not be more than 100° F. during the test.

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% 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% 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% 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 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% 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% of the pressure before the uprating; or

(2) 25% 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% 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% 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.g. or 25% 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 2 approximately equal incremental increases.

(d) If records for cast iron or ductile iron pipeline facilities are not complete enough to ascertain compliance with 192.117 or 192.119, as applicable, the following procedures must be followed:

(1) If the original laying conditions cannot be ascertained, the operator shall assume, when applying the design formulas of ANSI A21.1, that cast iron pipe was supported on blocks with tamped backfill and, when applying the design formulas of ANSI A21.50, 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 opera-

tor 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:

Pipe size (inches)	Allowance (inches)		
	Cast iron pipe		
	Pit cast pipe	Centrifugally cast pipe	Ductile iron pipe
3–8	0.075	0.065	0.065
10–12	0.08	0.07	0.07
14–24	0.08	0.08	0.075
30–42	0.09	0.09	0.075
48	0.09	0.09	0.08
54–60	0.09	-----	-----

NOTE.—The nominal wall thickness of the cast iron is the standard thickness listed in table 10 or table 11, as applicable, of ANSI A21.1 nearest the value obtained under this subparagraph. The nominal wall thickness of ductile iron pipe is the standard thickness listed in table 6 of ANSI A21.50 nearest the value obtained under this subparagraph.

(4) For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit case pipe with a bursting tensile strength of 11,000 p.s.i. and a modulus of rupture of 31,000 p.s.i.

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 establish a written operating and maintenance plan meeting the requirements of this part and keep records necessary to administer the plan.

192.605 Essentials of operating and maintenance plan.

Each operator shall include the following in its operating and maintenance plan:

(a) Instructions for employees covering operating and maintenance procedures during normal operations and repairs.

(b) Items required to be included by the provisions of Subpart M of this part.

(c) Specific programs relating to facilities presenting the greatest hazard to public safety either in an emergency or because of extraordinary construction or maintenance requirements.

(d) A program for conversion procedures, if conversion of a low-pressure distribution system to a higher pressure is contemplated.

(e) Provision for periodic inspections to ensure that operating pressures are appropriate for the class location.

192.607 Initial determination of class location and confirmation or establishment of maximum allowable operating pressure.

(a) Before April 15, 1971, each operator shall complete a study to determine for each segment of pipeline with a maximum allowable operating pressure that will produce a hoop stress that is more than 40% of SMYS—

(1) The present class location of all such pipeline in its system; and

(2) Whether the hoop stress corresponding to the maximum allowable operating pressure for each segment of pipeline is commensurate with the present class location.

(b) Each segment of pipeline that has been determined under paragraph (a) of this section to have an established maximum allowable operating pressure producing a hoop stress that is not commensurate with the class location of the segment of pipeline and that is found to be in satisfactory condition, must have the maximum allowable operating pressure confirmed or revised in accordance with 192.611. The confirmation or revision must be completed not later than December 31, 1974.

(c) Each operator required to confirm or revise an established maximum allowable operating pressure under paragraph (b) of this section shall, not later than December 31, 1971, prepare a comprehensive plan, including a schedule, for carrying out the confirmations or revisions. The comprehensive plan must also provide for confirmations or revisions determined to be necessary under 192.609 to the extent that they are caused by changes in class locations taking place before July 1, 1973.

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% 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 operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

(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.

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 as follows:

(a) If the segment involved has been previously tested in place to at least 90% of its SMYS for a period of not less than 8 hours, the maximum allowable operating pressure must be confirmed or reduced so that the corresponding hoop stress will not exceed 72% of SMYS of the pipe in Class 2 locations, 60% of SMYS in Class 3 locations, or 50% of SMYS in Class 4 locations.

(b) If the segment involved has not been previously tested in place as described in paragraph (a) of this section, the maximum allowable operating pressure 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.

(c) If the segment of pipeline involved has not been qualified for operation under paragraph (a) or (b) of this section, it 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 so as to be equal to or less than the following:

(1) 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.

(2) 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.

(3) The corresponding hoop stress may not exceed 72% of the SMYS of the pipe in Class 2 locations, 60% of SMYS in Class 3 locations, or 50% of the SMYS in Class 4 locations.

(d) 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.

(e) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under 192.609 must be completed as follows:

(1) Confirmation or revision due to changes in class location that occur before July 1, 1973, must be completed not later than December 31, 1974.

(2) Confirmation or revision due to changes in class location that occur on or after July 1, 1973, must be completed within 18 months of the change in class location.

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 recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with 192.619 (a) and (b).

PSC 192.613 *(c) When street is paved or repaved. Whenever a road or street is paved or repaved with permanent pavement, the operator shall:*

(1) Check for leaks along all mains and services in the streets and abutting property. The check shall be conducted by testing with a combustible gas indicator air samples taken from holes placed near the pipes. The utility may substitute for bar hole tests a ground surface survey with a continuous-sampling instrument capable of detecting combustible gas in air concentrations of 100 parts per million.

(2) Determine condition of pipe and joints by sample visual examination.

(3) Place clamps on, reconstruct, or repair joints if they are likely to dry out or are leaking.

(4) Replace pipe if existing pipe is corroded to such an extent that it is likely to require replacement before the street is again resurfaced.

PSC 192.613 (d) Underground pipes. Whenever underground pipes are exposed in order to repair leaks, the utility shall record on the repair order the nature of the leak and possible cause from observation.

PSC 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.

(b) Each operator shall—

(1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.

(2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to—

(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

(d) 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.

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.

(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.

PSC 192.619 *(a) (2) (i) For plastic pipe used as a gas service, the maximum allowable operating pressure in any class location shall not exceed 60 p.s.i.g.*

(ii) For steel pipe, operated at 100 p.s.i.g. or more, the test pressure is divided by a factor determined in accordance with the following table:

	Factors*		
Class location	Segment installed before (Nov. 12, 1970)	Segment installed after (Nov. 11, 1970)	Segment converted under 192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

* 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, 1971) 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) For furnace butt welded steel pipe, a pressure equal to 60% of the mill test pressure to which the pipe was subjected.

(5) For steel pipe other than furnace butt welded pipe, a pressure equal to 85% of the highest test pressure to which the pipe has been subjected, whether by mill test or by the post installation test.

(6) 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 pressure.

(b) No person may operate a segment to which paragraph (a) (6) of this section is applicable, 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.

192.621 Maximum allowable operating pressure: high-pressure distribution systems.

(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

(1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part.

(2) Sixty p.s.i.g., for a segment of a distribution system otherwise designed to operate at over 60 p.s.i.g., unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of 192.197 (c).

(3) Twenty-five p.s.i.g. in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

PSC 192.621 *(a) (3) No person may operate a segment of a cast iron pipe in which there are unreinforced bell and spigot joints at a pressure higher than low pressure unless it can be proven to the commission that they can be operated at a higher pressure. However, the maximum allowable operating pressure under any circumstances shall not exceed 15 p.s.i.g.*

(4) The pressure limits to which a joint could be subjected without the possibility of its parting.

(5) 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 overpressure 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.

PSC 192.621 *(c) Sixty p.s.i.g. in individual distribution systems or portions thereof. The intercity or supply mains for these distribution systems may be operated at higher pressures provided by this code if the number of services supplied from these mains are limited and these mains are not an integral part of the distribution system. The pressure and the services supplied from these higher pressure intercity and supply mains shall be limited to 60 p.s.i.g. unless the service lines are equipped with series regulators or other pressure limiting devices as prescribed in 192.197 (c)*

192.623 Maximum and minimum allowable operating pressure: low-pressure distribution systems.

(a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

(b) No person may operate a low pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

PSC 192.623 *(c) No person may operate a low pressure distribution system at a pressure in excess of that provided by section PSC 134.23 (1).*

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 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 of which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction; or

(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.

(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.

(g) The odorization requirements of Part 190 of this chapter, as in effect on August 12, 1970, must be complied with, in each State in which odorization of gas in transmission lines is required by that part, until the earlier of the following dates:

(1) January 1, 1977; or

(2) The date upon which the distribution companies in that State are odorizing gas in accordance with paragraphs (a) through (f) of this section.

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.

PSC 192.629 (c) No pipeline, main, or service shall be purged into any building or confined space.

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:

Class location of line	Maximum intervals between patrols	
	At highway and railroad crossings	At all other places
1, 2	6 months	1 year
3	3 months	6 months
4	do	3 months

192.706 Transmission lines; leakage surveys.

(a) Each operator of a transmission line shall provide for periodic leakage surveys of the line in its operating and maintenance plan.

(b) Leakage surveys of a transmission line must be conducted at intervals not exceeding 1 year. However, in the case of a transmission line which transports gas in conformity with section 192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted—

(1) In Class 3 locations, at intervals not exceeding 6 months; and

(2) In Class 4 locations, at intervals not exceeding 3 months.

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, railroad, and navigable waterway; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

However, until January 1, 1978, paragraphs (a) (l) and (a) (2) of this section do not apply to mains installed before April 21, 1975, and until January 1, 1978, paragraph (a) (l) of this section does not apply to transmission lines installed before April 21, 1975.

(b) *Exceptions for buried pipelines.* Line markers are not required for buried mains and transmission lines—

(1) Located offshore or under inland navigable waters;

(2) In Class 3 or Class 4 locations—

(i) Where placement of a marker is impractical; or

(ii) Where a program for preventing interference with underground pipelines is established by law; or

(3) In the case of navigable waterway crossings, within 100 feet of a line marker placed and maintained at that waterway in accordance with this section.

(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) *Markers other than at navigable waterways.* The following must be written legibly on a background of sharply contrasting color on each line marker not placed at a navigable waterway.

(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 one inch high with one-quarter inch stroke.

(2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

(e) *Markers at navigable waterways.* Each line marker at a navigable waterway must have the following characteristics:

(1) A sign, rectangular in shape, with a narrow strip along each edge colored international orange and the area between lettering on the sign and boundary strips colored white.

(2) Written on the sign in block style, black letters—

(i) The word "Warning," "Caution," or "Danger" followed by the words "Do Not Anchor or Dredge" and the words "Gas (or name of gas transported) Pipeline Crossing"; and

(ii) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

(3) In overcast daylight, the sign is visible and the writing required by paragraph (e) (2) (i) of this section is legible, from approaching or passing vessels that may damage or interfere with the pipeline.

(f) *Existing markers.* Line markers installed before April 21, 1975, which do not comply with paragraph (d) or (e) of this section may be used until January 1, 1980.

PSC 192.707

When transmission lines are located outside urban areas, their location shall be marked (recognizable to the public) at each fence line, road crossing, railroad crossing, river, lake, stream, or drainage ditch crossing and wherever it is considered necessary to identify the location of a pipeline to reduce the possibility of damage or interference.

192.709 Transmission lines: record-keeping. Each operator shall keep records covering each leak discovered, repair made, transmission line break, leakage survey, line patrol, and inspection, for as long as the segment of transmission line involved remains in service.

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% of the 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 (a) (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) Except as provided in paragraph (b) of this section each imperfection or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40% of SMYS must be repaired as follows:

(1) If it is feasible, to take the segment out of service, the imperfection or damage must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

(2) If it is not feasible to take the segment out of service, a full encirclement welded split sleeve of appropriate design must be applied over the imperfection or damage.

(3) If the segment is not taken out of service, the operating pressure must be reduced to a safe level during the repair operations.

PSC 192.713(a) (4) Gouges and grooves of lesser depth than 10% of the nominal wall thickness of the pipe may be removed by grinding out to a smooth contour provided the grinding does not reduce the remaining wall thickness to less than the minimum prescribed by this code for the conditions of use.

(b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the imperfection or damage.

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 is 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% of the SMYS of the pipe; and

(3) Grinding of the defective area can be limited so that at least ⅛-inch 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. (a) Except as provided in paragraph (b) of this section, each permanent field repair of a leak on a transmission line must be made as follows:

(1) If feasible, the segment of transmission line must be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

(2) If it is not feasible to take the segment of transmission line out of service, repairs must be made by installing a full encirclement welded split sleeve of appropriate design, unless the transmission line—

(i) Is joined by mechanical couplings; and

(ii) Operates at less than 40 percent of SMYS.

(3) If the leak is due to a corrosion pit, the repair may be made by installing a properly designed bolt-on-leak clamp; or, if the leak is due to a corrosion pit and on pipe of not more than 40,000 psi SMYS, the repair may be made by fillet welding over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.

(b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the leak.

192.719 Transmission lines: testing of repairs. (a) *Testing of replacement pipe.* (1) 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.

(2) The test required by subparagraph (1) of this paragraph may be made on the pipe before it is installed, but all field girth bolt welds that are not strength tested must be tested after installation by nondestructive tests meeting the requirements of 192.243.

(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.

PSC 192.720 *Repair of steel pipe operating below 40% of the specified minimum yield strength.*

If inspections at any time reveal an injurious defect, gouge, groove, dent, or leak, immediate temporary measures shall be employed to protect the property and public if it is not feasible to make permanent repair at time of discovery. As soon as feasible, permanent repairs shall be made using recognized methods ofrepair.

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 patroled at intervals not exceeding 3 months.

PSC 192.722 Distribution mains: markers. *When distribution mains are located outside urban areas, their location shall be marked (recognizable to the public) at each fence line, road crossing, railroad crossing, river, lake, stream, or drainage ditch crossing and wherever it is considered necessary to identify the location of a pipeline to reduce the possibility of damage or interference.*

192.723 Distribution systems: leakage surveys and procedures. (a) Each operator of a distribution system shall provide for periodic leakage surveys in its operating and maintenance plan.

(b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

(1) A gas detector survey must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 1 year.

(2) Leakage surveys of the distribution system outside of the principal business areas must be made as frequently as necessary, but at intervals not exceeding 5 years.

PSC 192.723 *Every operator shall maintain a gas leak-detection program and shall maintain records of operation under the program. The program shall consist of not less than the following:*

(a) In principal business districts (as shown by maps filed with the public service commission by each utility) a reasonable street-opening survey shall be conducted twice annually by making tests with combustible gas indicators in street openings such as telephone and electric vaults and manholes, catch basins and sewer system manholes, and gas system openings.

(b) In each principal business district a building survey shall be conducted once a year. The piping from the service entrance to the meter outlet and metering and regulating equipment shall be tested for gas leakage in those buildings that have gas service.

(c) A survey of all buildings used for public gatherings such as schools, churches, hospitals, and theaters shall be conducted once each year. The piping from the service entrance to the meter outlet and metering and regulating equipment shall be tested for gas leakage.

(d) In residential areas, in addition to a survey of public buildings the vegetation shall be checked. At least 3 barhole tests shall be made in each block; at least one street opening shall be checked if one exists in each block or at each intersection; and on streets where system is operating at a pressure of more than 10 p.s.i.g., all street openings shall be checked. (See 192.723 (b) (1) above for types of street openings.) The utility may substitute for the barhole tests a ground surface survey with a hand-operated, continuous-sampling instrument capable of detecting combustible gas in air concentrations of 100 parts per million. The utility may substitute for all the tests required by this section

(PSC 192.723 (d)) a survey by mobile flame ionization or infrared gas detection units, provided that a method be included to check individual services. The tests required by this section (PSC 192.723 (d)) shall be made each year.

(e) Along lines in rural areas, the vegetation shall be checked annually.

(f) When a leak complaint is received and the odor of gas indicates that there is a leak in or near the premises, a search shall be carried to conclusion until such leak is found.

PSC 192.724 Further leakage survey after repair of leak. *When a leak is found and repaired, a further check shall be made in the vicinity of the repaired leak to determine if there is any other source of migrant gas in the neighborhood.*

192.725 Test requirements for reinstating service lines. (a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

192.727 Abandonment or inactivation of facilities. (a) Each operator shall provide in its operating and maintenance plan for abandonment or deactivation of pipelines, including provisions for meeting each of 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 off-shore 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 gas supply and the open pipe ends sealed.

(e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.

(f) Each abandoned vault must be filled with a suitable compacted material.

PSC 192.727 *(g) Special efforts shall be made to include services which have not been used for two years in a way that will remove gas from the customers' premises. The plan shall include the following provisions:*

(1) If the facilities are abandoned in place, they shall be physically disconnected from the piping system. The open ends of all abandoned facilities shall be capped, plugged, or otherwise effectively sealed.

(2) In cases where a main is abandoned, together with the service lines connected to it, insofar as service lines are concerned, only the customers' end of such service lines need be sealed as stipulated above.

192.729 Compressor stations: procedures for gas compressor units. Each operator shall establish starting, operating, and shutdown procedures for gas compressor units.

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 to exceed 1 year, to determine that it functions properly.

192.733 Compressor stations: isolation of equipment for maintenance or alterations. Each operator shall establish procedures for maintaining compressor stations, including provisions for isolating units or sections of pipe for purging before returning to service.

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.

PSC 192.735 *(c) All aboveground oil or gasoline storage tanks shall be constructed and protected in accordance with the applicable codes of the department of industry, labor and human relations.*

192.737 Pipe-type and bottle-type holders: plan for inspection and testing. Each operator having a pipe-type or bottle-type holder shall establish a plan for the systematic, routine inspection and testing of these facilities, including the following:

(a) Provision must be made for detecting external corrosion before the strength of the container has been impaired.

(b) Periodic sampling and testing of gas in storage must be made to determine the dew point of vapors contained in the stored gas, that if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant.

(c) The pressure control and pressure limiting equipment must be inspected and tested periodically to determine that it is in a safe operating condition and has adequate capacity.

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 1 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 gages.

(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gages 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 gages in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

(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.

PSC 192.741 *(d) Each low pressure distribution system must be equipped with telemetering or recording pressure gage or gages as may be required to properly indicate the gas pressure in the system at all times. At least once each year the pressure variation shall be determined throughout each system.*

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 1 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 one 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.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.

PSC 192.744 Service regulators and associated safety devices: inspection and testing. *Company service regulators and associated safety devices on customers' premises shall be inspected and tested periodically to determine whether they are in proper operating condition. The above shall include testing of the set pressure of the regulator at a specific flow rate, determination of the lock-up pressure, and determine as to whether there are any leaks, internal or external, associated with the regulator. The test interval shall be the same as the interval between meter changes in the meter rotation program. (See section PSC 134.30.)*

192.745 Valve maintenance: transmission lines. Each transmission line valve that might be required during any emergency must be inspected and partially operated, at intervals not exceeding 1 year.

192.747 Valve maintenance: distribution systems. Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced, at intervals not exceeding 1 year.

PSC 192.747 *(a) Inspection shall include checking of alignment to permit use of a key or wrench and clearing from the valve box or vault any debris which would interfere or delay the operation of the valve. Records shall be maintained to show specific valve location and such records shall be made continuously accessible to authorized personnel for use under emergency conditions.*

(b) Existing connections in the form of inline valves between low pressure gas distribution systems and high pressure gas distribution systems shall be physically severed by January 1, 1974.

(c) The by-pass valves in district regulator stations supplying gas to a low pressure distribution system shall be sealed, locked or otherwise be rendered incapable of operation, except by authorized personnel by January 1, 1974.

192.749 Vault maintenance. (a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet or more, must be inspected, at intervals not exceeding 1 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.

PSC 192.751 *(d) Whenever the accidental ignition in the open air of gas-air mixture might be likely to cause personal injury or property damage, precautions shall be taken as, for example:*

(1) Prohibit smoking and open flames in the area, and

(2) Install a metallic bond around the location of cuts in gas pipes to be made by other means than cutting torches, and

(3) Take precautions to prevent static electricity sparks, and

(4) Provide fire extinguishers of appropriate size and type in accordance with the department of industry, labor and human relations' requirements.

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.g. 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.g. and is exposed for any reason, must be sealed by a means other than caulking.

PSC 192.753 *Existing unreinforced bell and spigot jointed cast iron pipe shall be operated at low pressure unless it can be proved to the commission that they can be satisfactorily operated at a higher pressure. However, the operating pressure under any circumstances shall not exceed 15 p.s.i.g.*

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).

APPENDIX A—INCORPORATED BY REFERENCE

I. List of organizations and addresses.

A. American National Standards Institute (ANSI), 1430 Broadway, New York, N. Y. 10018 (formerly the United States of American Standards Institute (USASI)). All current standards issued by USASI and ASA have been redesignated as American National Standards and continued in effect.

B. American Petroleum Institute (API), 1801 K Street NW, Washington, D.C. 20006, or 300 Corrigan Tower Building, Dallas, Texas, 75201.

C. The American Society of Mechanical Engineers (ASME) United Engineering Center, 345 East 47th Street, New York, N. Y. 10017.

D. American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pa. 19103.

E. Manufacturers Standardization Society of the Valve and Fittings Industry (MSS), 1815 North Fort Myer Drive, Room 913, Arlington, Va. 22209.

F. National Fire Protection Association (NFPA), 470 Atlantic Avenue, Boston, Mass. 02110.

II. Documents incorporated by reference. Numbers in parentheses indicate applicable editions. Only the latest listed edition applies, except that an earlier listed edition may be followed with respect to pipe or components which were manufactured, designed, or installed before the latest edition is adopted, unless otherwise provided in this part.

A. American Petroleum Institute:

(1) API Standard 5A "API Specifications for Casing, Tubing, and Drill Pipe" (1968, 1971, 1973 plus Supp. 1).

(2) API Standard 6A "API Specification for Wellhead Equipment" (1968, 1974).

(3) API Standard 6D "API Specification for Pipeline Valves" (1968, 1974).

(4) API Standard 5L "API Specification for Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

(5) API Standard 5LS "API Specification for Spiral-Weld Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

(6) API Standard 5LX "API Specification for High-Test Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1, and 1977).

(7) API Recommended Practice 5LI "API Recommended Practice for Railroad Transportation of Line Pipe" (1967, 1972).

(8) API Standard 1104 "Standard for Welding Pipe Lines and Related Facilities" (1968, 1973).

B. The American Society for Testing and Materials:

(1) ASTM Specification A53 "Standard Specification for Welded and Seamless Steel Pipe" (A53-65, A53-68, A53-73).

(2) ASTM Specification A72 "Standard Specification for Welded Wrought-Iron Pipe" (A72-64T, A72-68).

(3) ASTM Specification A106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A106-66, A106-68, A106-72a).

(4) ASTM Specification A134 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Plate Pipe, Sizes 16 in. and over" (A134-64, A134-68, A134-73).

(5) ASTM Specification A135 "Standard Specification for Electric-Resistance-Welded Steel Pipe" (A135-63T, A135-68, A135-73a).

(6) ASTM Specification A139 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Pipe (Sizes 4 in. and over)" (A139-64, A139-68, A139-73).

(7) ASTM Specification A155 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service" (A155-65, A155-68, A155-72a).

(8) ASTM Specification A211 "Standard Specification for Spiral-Welded Steel or Iron Pipe" (A211-63, A211-68, A211-73).

(9) ASTM Specification A333 "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (A333-64, A333-67, A333-73).

(10) ASTM Specification A372 "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessel" (A372-67, A372-71).

(11) ASTM Specification A377 "Standard Specifications for Cast Iron and Ductile Iron Pressure Pipe" (A377-66, A377-73).

(12) ASTM Specification A381 "Standard Specification for Metal-Arc-Welded Steel Pipe for High-Pressure Transmission Systems" (A381-66, A381-68, A381-73).

(13) ASTM Specification A539 "Standard Specification for Electric Resistance-Welded Coiled Steel Tubing for Gas and Fuel Oil Lines" (A539-65, A539-73).

(14) ASTM Specification B42 "Standard Specification for Seamless Copper Pipe, Standard Sizes" (B42-62, B42-66, B42-72).

(15) ASTM Specification B68 "Standard Specification for Seamless Copper Tube, Bright Annealed" (B68-65, B68-68, B68-74).

(16) ASTM Specification B75 "Standard Specification for Seamless Copper Tube" (B75-65, B75-68, B75-74).

(17) ASTM Specification B88 "Standard Specification for Seamless Copper Water Tube" (B88-66, B88-72).

(18) ASTM Specification B251 "Standard Specification for General Requirements for Wrought Seamless Copper and Copper-Alloy Tube" (B251-66, B251-68, B251-72).

(19) ASTM Specification D638 "Standard Test Method of Tensile Properties of Plastic" (D638-77a)

(20) ASTM Specification D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (D2513-66T, D2513-68, D2513-70, D2513-71, D2513-73, D2513-74a).

(21) ASTM Specification D2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (D2517-66T, D2517-67, D2517-73).

C. The American National Standards Institute, Inc.:

(1) ANSI A21.1 "Thickness Design of Cast-Iron Pipe" (A21.1-1967, A21.1-1972).

(2) ANSI A21.3 "Specifications for Cast Iron Pit Cast Pipe for Gas" (A21.3-1953).

(3) ANSI A21.7 "Cast-Iron Pipe Centrifugally Cast in Metal Molds for Gas" (A21.7-1962).

(4) ANSI A21.9 "Cast-Iron Pipe Centrifugally Cast in Sand-Lined Molds for Gas" (A21.9-1962).

(5) ANSI A21.11 "Rubber-Gasket Joints for Cast-Iron and Ductile-Iron Pressure Pipe and Fittings" (A21.11-1964, A21.11-1972).

(6) ANSI A21.50 "Thickness Design of Ductile-Iron Pipe" (A21.50-1965, A21.50-1971).

(7) ANSI A21.52 "Ductile-Iron Pipe, Centrifugally Cast, in Metal Molds or Sand-Lined Molds for Gas" (A21.52-1965, A21.52-1971).

(8) ANSI B16.1 "Cast Iron Pipe Flanges and Flanged Fittings" (B16.1-1967).

(9) ANSI B16.5 "Steel Pipe Flanges, Flanged Valves and Fittings (B16.5-1968, B16.5-1973).

(10) ANSI B16.24 "Bronze Flanges and Flanged Fittings" (B16.24-1962, B16.10-1971).

(11) ANSI B36.10 "Wrought Steel and Wrought Iron Pipe" (B36.10-1959, B36.10-1970).

(12) ANSI C1 "National Electrical Code" (C1-1968, C1-1975).

D. The American Society of Mechanical Engineers:

(1) ASME Boiler and Pressure Vessel Code Section VIII "Pressure Vessels, Division 1" (1968, 1974).

(2) ASME Boiler and Pressure Vessel Code, Section IX "Welding Qualifications" (1968, 1974).

E. Manufacturer's Standardization Society of the Valve and Fittings Industry:

(1) MSP-25 "Standard Marking System for Valves, Fittings, Flanges, and Union" (1964).

(2) MSS SP-44 "Steel Pipe Line Flanges" (1955, 1972, 1975).

(3) MSS SP-52 "Cast Iron Pipe Line Valves" (1957).

(4) MSS SP-70 "Cast Iron Gate Valves, Flanged and Threaded Ends" (1970).

(5) MSS Sp-71 "Cast Iron Swing Check Valves, Flanged and Threaded Ends" (1970).

(6) MSS Sp-78 "Cast Iron Plug Valves" (1972).

F. National Fire Protection Association:

(1) NFPA Standard 30 "Flammable and Combustible Liquids Code" (1969, 1973).

(2) NFPA Standard 58 "Standard for the Storage and Handling of Liquefied Petroleum Gases" (1969, 1972).

(3) NFPA Standard 59 "Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants" (1968).

(4) NFPA Standard 59A "Storage and Handling Liquefied Natural Gas" (1971, 1972).

Appendix B—Qualification of Pipe

I. Listed Pipe Specifications. Numbers in parentheses indicate applicable editions. Only the latest listed edition applies, except that an earlier listed edition may be followed with respect to pipe or components which were manufactured, designed, or installed before the latest edition is adopted unless otherwise provided in this part.

API 5L—Steel and iron pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

API 5LS—Steel pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1 and 1977).

API 5LX—Steel pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975 plus Supp. 1 and 1977).

ASTM A53—Steel pipe (1965, 1968, 1973).

ASTM A72—Wrought Iron Pipe (1964T, 1968).

ASTM A106—Steel pipe (1966, 1968, 1972a).

ASTM A134—Steel pipe (1964, 1968, 1973).

ASTM A135—Steel pipe (1963T, 1968, 1973a).

ASTM A139—Steel pipe (1964, 1968, 1973).

ASTM A155—Steel pipe (1965, 1968, 1972a).

ASTM A211—Steel and iron pipe (1963, 1968, 1973).

ASTM A333—Steel pipe (1964, 1967, 1973).

ASTM A377—Cast iron pipe (1966, 1973).

ASTM A381—Steel pipe (1966, 1968, 1973).

ASTM A539—Steel tubing (1965, 1973).

ASTM B42—Copper pipe (1962, 1966, 1972).

ASTM B68—Copper tubing (1965, 1968, 1974).

ASTM B75—Copper tubing (1965, 1968, 1974).

ASTM B88—Copper tubing (1966, 1972).

ASTM B251—Copper pipe and tubing (1966, 1968, 1972).

ASTM D2513—Thermoplastic pipe and tubing (1966T, 1968, 1970, 1971, 1973, 1974a).

ASTM D2517—Thermosetting plastic pipe and tubing (1966T, 1967, 1973).

ANSI A21.3—Cast iron pipe (1953).

ANSI A21.7—Cast iron pipe (1962).

ANSI A21.9—Cast iron pipe (1962).

ANSI A21.52—Ductile iron pipe (1965, 1971).

II. *Steel pipe of unknown or unlisted specification.*

A. *Bending Properties.* For pipe 2 inches 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 in diameter, the pipe must meet the requirements of the flattening test 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 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 in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches or less in diameter, at least one test weld must be made for each 400 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 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.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i.g. or less, or the tensile properties may be established by performing tensile tests as set forth in API Standard 5LX. All test specimens shall be selected at random and the following number of tests must be performed:

Number of Tensile Tests—All Sizes

10 lengths or less—1 set of tests for each length.

11 to 100 lengths—1 set of tests for each 5 lengths, but not less than 10 tests.

Over 100 lengths—1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in 192.55 (c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.* Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *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 that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for ac-

ceptance 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.

APPENDIX C—QUALIFICATION FOR WELDERS OF LOW STRESS LEVEL PIPE

I. *Basic test.* The test is made on pipe 12 inches 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 1/8-inch 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 fittings and run pipe.

III. *Periodic tests for welders of small service lines.* Two samples of the welder's work each about 8 inches 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 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 prescribed in subparagraph (1) of this paragraph.

APPENDIX D—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. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

(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 subparagraph (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 subparagraphs (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 subparagraphs (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 buildup 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 the 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.

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 subparagraphs (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 paragraph 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 voltage equivalent to —0.85 volt as referred to a saturated copper-copper sulfate half cell:

(1) Saturated KC1 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.

WISCONSIN CODE ADOPTION OF PART 193 IN TITLE 49 CODE OF FEDERAL REGULATIONS

PART 193—LIQUEFIED NATURAL GAS FACILITIES: FEDERAL SAFETY STANDARDS

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Appendix A to Part 193— Incorporation by Reference

I. List of organizations and addresses

II. Documents Incorporated by Reference

Authority: 49 U.S.C. 1671 et seq.; 49 CFR 153, Appendix A of Part 1, and Appendix A of Part 106.

Subpart A—General

§ 193.2001 Scope of part. (a) This part precribes safety standards for LNG facilities used in the transportation of gas by pipeline that is subject to the Natural Gas Pipeline Safety Act of 1968 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 Semisolid facilities.** An LNG facility used in the transportation or storage of LNG in a semisolid state need not comply with any requirement of this part which the Director finds impractical or unnecessary because of the semisolid state of LNG. In making such a finding, the Director may impose appropriate alternative safety conditions.

§ **193.2005 Applicability.** (a) New or amended standards in this part governing the siting, design, installation, or construction of an LNG facility and related personnel qualifications and training do not apply to—

(1) LNG facilities under construction before the date such standards are published; or

(2) LNG facilities for which an application for approval of the siting, construction, or operation was filed before March 1, 1978, with the Department of Energy (or any predecessor organization of that Department) or the appropriate State or local agency in the case of any facility not subject to the jurisdiction of the Department of Energy under the Natural Gas Act (not including any facility the construction of which began after November 29, 1979, not pursuant to such an approval).

(b) If an LNG facility listed in paragraph (a) of this section is replaced, relocated, or significantly altered after February 11, 1980, the replacement, relocated facility, or significantly altered 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, not pursuant to an application for approval filed as provided by paragraph (a) (2) of this section before March 1, 1978; and

(2) To the extent compliance with the design, installation, and construction requirements would make the replaced, relocated, or altered facility incompatible with other facilities or would otherwise be impracticable, the replaced, relocated, or significantly altered facility may be designed, installed, or constructed in accordance with the original specifications for the facility, or in a manner that the Director finds acceptable.

(c) The siting, design, installation, and construction of an LNG facility under construction before February 11, 1980, or that is listed in paragraph (a) (2) of this section (except a facility under construction before July 1, 1976) must meet the applicable requirements of NFPA 59A (1972 edition) and Part 192 of this chapter or the applicable requirements of this part, except that no Part 192 standard issued after March 1, 1978, applies to an LNG facility listed in paragraph (a) (2) of this section.

§ **193.2007 Definitions.** As used in this part—

"Ambient vaporizer" means a vaporizer which derives heat from naturally occurring heat sources, such as the atmosphere, sea water, surface waters, or geothermal waters.

"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, and 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.

"Director" means Director of the Materials Transportation Bureau or any person to whom authority in the matter concerned has been delegated.

"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 metre per second^2 (32.17 feet per second^2).

"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 methand (CH_4) as its major constitutent which has been changed to a liquid or semisolid.

"LNG facility" means a pipeline facility that is used for liquefying or solidifying 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.

"m^3" 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, association, state, municipality, cooperative association, or joint stock association and includes any trustee, receiver, assignee, or personal representative thereof.

"Pipeline facility" means new and existing piping, 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.

"Piping" means pipe, tubing, hoses, fittings, valves, pumps, connections, safety devices or related components for containing the flow of hazardous fluids.

"Storage tank" means a container for storage a hazardous fluid, including an underground cavern.

"Transfer piping" means a system of permanent and temporary piping used for transferring hazardous fluids between any of the following: liquefaction process facilities, storage tanks, vaporizers, compressors, cargo transfer systems, and facilities other than pipeline facilities.

"Transfer system" includes transfer piping and cargo transfer system.

"Waterfront LNG plant" means an LNG plant with docks, wharves, piers, or other structures in, on, or immediately adjacent to the navigable waters of the United States or Puerto Rico and any shore area immediately adjacent to those waters to which vessels may be secured and at which LNG cargo operations may be conducted.

"Vaporization" means an addition of thermal energy changing a liquid or semisolid to a vapor or gaseous state.

"Vaporizer" means a heat transfer facility designed to introduce thermal energy in a controlled manner for changing a liquid or semisolid to a vapor or gaseous state.

§ **193.2009 Rules of regulatory construction.** (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 if 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 availalbe for inspection in the Materials Transportation Bureau, U.S. Department of Transportation, 400 Sevenenth Street, SW., Washington, D.C. 20590, and at the Office of the Federal Register Library, 1100 L Street, NW., Washington, D.C. In addition, copies of the incorporated materials are available from the respective organizations listed in Appendix A to this Part 193.

(c) Incorporated by reference provisions approved by the Director of the Federal Register.

(49 U.S.C. 1671(a); 49 CFR 1.53 and Appendix A to Part 1)

§ **193.2015 Petitions for finding or approval.** Where a rule in this part authorizes the Director to make a finding or approval, any operator may petition the Director to make such finding or approval. Petitions must be sent to the Director, Materials Transportation Bureau, 400 7th Street, SW., Washington, D.C. 20590, and be received at least 90 days before the operator requests that the finding or approval be made. 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. Within 9 days after a petition is received, the Director 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.

Subpart B—Siting Requirements

§ **193.2051 Scope.** This subpart prescribes siting requirements for the following LNG facilities: Containers and their impounding systems, transfer systems and their impounding systems, emergency shutdown control systems, fire control systems, and associated foundations, support systems, and normal or auxiliary power facilities necessary to maintain safety.

§ **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 Director or any State Agency that has submitted a current certification or agreement with respect to the plant under section 5 of the Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. 1674). 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 Director or the State Agency, after notice and opportunity for hearing, may require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

§ **193.2055 General.** An LNG facility must be located at a site of suitable size, topography, and configuration so that the facility can be designed to minimize the hazards to persons and offsite property resulting from leaks and spills of LNG and other hazardous fluids at the site. In selecting a site, each operator shall determine all site-related characteristics which could jeopardize the integrity and security of the facility. A site must provide ease of access so that personnel, equipment, and materials from offsite locations can reach the site for fire fighting or controlling spill associated hazards or for evacuation of personnel.

§ **193.2057 Thermal radiation protection.** (a) *Thermal exclusion zone.* Each LNG container and LNG transfer system must have a thermal exclusion zone in accordance with the following:

(1) Within the thermal exclusion zone, the impounding system may not be located closer in targets listed in paragraph (d) of this section than the exclusion distance "d" determined according to this section, unless the target is a pipeline facility of the operator.

(2) If grading and drainage are used under § 193.2149(b), operators must comply with the requirements of this section by assuming the space needed for drainage and collection of spilled liquid is an impounding system.

(b) *Measurement.* The exclusion distance "d" is measured along the line (PT), as shown in the following impoundment diagram, where the following apply:

(1) T is a point on the target that is closest to (P).

(2) D is a point closest to (T) on the top inside edge of the innermost dike.

(3) Θ is one of the following angles with the vertical, to account for flame tilt and potential preignition vapor formation:

(i) An assumed angle of $(\Theta)=45°$; or

(ii) An angle determined in accordance with a mathematical model that meets the criteria of paragraph (c) (2) of this section, using the maximum wind speed that is exceeded less than 5 percent of the time based on recorded data for the area.

(4) L is one of the following lengths to account for flame height:

(i) An assumed length of $(L)=6(A/\pi)^{05}$, where (A) is the horizontal area across the impounding space measured at the lowest point along the top inside edge of the dike; or

(ii) A length determined in accordance with a mathematical model that meets the criteria of paragraph (c) (2) of this section, using appropriate parameters consistent with the time period that a target could be subjected to exposure before harm would result.

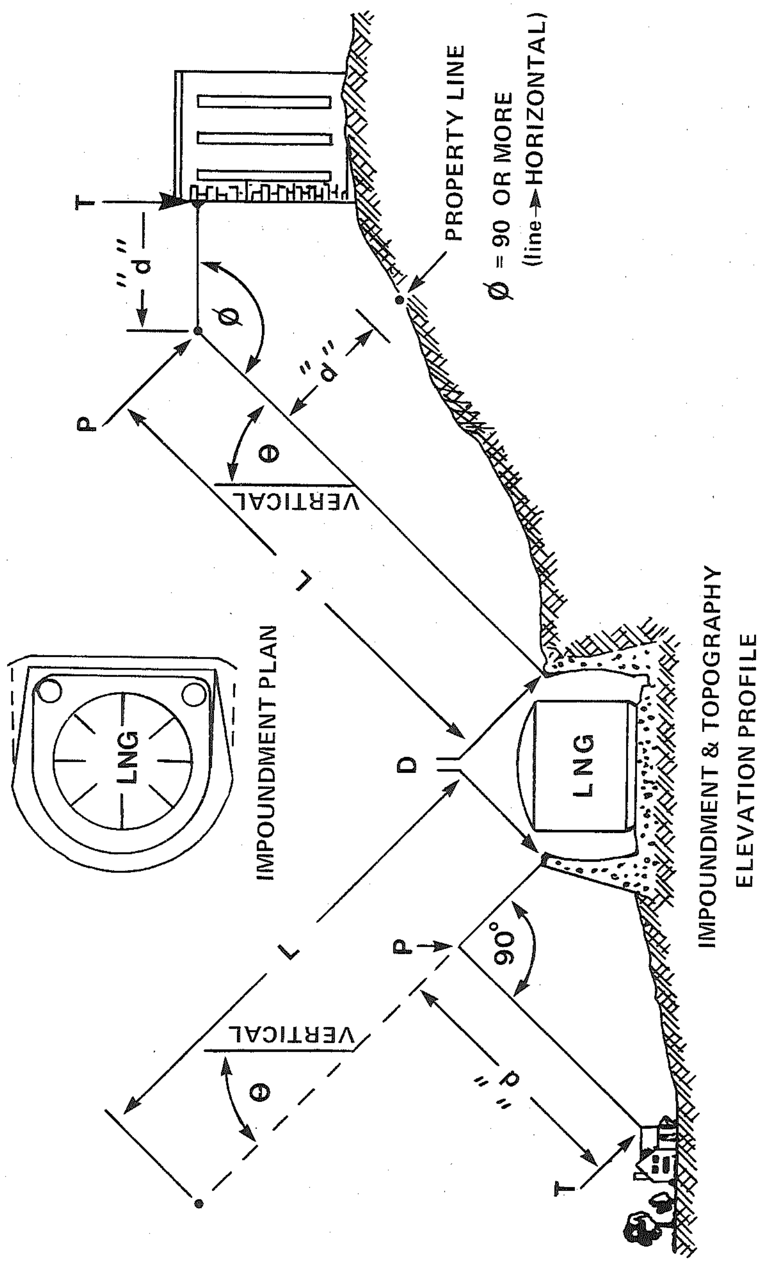
(5) PD is a line of length (L) or less, lying at angle Θ in the vertical plane that intersects points (D) and (T).

(6) PT is a line lying in the vertical plane of line (PD), that:

(i) Is perpendicular to line (PD) when (PD) is less than (L); or

(ii) Has an angular elevation not above the horizontal at (P) when (PD) equals (L);

(7) P is the point where (PT) and (PD) intersect.


IMPOUNDMENT PLAN
LNG
IMPOUNDMENT & TOPOGRAPHY
ELEVATION PROFILE
PROPERTY LINE
Ø = 90 OR MORE
(line→HORIZONTAL)
VERTICAL
VERTICAL
90°
P
T
L
D
"d"

(c) *Exclusion distance length.* The length of an exclusion distance for each impounding space may not be less than the distance "d" determined in accordance with one of the following:

(1) $d=(f)\ (A)^{05}$, where

A = the largest horizontal area across the impounding space measured at the lowest point along the top inside edge of the dike.

f=values for targets prescribed in paragraph (d) of this section.

(2) Determine "d" from a mathematical model for thermal radiation and other appropriate fire characteristics which assures that the incident thermal flux levels in paragraph (d) of this section are not exceeded. The model must:

(i) Use atmospheric conditions which, if applicable, result in longer exclusion distances than other atmospheric conditions occurring at least 95 percent of the time based on recorded data for the site area:

(ii) Have been evaluated and verified by testing at a scale, considering scaling effects, appropriate for the range of application:

(iii) Have been submitted to the Director for approval, with supportive data as necessary to demonstrate validity; and

(iv) Have received approval by the Director.

(d) *Limiting values for incident radiant flux on offsite targets.* The maximum incident radiant flux at an offsite target from burning of a total spill in an impounding space must be limited to the distances in paragraph (c) of this section using the following values of " (f) " or "Incident Flux":

Offsite target	(f)	Incident flux Btu/ft. ' hour
(1) Outdoor areas occupied by 20 or more persons during normal use, such as beaches, playgrounds, outdoor theaters, other recreation areas or other places of public assembly	(3)	1,600
(2) Buildings that are used for residences, or occupied by 20 or more persons during normal use	(1.6)	4,000
(3) Buildings made of cellulosic materials or are not fire resistant or do not provide durable shielding from thermal radiation that: (i) Have exceptional value, or contain objects of exceptional value based on historic uniqueness described in Federal, State, or local registers: (ii) Contain explosive, flammable, or toxic materials in hazardous quantities; or (iii) Could result in additional hazard if exposed to high levels of thermal radiation	(1.6)	4,000
(4) Structures that are fire resistant and provide durable shielding from thermal radiation that have the characteristics described in subdivisions (3) (i) through (3) (iii) above	(1.1)	6,700
(5) Public streets, highways, and mainlines of railroads	(1.1)	6,700
(6) Other structures, or if closer to (P), the right-of-way of the property	(0.8)	10,000

§ 193.2059 Flammable vapor-gas dispersion protection. (a) *Dispersion exclusion zone.* Except as provided by paragraph (e) of this section, each LNG container and LNG transfer system must have a dispersion exclusion zone with a boundary described by the minimum dispersion distance computed in accordance with this section. The following are prohibited in a dispersion exclusion zone unless it is an LNG facility of the operator:

(1) Outdoor areas occupied by 20 or more persons during normal use, such as beaches, playgrounds, outdoor theaters, other recreation areas, or other places of public assembly.

(2) Buildings that are:

(i) Used for residences:

(ii) Occupied by 20 or more persons during normal use:

(iii) Contain explosive, flammable, or toxic materials in hazardous quantities;

(iv) Have exceptional value or contain objects of exceptional value based on historic uniqueness described in Federal, State, or local registers; or

(v) Could result in additional hazard if exposed to a vapor-gas cloud.

(b) *Measuring dispersion distance.* The dispersion distance is measured radially from the inside edge of an impounding system along the ground contour to the exclusion zone boundary.

(c) *Computing dispersion distance.* A minimum dispersion distance must be computed for the impounding system. If grading and drainage are used under § 193.2149 (b), operators must comply with the requirements of this section by assuming the space needed for drainage and collection of spilled liquid is an impounding system. Dispersion distance must be determined in accordance with the following dispersion parameters, using applicable parts of the mathematical model in Appendix B of the report, "Evaluation of LNG Vapor Control Methods," 1974, or a model for vapor dispersion which meets the requirements of subdivisions (ii) through (iv) in § 193.2057 (c) (2):

(1) Average gas concentration in air = 2.5 percent.

(2) Dispersion conditions are a combination of those which result in longer predicted downwind dispersion distances than other weather conditions at the site at least 90 percent of the time, based on U.S. Government weather data, or as an alternative where the model used gives longer distances at lower wind speeds. Category F atmosphere, wind speed = 4.5 miles per hour, relative humidity equals 50.0 percent, and atmospheric temperatures = 0.0 C.

(3) Dispersion coordinates y, z, and H, where applicable, = O.

(d) *Vaporization design rate.* In computing dispersion distance under paragraph (c) of this section, the following applies:

(1) Vaporization results from the spill caused by an assumed rupture of a single transfer pipe (or multiple pipes that lack provisions to prevent parallel flow) which has the greatest overall flow capacity, discharging at maximum potential capacity, in accordance with the following conditions:

(i) The rate of vaporization is not less than the sum of flash vaporization and vaporization from boiling by heat transfer from contact surfaces during the time necessary for spill detection, instrument response, and automatic shutdown by the emergency shutdown system but, not less than 10 minutes, plus, in the case of impounding systems for LNG storage tanks with side or bottom penetrations, the time necessary for the liquid level in the tank to reach the level of the penetrations or equilibrate with the liquid impounded assuming failures of the internal shut-off valve.

(ii) In determining variations in vaporization rate due to surface contact, the time necessary to wet 100 percent of the impounding floor area shall be determined by equation C-9 in the report "Evaluation of LNG Vapor Control Methods," 1974, or an alternate model which meets the requirements of subdivisions (ii) through (iv) in § 193.2057 (c) (2).

(iii) After spill flow is terminated, the rate of vaporization is vaporization of the remaining spillage, if any, from boiling by heat transfer from contact surfaces that are reducing in area and temperature as a function of time.

(iv) Vapor detention space is all space provided for liquid impoundment and vapor detention outside the component served, less the volume occupied by the spilled liquid at the time the vapor escapes the vapor detention space.

(2) The boiling rate of LNG on which dispersion distance is based is determined using the weighted average value of the thermal properties of the contact surfaces in the impounding space determined from eight representative experimental tests on the materials involved. If surfaces are insulated, the insulation must be designed, installed, and maintained so that it will retain its performance characteristics under spill conditions.

(e) *Planned vapor control.* An LNG facility need not have a dispersion exclusion zone if the Director finds that compliance with paragraph (a) of this section would be impractical and the operator prepares and follows a plan for controlling LNG vapor that is found acceptable by the Director. The plan must include circumstances under which LNG vapor is controlled to preclude the dispersion of a flammable mixture from the LNG facility under all predictable environmental conditions that could adversely affect control. The reliability of the method of control must be demonstrated by testing or experience with LNG spills.

§ 193.2061 Seismic investigation and design forces. (a) Except for shop fabricated storage tanks of 70,000 gallons or less capacity mounted within 2 feet of the ground, if an LNG facility is located at a site in Zone O or 1 of the "Seismic Risk Map of the United States," UBC, each operator shall determine, based on a study of faults, hydrologic regime, and soil conditions, whether a potential exists at the site for surface faulting or soil liquefaction.

(b) Subject to paragraph (f) of this section LNG facilities must be designed and built to withstand, without loss of structural or functional integrity, the following seismic design forces, as applicable:

(1) For LNG facilities (other than shop fabricated storage tanks of 70,000 gallons or less capacity mounted within 2 feet of the ground) located at a site in Puerto Rico in Zone 2, 3, or 4 of the "Seismic Risk Map of the United States," or at a site determined under paragraph (a) of this section to have a potential for surface faulting or soil liquefaction, the forces that could reasonably be expected to occur at the foundation of the facility due to the most critical ground motion, motion amplification, permanent differential ground displacement, soil liquefaction, and symmetric and assymmetric reaction forces resulting from hydrody-

namic pressure and motion of contained liquid in interaction with the facility structure.

(2) For all other LNG facilities, the total lateral force set forth in UBC, Volume 1, corresponding to the zone of the "Seismic Risk Map of the United States" in which the facility is located, and a vertical force equal to the total lateral force.

(c) Each operator of an LNG facility to which paragraph (b) (1) of this section applies shall determine the seismic design forces on the basis of a detailed geotechnical investigation and in accordance with paragraphs (d) and (e) of this section. The investigation must include each of the following items that could reasonably be expected to affect the site and be sufficient in scope to identify all hazards that could reasonably be expected to affect the facility design:

(1) Identification and evaluation of faults. Quaternary activity of those faults, tectonic structures, static and dynamic properties of materials underlying the site, and, as applicable, tectonic provinces within 100 miles of the site:

(2) Identification and evaluation of all historically reported earthquakes which could affect the determination under this section of the most critical ground motion or differential displacement at the site when correlated with particular faults, tectonic structures, and tectonic provinces, as applicable; and

(3) Identification and evaluation of the hydrologic regime and the potential of liquefaction-induced soil failures.

(d) The most critical ground motion must be determined in accordance with paragraph (e) of this section either:

(1) Probabilistically, when the available earthquake data are sufficient to show that the yearly probability of exceedance of most critical ground motion is 10^{-4} or less; or

(2) Deterministically, when the available earthquake data are insufficient to provide probabilistic estimates, with the objective of determining a most critical ground motion with a yearly probability of exceedance of 10^{-4} or less.

(e) The determination of most critical ground motion, considering local and regional seismological conditions, must be made by using the following:

(1) A regionally appropriate attenuation relationship, assuming that earthquakes occur at a location on a fault, tectonic structure, or tectonic province, as applicable, which would cause the most critical seismic movement at the site, except that where epicenters of historically reported earthquakes cannot be reasonably related to known faults or tectonic structures, but are recognized as being within a specific tectonic province which is within 100 miles of the site, assume that those earthquakes occur within their respective provinces at a source closest to the site.

(2) A horizontal design response spectrum determined from the mean plus one standard deviation of a freefield horizontal elastic response spectra whose spectral amplitudes are consistent with values expected for the most critical ground motion.

(3) A vertical design response spectrum that is either two-thirds of the amplitude of the horizontal design response spectrum at all frequencies or equal to the horizontal design response spectrum where the site is located within 10 miles of the earthquake source.

(f) An LNG storage tank or its impounding system may not be located at a site where an investigation under paragraph (c) of this section shows that any of the following conditions exists unless the Director grants an approval for the site:

(1) The estimated design horizontal acceleration exceeds O ag at the tank or dike foundation.

(2) The specific local geologic and seismic data base is sufficient to predict future differential surface displacement beneath the tank and dike area, but displacement not exceed ag 30 inches cannot be assured with a high level of confidence.

(3) The specific local geologic and seismic data base is not sufficient to predict future differential surface displacement beneath the tank and dike area, and the estimated cummulative displacement of a Quarternary fault within one mile of the tank foundation exceeds 60 inches.

(4) The potential for soil liquefaction cannot be accommodated by design and construction in accordance with paragraph (b) (1) of this section.

(g) An application for approval of a site under paragraph (f) of this section must provide at least the following:

(1) A detailed analysis and evaluation of the geologic and seismic characteristics of the site based on the geotechnical investigation performed under paragraph (c) of this section, with emphasis on prediction of near field seismic response.

(2) The design plans and structural analysis for the tank, its impounding system, and related foundations, with a report demonstrating that the design requirements of this section are satisfied, including any test results or other documentation as appropriate.

(3) A description of safety-related features of the site or designs, in addition to those required by this part, if applicable, that would mitigate the potential effects of a catastrophic spill (e.g., remoteness or topographic features of the site, aditional exclusion distances, or multiple barriers for containing or impounding LNC).

(b) Each container which does not have a structurally liquid-tight cover must have sufficient freeboard with an appropriate configuration to prevent the escape of liquid due to sloshing, wave action, and vertical liquid displacement caused by seismic action.

§ 192.2063 Flooding. (a) Each operator shall determine the effects of flooding on an LNG facility site based on the worst occurrance in a 100-year period. The determination must take into account:

(1) Volume and velocity of the floodwater;

(2) Tsunamis (local, regional, and distant);

(3) Potential failure of dams;

(4) Predictable land developments which would affect runoff accumulation of water, and

(5) Tidal action.

(b) The effect of flooding determined under paragraph (a) of this section must be accommodated by location or design and construction, as applicable, to reasonably assure:

(1) The structural or functional integrity of LNG facilities; and

(2) Access from outside the LNG facility and movement of personnel and equipment about the LNG facility site for the control of fire and other emergencies.

§ 192.2065 Soil characteristics. (a) Soil investigations including borings and other appropriate tests must be made at the site of each LNG facility to determine bearing capacity, settlement characteristics, potential for erosion, and other soil characteristics applicable to the integrity of the facility.

(b) The naturally occurring or designed soil characteristics at each LNG facility site must provide load bearing capacities, using appropriate safety factors, which can support the following loads without excessive lateral or vertical movement that causes a loss of the functional or structural integrity of the facility involved:

(1) Static loading caused by the facility and its contents and any hydrostatic testing of the facility; and

(2) Dynamic loading caused by movement of contents of the facility during normal operation, including flow, sloshing, and rollover.

§ 193.2057 Wind forces. (a) LNG facilities must be designed to withstand without loss of structural or functional integrity:

(1) The direct effect of wind forces;

(2) The pressure differential between the interior and exterior of a confining, or partially confining, structure; and

(3) In the case of impounding systems for LNG storage tanks, impact forces and potential penetrations by wind borne missiles.

(b) The wind forces at the location of the specific facility must be based on one of the following:

(1) For shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, applicable wind load data in ANSIA 58.1, 1972 edition.

(2) For all other LNG facilities—

(i) An assumed sustained wind velocity of not less than 200 miles per hour, unless the Director finds a lower velocity is justified by adequate supportive data; or

(ii) The most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of excedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable.

§ **193.2069 Other severe weather and natural conditions.** (a) In addition to the requirements of §§ 193.2061, 193.2063, 193.2065, and 193.2067, each operator shall determine from historical records and engineering studies the worst effect of other weather and natural conditions which may predictably occur at an LNG facility site.

(b) The facility must be located and designed so that such severe conditions cannot reasonably be expected to result in an emergency involving the factors listed in § 193.2063 (b).

§ **193.2071 Adjacent activities.** (a) Each operator shall determine that present and reasonably foreseeable activities adjacent to an LNG facility site that could adversely affect the operatiion of the LNG facility or the safety of persons or offsite property, if damage to the facility occurs.

(b) An LNG facility must not be located where present or projected offsite activities would be reasonably expected to—

(1) Adversely affect the operation of any of its safety control systems:

(2) Cause failure of the facility; or

(3) Cause the facility not to meet the requirements of this part.

§ **193.2073 Separation of facilities.** Each LNG facility site must be large enough to provide for minimum separations between facilities and between facilities and the site boundary to—

(a) Permit movement of personnel, maintenance equipment, and emergency equipment around the facility; and

(b) Comply with distances specified in Sections 2-2.4 through 2-2.7 of NEDA 59A.

Subpart C—Design

§ **193.2101 Scope.** This subpart prescribes requirements for the selection and qualification of materials for components, and for the design and installation or construction of componants and buildings, including separate requirements for impounding systems, LNG storage tanks, and transfer systems.

Materials

§ **193.2103 General.** Materials for all components must be—

(a) Able to maintain their structural integrity under all design loadings, including applicable environmental design forces under Subpart B of this part:

(b) Physically, chemically, and thermally compatible within design limits with any fluid or other materials with which they are in contact; and

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

§ **193.2105 Extreme temperatures; normal operations.** Each operator shall—

(a) Determine the range of temperatures to which components will be subjected during normal operations, including required testing, initial startup, cooldown operations, and shutdown conditions; and

(b) Use component materials that meet the design standards of this part for strength, ductility, and other properties throughout the entire range of temperatures to which the component will be subjected in normal operations.

§ 193.2107 **Extreme temperatures, emergency conditions.** (a) Each operator shall determine the effects on components not normally exposed to extreme cold (including a component's foundation or support system) of contact by LNG or cold refrigerant that could result from error, a spill, or other emergency determined as required by this part.

(b) Each operator shall determine the effects on components (including their foundations or support systems) of the extreme heat which could result from an LNG or other hazardous fluid fire.

(c) Where the exposure determined under paragraph (a) or (b) of this section could result in a failure that would worsen the emergency, the component or its foundation or support system, as appropriate, must be:

(1) Made of material or constructed to be suitable for the extreme temperature to which it could be subjected; or

(2) Protected by insultation or other means that will delay failure due to extreme temperature in order to allow adequate time to take emergency responses.

(d) If a material that has low resistance to flame temperatures is used in any component containing a hazardous fluid, the material must be protected so that any heat resulting from a controllable emergency does not cause the release of fluid that would result in an uncontrollable emergency.

§ **193.2109 Insulation.** During normal operations, insulation materials must—

(a) Maintain insulating values;

(b) Withstand thermal and mechanical design loads; and

(c) Be covered with a material that is noncombustible in the installed state, is not subject to detrimental ultraviolet decay, and that can withstand the forces of wind according to ANSI A58.1 and anticipated loading which could occur in a controllable emergency.

§ **193.2111 Cold boxes.** All cold boxes must be made of noncombustible material and the insulation must be made of materials which are noncombustible in the installed condition.

§ **193.2113 Piping.** (a) Piping made of cast iron, malleable iron, or ductile iron may not be used to carry any cryogenic or hazardous fluids.

(b) Piping materials intended for normal use at temperatures below —28.9°C (—20°F) or for use under § 193.2107 (c) (1) must be qualified by testing in accordance with ANSI B 31.3 to comply with § 193.2103 (b).

§ 193.2115 Concrete subject to cryogenic temperatures. Concrete intended for normal use at cryogenic temperatures or for use under § 193.2107 (c) (1) may not be used unless—

(a) Materials, measurements, mixing, placing, prestressing, and post-stressing of concrete meets generally accepted engineering practices;

(b) Metallic reinforcing, prestressing wire, structural and nonstructural members used in concrete are acceptable in the installed condition for the temperature and stress levels encountered at design loading conditions; and

(c) Tests for the compressive strength, the coefficient of contraction, an acceptable thermal gradient, and, if applicable, acceptable surface loading to prevent detrimental spalling are performed on the concrete at the lowest temperature for which the concrete is designed or similar test data on these properties are available.

§ 193.2117 Combustible materials. Combustible materials are not permitted for the construction of buildings, plant equipment, and the foundations and supports of buildings and plant equipment in areas where ignition of the material would worsen an emergency. However, limited combustible materials may be used when the use of noncombustible materials is impractical.

§ 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 itrem concerned.

Design of Components and Buildings

§ 193.2121 General. Components, including their foundations and support systems, must be designed, fabricated, and installed to withstand, without loss of functional or structural integrity, predictable loadings not including environmental design forces under Subpart B of this part unless applicable under that subpart.

§ 193.2123 Valves. (a) Each valve, including control valves and relief valves, must be designed, manufactured, and tested to comply with ANSI B31.3 or ANSI B31.5 or ANSI B 31.8 or API Standard 6D, if design conditions fall within their scope.

(b) Extended bonnet valves must be used for service temperatures below —45.6° C (—50°F).

(c) Valves used for cryogenic liquid service must be designed to operate in the position in which they are installed.

(d) Powered local and remote operation must be provided for valves intended for use during a controllable emergency that would be difficult or excessively time consuming to operate manually during such an emergency.

(e) Valves must be designed and installed so that an excessive load on the piping system does not render the valve inoperable.

§ 193.2125 Automatic shutoff valves. Each automatic shutoff valve or combination of valves must—

(a) Have a fail-safe design;

(b) Operate to stop fluid flow which would endanger the operational integrity of plant equipment; and

(c) Close at a rate to avoid fluid hammer which would endanger the operating integrity of a component.

§ **193.2127 Piping.** (a) Piping must be designed, manufactured, and tested to comply with ANSI B 31.3.

(b) All cryogenic and hazardous fluid piping must have connections to facilitate blowdown and purge as required by this part.

(c) Each cryogenic or hazardous fluid piping system that is aboveground must be identified by color coding, painting, or labeling.

(d) Seamless pipe or pipe with a longitudinal joint effiently of 1.0 determined in accordance with ANSI B31.3 or pipe with a design pressure less than two-thirds of the mill-proof test pressure or subsequent shop or field hydrostatic test pressure must be used for process and transfer piping handling cryogenic or other hazrdous fluids with a service temperature below —22° F (—30°C).

(e) For longitudinal or spiral weld piping handling LNG or cryogenic fluids, the heat affected zone must comply with § 323.2.2 of ANSI B31.3.

(f) Threaded piping used in hazardous fluid service must be at least Schedule 80.

§ **193.2129 Piping attachments and supports.** Piping attachments and supports for LNG or refrigerant piping must be designed to prevent excessive heat transfer which can result in either unintentional restraint of piping caused by ice formations or the embrittlement of supporting steel.

§ **193.2131 Building design.** (a) Each building or structural enclosure in which potentially hazardous quantities of flammable materials are handled must be designed and constructed to minimize fire hazards.

(b) Buildings or structural enclosures in which hazardous or cryogenic fluids are handled shall be of light-weight, noncombustible construction with nonload-bearings walls.

(c) If rooms containing such fluids are located within or attached to buildings in which such fluids are not handled, i.e., control rooms, shops, etc., the common walls shall be limited to not more than two in number, shall be designed to withstand a static pressure of at least 4800 Pa (100 psf). have no doors or other communicating openings, and shall have a fire resistance rating of at least 1 hour.

§ **193.2133 Buildings; ventilation.** (a) Each building in which potentially hazardous quantities of flammable fluids are handled must be ventilated to minimize the possibility, during normal operation, of hazardous accumulation of a flammable gas and air mixture, hazardous products of combustion, and other hazardous vapors in enclosed process areas by one of the following means:

(1) A continuously operating mechancial ventilation system:

(2) A combination gravity ventilation system and normally off mechanical ventilation system which is activated by suitable flammable

gas detectors at a concentration not exceeding 25 percent of the lower flammable limit of the gas;

(3) A dual rate mechanical ventilation system with the high rate activated by suitable flammable gas detectors at a concentration not exceeding 25 percent of the lower flammable limit of the gas; or

(4) A gravity ventilation system composed of a combination of wall openings, roof ventilators, and, if there are basements or depressed floor levels, a supplemental mechanical ventilation system.

(b) The ventilation rate must be at least 1 cubic foot per minute of air per square foot of floor area. If vapors heavier than air can be present, the ventilation must be proportioned, according to the area of each level.

§ 193.2135 Expansion or contraction. Each operator shall consider the amount of contraction and expansion of each component during operating and environmental thermal cycling and shall—

(a) Provide components that operate without detrimental stress or restriction of movement, within each component and between components, caused by contraction and expansion; and

(b) Prevent ice buildup from detrimentally restricting the movement of components caused by contraction and expansion.

§ 193.2137 Frost heave. (a) Each operator shall—

(1) Determine which components and their foundations could be endangered by frost heave from ambient temperatures or operating temperatures of the component; and

(2) Provide protection against frost heave which might impair their structural integrity.

(b) For each component and foundation determined under paragraph (a) of this section, instrumentation must be installed to warn of potential structural impairment due to frost heave, unless the operator includes in the maintenance procedures required by this part, a method and schedule of inspection that will detect changes in the elevation.

§ 193.2139 Ice and snow. (a) Components must be designed to support the weight of ice and snow which could normally collect or form on them.

(b) Each operator shall provide protection for components from falling ice or snow which may accumulate on structures.

(c) Valves and moving components must not become inoperative due to ice formation on the component.

§ 193.2141 Electrical systems. (a) Each operator shall select and install electrical equipment and wiring for components in accordance with NFPA-70 and, where applicable Section 7-62 of NFPA-59A.

(b) Electrical grounding and bonding must be in accordance with Section 7-7.1.1 of NFPA-59A.

(c) Protective measures for stray or impressed currents must be provided in accordance with Section 7-7.3 of NFPA-59A.

§ **193.2143 Lightning.** Each operator shall install proper grounds as necessary to minimize the hazard to plant personnel and components, including all electrical circuits, as a result of lightning.

§ **193.2145 Boilers and pressure vessels.** Boilers must be designed and fabricated in accordance with Section I or Section IV of the ASME Boiler and Pressure Vessel Code. Other pressure vessels subject to that Code must be designed and fabricated in accordance with Division 1 or Division 2 of Section VIII.

§ **193.2147 Combustion engines and turbines.** Combustion engines and gas turbines must be installed in accordance with NFPA-37.

Impoundment Design and Capacity

§ **193.2149 Impoundment required.** (a) An impounding system must be provided for storage tanks to contain a potential spill of LNG or other hazardous liquid.

(b) Grading or drainage or an impounding system must be provided to ensure that accidental spills or leaks from the following components and areas do not endanger components or adjoining property or enter navigable waterways:

(1) Liquefaction and other process equipment;

(2) Vaporizers;

(3) Transfer systems;

(4) Parking areas for tank cars or tank trucks; and

(5) Areas for loading, unloading, or storing portable containers and dewar vessels.

(c) Impounding systems for LNG must be designed and constructed in accordance with this subpart. Impounding systems intended for containment of hazardous liquids other than LNG must meet the requirements of NFPA-30.

§ **193.2151 General design characteristics.** (a) An impounding system must have a configuration or design which, to the maximum extent possible, will prevent liquid from escaping impoundment by leakage, splash from collapse of a structure or part thereof, momentum and low surface friction, foaming, failure of pressurized piping, and accidental pumping.

(b) The basic form of an impounding system may be excavation, a natural geological formation, manufactured diking, such as berms or walls, or any combination thereof.

§ **193.2153 Classes of impounding systems.** (a) for the purpose of this part. impounding systems are classified as follows:

Class 1. A system which surrounds the component served with the inner surface of the dike constructed against or within 24 inches of the component served.

Class 2. A system which surrounds the component or area served with the dike located a distance away from the component or at the periphery of the area.

Class 3. A system which conducts a spill by dikes and floors to a remote impounding space which does not surround the component or area served.

(b) In the case of an impounding system consisting of a combination of classes, requirements of this part regarding a single class apply according to the percentage of impoundment provided by each class.

§ **193.2155 Structural requirements.** (a) Subject to paragraph (b) of this section, the structural parts of an impounding system must be designed and constructed to prevent impairment of the system's performance reliability and structural integrity as a result of the following:

(1) The imposed loading from—

(i) Full hydrostatic head of impounded LNG;

(ii) Hydrodynamic action, including the effect of any material injected into the system for spill control;

(iii) The impingement of the trajectory of an LNG jet discharged at any predictable angle; and

(iv) 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) For spills from LNG storage tanks with Class 2 or 3 impounding systems, imposed loading and surging flow characteristics must be based on a credible release of the tank contents.

(c) If an LNG storage tank is located within a horizontal distance of 6,100 m. (20,000 ft.) from the nearest point of the nearest runway serving large aircraft as defined in 14 CFR Part 1.1 a Class 1 impounding system must be used which is designed to withstand collision by, or explosion of, the heaviest aircraft which can take off or land at the airport.

§ **193.2157 Coatings and coverings.** Insulation, sealants, or other coatings and coverings which are part of an impounding system—

(a) Must be noncombustible in an installed condition when exposed to an LNG fire resulting from a spill that covers the floor of the impounding space:

(b) Must withstand exposure to fire from sources determined as required by this part, other than impounded LNG, for a period of time until fire protective or fire extinguishing action is taken; and

(c) When used for the purpose of maintaining the functional integrity of an impounding system, must be capable of withstanding sudden exposure to LNG without loss of such integrity.

§ 193.2159 **Floors.** Floors of Class 2 and Class 3 impounding systems must, to the extent feasible—

(a) Slope away from the component or item impounded and to a sump basin installed under § 193.2171;

(b) Slope away from the nearest adjacent component;

(c) Drain surface waters from the floor at rates based on a storm of 10-year frequency and 1-hour duration and other natural water sources; and

(d) Be designed to minimize the wetted floor area.

§ **193.2161 Dikes, general.** (a) Penetrations in dikes to accommodate piping or any other purpose are prohibited.

(b) An outer wall of a component served by an impounding system may not be used as a dike except for a concrete wall designed to comply with the requirements of § 193.2155(c) or equivalent design impact loading.

§ **193.2163 Vapor barriers.** If vapor barriers are installed in meeting the requirements of § 193.2059, they must be designed and constructed to detain LNG vapor.

§ **193.2165 Dike dimensions.** In addition to dike dimensions needed to comply with other requirements of this subpart, to minimize the possibility that a trajectory of accidentally discharged liquid would pass over the top of a dike, the horizontal distance from the inner wall of the component or vessel served to the closest inside edge of the top of the dike must at least equal the vertical distance from the maximum liquid level in the component or vessel to the inside edge of the top of the dike.

§ **193.2167 Covered systems.** (a) A covered impounding system is prohibited unless it is—

(1) Sealed from the atmosphere and filled with an inert gas; or

(2) Permanently interconnected with the vapor space of the component served.

(b) Flammable nonmetallic membranous covering is prohibited in a covered system.

(c) For systems to which paragraph (a)(1) of this section applies, instrumentation and controls must be provided to—

(1) Maintain pressures at a safe level; and

(2) Monitor gas concentrations in accordance with § 193.2169.

(d) Dikes must have adequate structural strength to assure that they can withstand impact from a collapsed cover and all anticipated conditions which could cause a failure of the impounding space cover.

§ **193.2169 Gas leak detection.** Appropriate areas within an impounding system where collection or passage of LNG or LNG vapor could be expected must be equipped with sensing and warning devices to monitor continously for the presence of LNG or LNG vapor and to warn before LNG gas concentration levels exceed 25 percent of the lower flammable limit.

§ **193.2171 Sump basins.** Except for Class 1 impounding systems, a sump basin must be located in each impounding system for collection of water.

§ **193.2173 Water removal.** (a) Except for Class 1 systems, impounding systems must have sump pumps and piping running over the dike to remove water collecting in the sump basin.

(b) The water removal system must have adequate capacity to remove water at rates which equal the maximum predictable collection rate from a storm of 10-year frequency and 1-hour duration, and other natural causes.

(c) Sump pumps for water removal must—

(1) Be operated as necessary to keep the impounding space as dry as practical; and

(2) If sump pumps are designed for automatic operation, have reduntant automatic shutdown controls to prevent operation when LNG is present.

§ **193.2176 Shared impoundmant.** When an impounding system serves more than one LNG storage tank, a means must be provided to prevent low temperature or fire resulting from leakage from any one of the storage tanks served causing any other storage tank to leak. The means must not result in a vapor dispersion distance which exceeds the exclusion zone required by § 193.2059.

§ **193.2179 Impoundment capacity; general.** In addition to capacities otherwise required by this subpart, an impounding system must have sufficient volumetric capacity to provide for—

(a) Displacement by the component, tank car, tank truck, container, or dewar vessal served; and

(b) Where applicable, displacement which could occur when a higher density substance than the liquid to be impounded enters the system, considering all relevant means of assuring capacity.

§ **193.2181 Impoundment capacity, LNG storage tanks.** (a) Except as provided in paragraph (b) of this section, each impounding system serving an LNG storage tank must have a minimum volumetric liquid impoundment capacity as follows:

Number of tanks in system	Class or type of system	System capacity in percent of LNG tank's maximum liquid capacity
1	Class 1	110 percent.
	Classes 2 and 3	150 percent.
More than 1	Classes 2 and 3	100 percent of all tanks or 150 percent of largest tank, whichever is greater.

(b) For purposes of this section, a covered impounding system serving a single LNG storage tank may have a capacity of 110 percent of the LNG tank's maximum liquid capacity if it is covered by a roof that is separate and independent from the LNG storage tank.

§ 193.2183 Impoundment capacity; equipment and transfer systems. If an impounding system serves a component under § 193.2149 (b) (1) - (3), it must have a minimum volumetric liquid impoundment capacity equal to the sum of—

(a) One-hundred percent of the volume of liquid that could be contained in the component and, where applicable, tank car or tank truck served; and

(b) The maximum volume of liquid which could discharge into the impounding space from any single failure of equipment or piping during the time period necessary for spill detection, instrument response, and sequenced shutdown by the automatic shutdown system under § 193.2439.

§ 193.2185 Impoundment capacity; parking areas, portable containers. Each impounding system serving an area listed under § 193.2149 (b) (4) or (5) must have a minimum volumetric liquid impoundment capacity which complies with the requirements of § 193.2181, assuming each tank car, tank truck, portable container, or dewar vessel to be a storage tank.

LNG Storage Tanks

§ 193.2187 General. (a) LNG storage tanks must comply with the requirements of this subpart and the other applicable requiremens of this part.

(b) A flammable nonmetallic membrane liner may not be used as an inner container in a storage tank.

§ 192.2189 Loading forces. Each part of an LNG storage tank must be designed to withstand without loss of functional or structural integrity any predictable combination of forces which would result in the highest stress to the part, including the following:

(a) Internal design pressure determined under § 193.2197.

(b) External design pressure determined under § 193.2199.

(c) Weight of the structure.

(d) Weight of liquid to be stored, except that in no case will the density assumed be less than 29.3 pounds per cubic foot (470 kilograms per cubic meter).

(e) Loads due to testing required by § 193.2327.

(f) Nonuniform reaction forces on the foundation due to predictable settling and other movement.

(g) Superimposed forces from piping, stairways, and other connected appurtenances.

(h) Predictable snow and ice loads.

(i) The loading of internal insulation on the inner container and outer shell due to compaction and movement of the container and shell over the design life of the insulation.

(j) In the case of vacuum insulation, the forces due to the vacuum.

(k) In the case of a positive pressure purge, the forces due to the maximum positive pressure of the purge gas.

§ 193.2191 Stratification. LNG storage tanks with a capacity of 5,000 barrels or more must be equipped with means to mitigate a potential for rollover and overpressure such as:

(a) Selective filling at the top and bottom of the tank;

(b) Circulating liquid from the bottom to the top of the same tank; or

(c) Transferring liquid selectively from the bottom of the tank to the bottom or top of any adjacent storage tank.

§ 193.2193 Movement and stress. (a) Each operator shall determine for normal operations of each LNG storage tank—

(1) The amount and pattern of predictable movement of components. Including transfer piping, and the foundation, which could result from thermal cycling, loading forces, and ambient air changes; and

(2) For a storage tank with an inner container, the predictable movement of the inner container and the outer shell in relation to each other.

(b) Storage tanks must be designed to provide adequate allowance for stress due to movement determined under paragraph (a) of this section, including provisions that—

(1) Backfill does not cause excessive stresses on the tank structure due to expansion of the storage tank during warmup;

(2) Insulation does not settle to a damaging degree or unsafe condition during thermal cycling; and

(3) Expansion bends and other expansion or contraction devices are adequate to prevent excessive stress on tank penetrations, especially during cooldown from ambient temperatures.

§ 193.2195 Penetrations. (a) All penetrations in an LNG storage tank must be designed in accordance with API 620, including Appendix Q.

(b) The loadings on all penetrations must be determined by an analysis of all contributing forces, including those from tank thermal movements, connecting piping thermal movements, hydraulic forces, applicable wind and earthquake forces, and the forces resulting from settlement or movement of the tank foundation or pipe supports.

(c) All penetrations in an LNG storage tank below the design liquid level must be fitted with an internal shutoff valve which is designed and installed so that any failure of the nozzle penetrating the tank will be outside the tank.

(d) The requirements of paragraphs (a) and (c) of this sectrion do not apply to shop fabricated tanks of 70,000 gallons or less capacity. All penetrations in such tanks must be designed and installed in accordance with the applicable provisions of Section VIII. Division 1 of the ASME Boiler and Pressure Vessel Code.

§ **193.2197 Internal design pressure.** (a) Each operator shall establish the internal design pressure at the top of each LNG storage tank, including a suitable margin above the maximum allowable working pressure.

(b) The internal design pressure of a storage tank may not be lower than the highest pressure in the vapor space resulting from each of the following events or combination thereof that predictably might occur, giving consideration to vapor handling equipment, relief devices in accordance with § 193.2429, and any other mitigating measures:

(1) Filling the tank with LNG including effects of increased vaporization rate due to superheat and sensible heat of the added liquid;

(2) Rollover.

(3) Fall in barometric pressure, using the worst combination of amount of fall and rate of fall which might predictably occur:

(4) Loss of effective insulation that may result from an adjacent fire, leak of liquid into the intertank space, or other predictable accident; and

(5) Flash vaporization resulting from pump recirculation.

§ **193.2199 External design pressure.** (a) Each operator shall establish the external design pressure at the top of each LNG storage tank, including a suitable margin below the minimum allowable working pressure.

(b) The external design pressure may not be higher than the lowest vapor pressure in the vapor space resulting from each of the following events or combinations thereof that predictably might occur, giving consideration to gas makeup systems, vacuum relief devices in accordance with § 193.2429, and any other mitigating measures.

(1) Withdrawing liquid from the tank;

(2) Withdrawing gas from the tank;

(3) Adding subcooled LNG to the tank; and

(4) Rise in barometric pressure, based on the worst combination of amount of rise and rate of rise which predictably might occur.

§ 193.2201 Internal temperature. The liquid container of each LNG storage tank and all tank parts used in contact with LNG or its cold vapor shall be designed for the lowest bulk liquid temperature which can be attained in the LNG storage tank.

§ 193.3203 Foundation. (a) Each LNG storage tank must have a stable foundation designed in accordance with generally accepted structural engineering practices.

(b) Each foundation must support design loading forces without detrimental settling that could impair the structural integrity of the tank.

§ 193.2206 Frost heave. If the protection provided for LNG storage tank foundations from frost heave under § 193.2137 (a) includes heating the foundation area—

(a) An instrumentation and alarm system must be provided to warn of malfunction of the heating system; and

(b) A means to correct the malfunction must be provided.

§ 193.2207 Insulation. (a) Insulation on the outside of the outer shell of an LNG storage tank may not be used to maintain stored LNG at an operating temperature during normal operation.

(b) Insulation between an inner container and the outer shell of an LNG storage tank must—

(1) Be compatible with the contained liquid and its vapor:

(2) In its installed condition, be noncombustible; and

(3) Not significantly lose insulating properties by melting, settling, or other means due to a fire resulting from a spill that covers the floor of the impounding space around the tank.

§ 193.2209 Instrumentation for LNG storage tanks. (a) LNG storage tank having a capacity over 70,000 gallons must be equipped with a sufficient number of sensing devices and personnel warning devices, as prescribed, which operate continuously while the tank is in operation to assure that each of the following conditions is not a potential hazard to the structural integrity or safety of the tank:

Condition	Instrumentation
(1) Amount of liquid in the tank.	Redundant liquid level gages and recorders with high level alarms, and a minimum of one independent high level alarm.
(2) Vapor pressure within the tank.	Redundant gages and recorders with high and low pressure alarms.
(3) Temperatures at representative critical points in the foundation.	Temperature indicating and recording devices with alarm.
(4) Temperature of contained liquid at various vertical intervals.	Temperature recorders.
(5) Abnormal temperature in tank structure.	Thermocouples located at representative critical points with recorders.
(6) Excessive relative movement of inner container and outer shell.	Linear and rotational movement indicators located between inner container and outer shell with recorders.

(b) LNG storage tanks with a capacity of 70,000 gallons or less must be equipped with the following:

(1) LNG liquid trycocks, when attended during the filling operation.

(2) Pressure gages and recorders with high pressure alarm.

(3) Differential pressure liquid level gage.

(c) Each storage tank must be designed as appropriate to provide for compliance with the inspection requirements of this part.

§ **193.2211 Metal storage tanks.** (a) Metal storage tanks with internal design pressures of not more than 15 psig must be designed and constructed in accordance with API Standard 620 and, where applicable, Appendix Q of that standard.

(b) Metal storage tanks with internal design pressures above 15 psig must be designed in accordance with the applicable division of Section VIII of the ASME Boiler and Pressure Vessel Code.

§ **193.2213 Concrete storage tanks.** Concrete storage tanks must be designed and constructed in accordance with Section 4-3 of NFPA-59A.

§ **193.2215 Thermal barriers.** Thermal barriers must be provided between piping and an outer shell from being exposed during normal operation to temperatures lower than its design temperature.

§ **193.2217 Support system.** (a) Saddles and legs must be designed in accordance with generally accepted structural engineering practices, taking into account loads during transportation, erection loads, and thermal loads.

(b) Storage tank stress concentrations from support systems must be minimized by distribution of loads using pads, load rings, or other means.

(c) For a storage tank with an inner container, support systems must be designed to—

(1) Minimize thermal stresses imparted to the inner container and outer shell from expansion and contraction; and

(2) Sustain the maximum applicable loading from shipping and operating conditions.

(d) LNG storage tanks with an air space beneath the tank bottom or its foundation must be designed to withstand without loss of functional or structural integrity, the forces caused by the ignition of a combustible vapor cloud in this space.

§ **193.2219 Internal piping.** Piping connected to an inner container that is located in the space between the inner container and outer shell must be designed for not less than the pressure rating of the inner container. The piping must contain expansion loops where necessary to protect against thermal and other secondary stresses created by operation of the tank. Bellows may not be used within the space between the inner container and outer shell.

§ **193.2221 Marking.** (a) Each operator shall install and maintain a name plate in an accessible place on each storage tank and mark it in accordance with the applicable code or standard incorporated by reference in §§ 193.2211 or 193.2213.

(b) Each penetration in a storage tank must be marked indicating the function of the penetration.

(c) Marking required by this section must not be obscured by frosting.

Design of Transfer Systems

§ **193.2223 General.** (a) Transfer systems must comply with the requirements of this subpart and other applicable requirements of this part.

(b) The design of transfer systems must provide for stress due to the frequency of thermal cycling and intermittent use to which the transfer system may be subjected.

(c) Slip type expansion joints are prohibited and packing-type joints may not be used in transfer systems for LNG or flammable refrigerants.

(d) A suitable means must be provided to precool the piping in a manner that prevents excessive stress prior to normal transfer of cold fluids.

(e) Stresses due to thermal and hydraulic shock in the piping system must be determined and accommodated by design to avoid damage to piping.

§ **193.2227 Backflow.** (a) Each transfer system must operate with a means to—

(1) Prevent backflow of liquid from a receiving container, tank car, or tank truck from causing a hazardous condition; and

(2) Maintain one-way flow where necessary for the integrity or safe operation of the LNG facility.

(b) The means provided under paragraph (a) (1) of this section must be located as close as practical to the point of connection of the transfer system and the receiving container, tank car, or tank truck.

§ **193.2229 Cargo transfer systems.** (a) Each cargo transfer system must have—

(1) A means of safely depressurizing and venting that system before disconnection;

(2) A means to provide for safe vapor displacement during transfer;

(3) Transfer piping, pumps, and compressers located or protected by suitable barriers so that they are safe from damage by tank car or tank truck movements;

(4) A signal light at each control location or remotely located pumps or compressors used for transfer which indicates whether the pump or compressor is off or in operation; and

(5) A means of communication between loading or unloading areas and other areas in which personnel are associated with the transfer operations.

(b) Hoses and arms for cargo transfer systems must be designed as follows—

(1) The design must accommodate operating pressures and temperatures encountered during the transfers;

(2) Hoses must have a bursting pressure of not less than five times the operating pressure.

(3) Arms must meet the requirements of ANSI B31.3.

(4) Adequate support must be provided, taking into account ice formation.

(5) Couplings must be designed for the frequency of any coupling or uncoupling.

§ 193.2231 Cargo transfer area. The transfer area of a cargo transfer system must be designed—

(a) To accommodate tank cars and tank trucks without excessive maneuvering; and

(b) To permit tank trucks to enter or exit the transfer area without backing.

§ 193.2233 Shutoff valves. (a) Shutoff valves on a transfer systems must be located—

(1) On each liquid supply line, or common line to multiple supply lines, to a storage tank, or to a cargo transfer system;

(2) On each vapor or liquid return line from multiple return lines, used in a cargo transfer system;

(3) At the connection of a transfer system with a pipeline subject to Part 192 of this chapter; and

(4) To provide for proper operation and maintenance of each transfer system.

(b) Transfer system shutoff valves that are designated for operation in the emergency procedures must be manually operable at the valve and power operable at the valve and at a remote location at least 50 feet from the valve.

Subpart D—Construction

§ 193.2301 Scope. This subpart prescribes requirements for the construction or installation of components.

§ 193.2303 Construction acceptance. No person may place in service any component until it passes all applicable inspections and tests prescribed by this subpart.

§ 193.2204 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 **Procedures.** (a) In performing construction, installation, inspection, or testing, an operator must follow written specifications, procedures, and drawings, as appropriate, that are consistent with this part, taking into account relevant mechanical, chemical, and thermal properties, component functions, and environmental effects that are involved.

(b) All procedures, including any field revisions, must be substantiated by testing or experience to produce a component that is reliable and complies with the design and installation requirements of this part.

§ 193.2307 **Inspection.** (a) All construction, installation, and testing activities must be inspected as frequently as necessary in accordance with a written plan to assure that—

(1) Activities are in compliance with all applicable requirements of this subpart; and

(2) Components comply with the applicable material, design, fabrication, installation, and construction requirements of this part.

(b) In addition to the requirements of paragraph (a) of this section, the construction of concrete storage tanks must be inspected in accordance with ACI-311-75.

(c) Each operator shall have a quality assurance inspection program to verify that components comply with their design specifications and drawings, including any field design changes, before they are placed in service.

§ 193.2309 **Inspection and testing methods** Except as otherwise provided by this subpart, each operator shall determine, commensurate with the hazard that would result from failure of the component concerned, the scope and nature of—

(a) Inspections and tests required by this subpart; and

(b) Inspection and testing procedures required by § 193.2305.

§ 193.2311 **Cleanup.** After construction or installation, as the case may be, all components must be cleaned to remove all detrimental contaminents which could cause a hazard during operation, including the following:

(a) All flux residues used in brazing or soldering must be removed from the joints and the base metal to prevent corrosive solutions from being formed.

(b) All solvent type cleaners must be tested to ensure that they will not damage equipment integrity or reliability.

(c) Incompatible chemicals must be removed.

(d) All contaminants must be captured and disposed of in a manner that does not reduce the effectiveness of corrosion protection and monitoring provided as required by this part.

§ 193.2313 Pipe welding. (a) Each operator shall provide the following for welding on pressurized piping for LNG and other hazardous fluids:

(1) Welding procedures and welders qualified in accordance with Section IX of the ASME Boiler and Pressure Vessel Code or API 1104, as applicable;

(2) When welding materials that are qualified by impact testing, welding procedures selected to minimize degradation of low temperature properties of the pipe material; and

(3) When welding attachments to pipe, procedures and techniques selected to minimize the danger of burn-throughs and stress intensification.

(b) Oxygen fuel gas welding is not permitted on flammable fluid piping with a service temperature below —20°C (—22°F).

(c) Marking materials for identifying welds on pipe must be compatible with the basic pipe material.

(d) Surfaces of components that are less than 6.35 mm (0.25 in.) thick may not be field die stamped.

(e) Where die stamping is permitted, any identification marks must be made with a die having blunt edges to minimize stress concentration.

§ 193.2315 Piping connections. (a) Piping more than 2 inches nominal diameter must be joined by welding, except that—

(1) Threaded or flanged connections may be used where necessary for special connections, including connections for material transitions, instrument connections, testing, and maintenance;

(2) Copper piping in nonflammable service may be joined by silver brazing; and

(3) Material transitions may be made by any joining technique proven reliable under § 193.2305 (b).

(b) If socket fittings are used, a clearance of 1.6 to 3.2 mm (0.063 to 0.126 in.) between the pipe end and the bottom of the socket recess must be provided and appropriate measurement reference marks made on the piping for the purpose of inspection.

(c) Threaded joints must be—

(1) Free of stress from external loading; and

(2) Seal welded, or sealed by other means which have been tested and proven reliable.

(d) Compression type couplings must meet the requirements of ANSI B31.3.

(e) Care shall be taken to ensure the tightness of all bolted connections. Spring washers or other such devices designed to compensate for the contraction and expansion of bolted connections during operating cycles shall be used where required.

(f) The selection of gasket material shall include the consideration of fire.

§ **193.2317 Retesting.** After testing required by this subpart is completed on a component to contain a hazardous fluid, the component must be retested whenever—

(a) Penetration welding other than tie-in welding is performed; or

(b) The structural integrity of the component is disturbed.

§ **193.2319 Strength tests.** (a) A strength test must be performed on each piping system and container to determine whether the component is capable of performing its design function, taking into account—

(1) The maximum allowable working pressure;

(2) The maximum weight of product which the component may contain or support;

(b) For piping, the test required by paragraph (a) of this section must include a pressure test conducted in accordance with Section 337 of ANSI B31.3, except that test pressures must be based on the design pressure. Carbon and low alloy steel piping must be pressure tested above their nil ductility transition temperature.

(c) All shells and internal parts of heat exchangers to which Section VIII. Division 1, or Division 2 of the ASME Boiler and Pressure Vessel Code, applies must be pressure tested, inspected, and stamped in accordance therewith.

§ **193.2221 Nondestructive tests.** (a) The following percentages of each day's circumferentially welded pipe joints for hazardous fluid piping, selected at random, must be nondestructively tested over the entire circumference to indicate any defects which could adversely affect the integrity of the weld or pipe:

Weld type	Cyogaric'	Other piping	Test method
Butt welds more than 2 inches in normal stress.	100	30	Radiographic or ultrasonic.
Butt welds 2 inches or less in nominal stress.	100	30	Radiographic, ultrasonic, liquid penetrate, or magnetic particle.
Filled and socket welds.	100	30	Liquid penetrant or magnetic particle.

(b) Evaluation of weld tests and repair of defects must be in accordance with the requirements of ANSI B31.3 or API 1104, as applicable.

(c) Where longitudinally or spiral welded pipe is used in transfer systems, 100 percent of the seam weld must be examined by radiographic or ultrasonic inspection.

(d) The butt welds in metal shells of storage tanks with internal design pressure of not more than 15 psig must be radiographically tested in accordance with Section 0.7.6. API 620. Appendix Q, except that for hydraulic load bearing shells with curved surfaces that are subject to cryogenic temperatures, 100 percent of both longitudinal (or meridional) and circumferential or (or latitudinal) welds must be radiographically tested.

(e) The butt welds in metal shells of storage tanks with internal design pressure above 15 psig must be radiographically tested in accordance with Section IX of the ASME Boiler and Pressure Vessel Code, except that for hydraulic load bearing shells with curved surfaces that are subject ot cryogenic temperatures, 100 percent of both longitudinal (or meridional) and circumferential (or latitudinal) welds must be radiographically tested.

§ **193.2323 Leak tests.** (a) Each container and piping system must be initially tested to assure that the component will contain the product for which it is designed without leakage.

(b) Shop fabricated containers and all flammable fluid piping must be leak tested to a minimum of design presure after installation but before placing it in service.

(c) For a storage tank with vacuum insulation, the inner container, outer shell, and all internal piping must be tested for vacuum leaks in accordance with an appropriate procedure.

§ **193.2326 Testing control systems.** Each control system must be tested before being placed in service to assure that it has been installed properly and will function as required by this part.

§ **193.2327 Storage tank tests.** (a) In addition to other applicable requirements of this subpart, storage tanks for cryogenic fluids with internal design pressures of not more than 15 psig must be tested in accordance with Sections Q8 and Q9 of API 620, Appendix Q, as applicable.

(b) Metal storage tanks for cryogenic fluids with internal design pressures above 15 psig must be tested in accordance with the applicable division of Section VIII of the ASME Boiler and Pressure Vessel Code.

(c) Reference measurements must be made with appropriate precise instruments to assure that the tank is gas tight and lateral and vertical movement of the storage tank does not exceed predetermined design tolerances.

§ **193.2329 Construction records.** For the service life of the component concerned, each operator shall retain appropriate records of the following:

(a) Specifications, procedures, and drawings prepared for compliance with § 193.2305; and

(b) Results of tests, inspections, and the quality assurance program required by this subpart.

Subpart E—Equipment

§ **193.2401 Scope.** This subpart prescribes requirements for the design, fabrication, and installation of vaporization equipment, liquifaction equipment, and control systems.

Vaporization Equipment

§ **193.2403 General.** Vaporizers must comply with the requirements of this subpart and the other applicable requirements of this part.

§ 193.2405 Vaporizer design. (a) Vaporizers must be designed and fabricated in accordance with applicable provisions of Section VIII. Division 1 of the ASME Boiler and Pressure Vessel Code.

(b) Each vaporizer must be designed for the maximum allowble working pressure at least equal to the maximum discharge pressure of the pump or pressurized container system supplying it, whichever is greater.

§ 193.2407 Operational control. (a) Vaporizers must be equipped with devices which monitor the inlet pressure of the LNG, the outlet temperature, and the pressure of the vaporized gas, and the inlet pressure of the heating medium fluids.

(b) Manifolded vaporizers must be equipped with:

(1) Two inlet valves in series to prevent LNG from entering an idle vaporizer; and

(2) A means to remove LNG or gas which accumulates between the valves.

§ 193.2409 Shutoff valves. (a) A shutoff valve must be located on transfer piping supplying LNG to a vaporizer. The shutoff valve must be located at a sufficient distance from the vaporizer to minimize potential for damage from explosion or fire at the vaporizer. If the vaporizer is installed in a building, the shutoff valve must be located outside the building.

(b) A shutoff valve must be located on each outlet of a vaporizer.

(c) For vaporizers designed to use a flammable intermediate fluid, a shutoff valve must be loacted on the inlet and outlet line of the intermediate fluid piping system where they will be operable during a controllable emergency involving the vaporizer.

§ 193.2411 Relief devices. The capacity of pressure relief devices required for vaporizers by § 193.2429 is governed by the following:

(a) For heated vaporizers, the capacity must be at least 110 percent of rated natural gas flow capacity without allowing the pressure to rise more than 10 percent above the vaporizer's maximum allowable working pressure.

(b) For ambient vaporizers, the capacity must be at least 150 percent of rated natural gas flow capacity without allowing the pressure to rise more than 10 percent above the vaporizer's maximum allowable working pressure.

§ 193.2413 Combustion air intakers. (a) Combustion air intakes to vaporizers must be equipped with sensing devices to detect the induction of a flammable vapor.

(b) If a heated vaporizer or vaporizer heater is located in a building, the combustion air intake must be located outside the building.

Liquefaction Equipment

§ 193.2415 General. Liquefaction equipment must comply with the requirements of this subpart and the other applicable requirements of this part.

§ **193.2417 Control of incoming gas.** A shutoff valve must be located on piping delivering natural gas to each liquefaction system.

§ **193.2419 Backflow.** Each multiple parallel piping system connected to liquefaction equipment must have devices to prevent backflow from causing a hazardous condition.

§ **193.2421 Cold boxes.** (a) Each cold box in a luiquefaction system must be equipped with a means of monitoring or detecting, as appropriate, the concentration of natural gas in the insulation space.

(b) If the insulation space in a cold box is designed to operate with a gas rich atmosphere, additional natural gas must be introduced when the concentration of gas falls to 30 percent.

(c) If the insulation space of a cold box is designed to operate with a gas free atmosphere, additional air or inert gas, as appropriate, must be introduced when the concentration of gas is 25 percent of the lower flammable limit.

§ **193.2423 Air in gas.** Where incoming gas to liquefaction equipment contains air, each operator shall provide a means of preventing a flammable mixture from occurring under any operating condition.

Control Systems

§ **193.2427 General.** (a) Control systems must comply with the requirements of this subpart and other applicable requirements of this part.

(b) Each control system must be capable of performing its design function under normal operating conditions.

(c) Control systems must be designed and installed in a manner to permit maintenance, including inspection or testing, in accordance with this part.

(d) Local, remote, and redundant signal lines installed for control systems that can affect the operation of a component that does not fail safe must be routed separately or in separate underground conduits installed in accordance with NFPA-70.

§ **193.2429 Relief devices.** (a) Each component containing a hazardous fluid must be equipped with a system of automatic relief devices which will release the contained fluid at a rate sufficient to prevent pressures from exceeding 110 percent of the maximum allowable working pressure. In establishing relief capacity, each operator shall consider trapping of fluid between valves; the maximum rates of boiloff and expansion of fluid which may occur during normal operation, particularly cooldown; and controllable emergencies.

(b) A component in which internal vacuum conditions can occur must be equipped with a system of relief devices or other control system to prevent development in the component of a vacuum that might create a hazardous condition. Introduction of gas into a componant must not create a flammable mixture within the component.

(c) In addition to the control system required by paragraphs (a) and (b) of this section—

(1) Each LNG Storage tank must be equipped with relief devices to assure that design pressure and vacuum relief capacity is available during maintenance of the system; and

(2) A manual means must be provided to relieve pressure and vacuum in an emergency.

(d) Relief devices must be installed in a manner to minimize the possibility that release of fliud could—

(1) Cause an emergency; or

(2) Worsen a controllable emergency.

(e) The means for adjusting the setpoint pressure of all adjustable relief devices must be sealed.

(f) Relief devices which are installed to limit minimum or maximum pressure may not be used to handle boiloff and flash gases during normal operation.

§ **193.2431 Vents.** (a) Hazardous fluids may not be relieved into the atmosphere of a building or other confined space.

(b) Boiloff vents for hazardous fluids may not draw in air during operation.

(c) Venting of natural gas/vapor under operational control which could produce a hazardous gas atmosphere must be directed to a flare stack or heat exchanger in order to raise its temperature to achieve positive buoyancy and safe venting.

§ **193.2433 Sensing devices.** Each operator shall determine the appropriate location for and install sensing devices as necessary to—

(1) Monitor the operation of components to detect a malfunction which could cause a hazardous condition if pemitted to continue; and

(2) Detect the presence of fire or combustible gas in areas determined in accordance with Section 500-4 of NFPA 70 to have a potential for the presence of flammable fluids.

(b) Buildings in which potentially hazardous quantities of flammable fluids are used or handled must be continuously monitored by gas sensing devices set to activate audible and visual alarms in the building and at the control center when the concentration of the fluid in air is not more than 25 percent of the lower flammable limit.

§ **193.2435 Warning devices.** Each operator shall install warning devices in the control center to warn of hazardous conditions detected by all sensing devices required by this part. Warnings must be given both audibly and visibly and must be designed to gain the attention of personnel. Warnings must indicate the location and nature of the existing or potential hazard.

§ **193.2437 Pump and compressor control.** (a) Each pump and compressor for hazardous fluids must be equipped with—

(1) A control system, operable locally and remotely, to shut down the pump or compressor in a controllable emergency;

(2) A signal light at the pump or compressor and the remote control location which indicates whether the pump or compressor is in operation or off;

(3) Adequate valving to ensure that the pump or compressor can be isolated for maintenance; and

(4) A check valve on each discharge line where pumps or compressors operate in parallel.

(b) Pumps or compressors in a cargo transfer system must have shutdown controls at the loading or unloading area and at the pump or compressor site.

§ 193.2439 Emergency shutdown control systems. (a) Each transfer system, vaporizer, liquefaction system, and storage system tank must be equipped with an emergency shutdown control system. The control must automatically actuate the shutdown of the component (providing pressure relief as necessary) when any of the following occurs:

(1) Temperatures of the component exceed the limits determined under § 193.2105;

(2) Pressure outside the limits of the maximum and minimum design pressure;

(3) Liquid in receiving vessel reaches the design maximum liquid level;

(4) Gas concentrations in the area of the component exceed 40 percent of the lower flammable limit;

(5) A sudden excessive pressure change or other condition indicating a potentially dangerous condition; and

(6) Presence of fire in area of component.

(b) For cargo transfer systems where all transfer operations are continuously manned and visually supervised by qualified personnel, actuation of the emergency shutdown control system may be manual after devices warn of the events listed in paragraph (a) of this section.

(c) Except for components that operate unattended and are remote from the control center, a reasonable delay may be programmed in emergency shutdown control systems required by this section between warning and automated shutdown to provide for manual response.

(d) Each LNG plant must have a shutdown control system to shut down all operations of the plant safely. The system must be operable at—

(1) The control center; and

(2) In the case of a plant where LNG facilities other than the control center are designed to operate unattended at the site of these facilities.

§ 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 Full-safe control.** Control systems for components must have a fail-safe design. A safe condition must be maintained until personnel take appropriate action either to reactivate the component served or to prevent a hazard from occurring.

§ **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 auxilliary 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; and

(2) Fuel supply must be protected from hazards.

Subpart F—Operations

§ **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 satisfactory 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 liquefactions, maintaining temperatures, pressures, pressured differentials and flow rates as applicable, within their design limits for:

(1) Boilers:

(2) Turbines and other prime movers:

(3) Pumps, compressors, and expanders;

(4) Purification and regeneration equipment, and

(5) Equipment within cold boxes.

(g) Cooldown of components according to the requirements of § 193.2505; and

(h) Compliance with § 193.2005 (b).

§ **193.2505 Cooldown.** (a) The cooldown of each system of components that is subjected to cryogenic temperatures must be limited to a rate and distribution pattern that keeps thermal stresses within design limits during the cooldown period, paying particular attention to the performance of expansion and contraction devices.

(b) After cooldown stabilization is reached, cryogenic piping systems must be checked for leaks in areas of flanges, valves, and seals.

§ **193.2507 Monitoring operations.** Each component in operation or building determined under § 193.2005 (a) (2) in which a hazard to persons or property could exist must be monitored to detect fire or any malfunctions or flammable fluid which could cause a hazardous condition. Monituring must be accomplished by watching or listening from an attended control center for warning alarms, such as gas, temperature, pressure, vacuum, and flow alarms, or by conducting an inspection or test at intervals specified in the operaing procedures.

§ **193.2509 Emergency procedures.** (a) Each operator shall determine the types and places of emergencies other than fires that may reasonably be expected to occur at an LNG plant due to operating malfunctions, structural collapse, personnel error, forces of nature, and activities adjacent to the plant.

(b) To adequately handle each type of emergency identified under paragraph (a) of this section and each fire emergency identified under § 193.2817 (a), each operator shall follow 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 pro-

tect the public in the event of an emergency, including catastrophic failure of an LNG storage tank.

(4) Cooperating 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.

§ **192.2513 Transfer procedures.** (a) Each transfer of LNG or other hazardous fluid must be conducted in accordance with one or more manuals of written procedures to provide for safe transfers.

(b) The transfer procedures must include provisions for personnel to:

(1) Before transfer, verify that the transfer system is ready for use, with connections and controls in proper positions, including if the system could contain a combustible mixture, verifying that it has been adequately purged in accordance with a procedure which meets the requirements of AGA. "Purging Principles and Practice."

(2) Before transfer, verify that each receiving container or tank vehicle does not contain any substance that would be incompatible with the incoming fluid and that there is sufficient capacity available to receive the amount of fluid to be transferred:

(3) Before transfer, verify the maximum filling volume of each receiving container or tank vehicle to ensure that expansion of the incoming fluid due to warming will not result in overfilling or overpressure;

(4) When making bulk transfer of LNG into a partially filled (excluding cooldown heel) container, determine any differences in temperature or specific graviey between the LNG being transferred and the LNG already in the container and, if necessary, provide a means to prevent rollover due to stratification.

(5) Verify that the transfer operations are proceeding within design conditions and that overpressure or overfilling does not occur by monitoring applicable flow rates, liquid levels, and vapor returns.

(6) Manually terminate the flow before overfilling or overpressure occurs; and

(7) Deactivate cargo transfer systems in a safe manner by depressurizing, venting, and disconnecting lines and conducting any other appropriate operations.

(c) In addition to the requirements of paragraph (b) of this section, the procedures for cargo transfer must be located at the transfer area and include provisions for personnel to:

(1) Be in constant attendance during all cargo transfer operations;

(2) Prohibit the backing of tank trucks in the transfer area, except when a person is positioned at the rear of the truck giving instructions to the driver;

(3) Before transfer, verify that—

(i) Each tank car or tank truck complies with applicable regulations governing its use;

(ii) All transfer hoses have been visually inspected for damage and defects;

(iii) Each tank truck is properly immobilized with chock wheels, and electrically grounded; and

(iv) Each tank truck engine is shut off unless it is requiured for transfer operations;

(4) Prevent a tank truck engine that is off during transfer operations from being restarted untill the transfer lines have been disconnected and any released vapors have dissipated;

(5) Prevent loading LNG into a tank car or tank truck that is not in exclusive LNG service or that does not contain a positive pressure if it is in exclusive LNG service, until after the oxygen content in the tank is tested and if it exceeds 2 percent by volume, purged in accordance with a procedure that meets the requirements of AGA "Purging Principles and Practice."

(6) Verify that all transfer lines have been disconnected and equipment cleared before the tank car or tank truck is moved from the transfer position; and

(7) Verify that transfers into a pipeline system will not exceed the pressure or temperature limits of the system.

§ **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 reoccurrence of the incident.

(c) If the Director or relevant state agency under section 5 of the Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. 1674) 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, no component involved in the incident may be moved from its location or otherwise altered until the investigation is complete or the investigating agency otherwise provides. Where components must be moved for operational or safety reasons, they must not be removed from the plant site and must be maintained intact to the extent practicable until the investigation is complete or the investigating agency otherwise provides.

§ **193.2517 Purging.** When necessary for safety, components that could accumulate significant amounts of combustible mixtures must be purged in accordance with a procedure which meets the provisions of the AGA "Purging Principles and Practice" after being taken out of service and before being returned to service.

§ **193.2519 Communication systems.** (a) Each LNG plant must have a primary communication system that provides for verbal communications between all operating personnel at their work stations in the LNG plant.

(b) Each LNG plant in excess of 70,000 gallons storage capacity must have an emergency communication system that provides for verbal communications between all persons and locations necessary for the orderly shutdown of operating equipment and the operation of safety equipment in time of emergency. The emergency communication system must be independent of and physically separated from the primary communication system and the security communication system under § 193.2909.

(c) Each communication system required by this part must have an auxiliary source of power, except sound-powered equipment.

§ **193.2521 Operating records.** Each operator shall maintain a record of the results of each inspection, test, and investigation required by this subpart. Such records must be kept for a period of not less than 5 years.

Subpart G—Maintance

§ **193.2601 Scope.** This subpart prescribes requirements for maintaining components at LNG plants.

§ **193.2603 General.** (a) Each component in service, including its support system, must be maintained in a condition that is compatible with its operational or safety purpose by repair, replacement, or other means.

(b) An operator may not place, return, or continue in service any component which is not maintained in accordance with this subpart.

(c) Each component taken out of service must be identified in the records kept under § 193.2639.

(d) If a safety device is taken out of service for maintenance, the component being served by the device must be taken out of service unless the same safety function is provided by an alternate means.

(e) If the inadvertent operations of a component taken out of service could cause a hazardous condition, that component must have a tag attached to the controls bearing the words "do not operate" or words of comparable meaning.

§ **193.2606 Maintenance procedures.** 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.

(b) Each operator shall follow one or more manuals of written procedures for the maintenance of each component, including any required corrosion control. The procedures must include—

(1) The details of the inspections or tests determined under paragraph (a) of this section and their frequency of performance; and

(2) A description of other actions necessary to maintain the LNG plant in accordance with the requirements of this subpart and § 193.2805.

§ **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.

(c) Control systems in service, but not normally in operation (such as relief valves and automatic shutdown devices), must be inspected and tested once each calendar year, but with intervals 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 refgrigerant transfer systems must be—

(a) Tested more 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 or 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) Componants whose integrity or reliability could be adversely affected by corosion must be either—

(1) Protected from corrosion in accordance with §§ 193.2627 thru 193.2635, as applicable; or

(2) Inspected and replaced under a program of scheduled maiintenance 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 earlier.

(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 miinimize 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 data and type of each maintenance activity performed on each component to meet the requirements of this subpart, including periodic tests and inspections, 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.

Subpart I—Fire Protection

§ **193.2801 Scope.** This subpart prescribes requirements for fire prevention and fire control at LNG plants other than waterfront LNG plants.

§ **193.2803 General.** Each operator shall use sound fire protection engineering principles to minimize the occurrence and consequences of fire.

§ **193.2805 Fire prevention plan.** (a) Each operator shall determine—

(1) Those potential sources of ignition located inside and adjacent to the LNG plant which could cause fires that affect the safety of the plant; and

(2) These areas, as described in Section 500—4 of MFPA-70, where the potential exists for the presence of flammable fluids in an LNG plant. Determinations made under this paragraph must be kept current.

(b) With respect to areas determined under paragraph (a) (2) of this section, each operator shall include in the operating and maintenance procedures under § 193.2503 and § 193.2605, as appropriate, steps necessary to minimize—

(1) The leakage or release of flammable fluids; and

(2) The possibility of flammable fluids being ignited by sources identified under paragraph (a) (1) of this section.

§ **193.2907 Smoking.** (a) (1) Smoking is prohibited at an LNG plant in areas identified under § 193.2805 (a) (2).

(2) Smoking is permitted only in such locations that the operator designates as a smoking area.

(b) Signs marked with the words "smoking permitted" must be displayed in prominent places in each smoking area designated under paragraph (a) of this section.

(c) Signs marked with the words "NO SMOKING" must be displayed in prominent places in areas where smoking is prohibited.

§ **193.2809 Open fires.** (a) No open fires are permitted at an LNG plant, except at flare stacks and at times and places designated by the operator.

(b) Whenever an open fire is designated, there must be at the site of the fire—

(1) Trained fire fighting personnel; and

(2) Fire control equipment which has the capability of extinguishing the fire.

(c) The fire fighting personnel and equipment must remain at the fire site until the fire is extinguished and there is no possibility of reignition.

§ **193.2811 Hotwork.** Welding, flame cutting, and similar operations are prohibited, except at times and places that the operator designates in writing as safe and when constantly supervised in accordance with NFPA-51B.

§ 193.2813 **Storage of flammable fluids.** Flammable fluids may not be stored in areas where ignition sources are present, unless stored in accordance with the requirements of Chapter 4 of NFPA 30.

§ 193.2815 **Motorized equipment.** Use of motor vehicles and other motorized equipment which constitute potential ignition sources is prohibited in an impounding space, in areas within 15 m (49.2 ft) of a storage tank, and in areas within 15 m (49.2 ft) of processing equipment containing a flammable fluid except—

(a) At times the operator designates in writing as safe; and

(b) When the motorized equipment is constantly attended.

§ 193.2817 **Fire equipment.** (a) Each operator shall determine; (1) the types and sizes of fires that may reasonably be expected to occur within and adjacent to each LNG plant that could affect the safety of components; and (2) The foreseeable consequences of these fires, including the failure of components or buildings due to heat exposure.

(b) Each operator shall provide and maintain fire control equipment and supplies in accordance with the applicable requirements of NFPA 59A to protect or cool components that could fail due to heat exposure from fires determined under paragraph (a) of this section and either worsen an emergency or endanger persons or property located outside the plant. Protection or cooling must be provided for as long as the heat exposure exists. The fire control equipment and supplies must include the following;

(1) Portable fire extinguishers suitable for types of fires identified under paragraph (a) of this section; and

(2) If the total inventory of LNG is 265 m^3 (70,000 gal.) or more, a water supply and associated delivery system.

(c) Each operator shall determine the type, size, quantity and location of the fire control equipment and supplies required under paragraph (b) of this section.

(d) Each operator shall provide each facility person who may be endangered by exposure to fire or the products of conbustion in performing fire control duties protective clothing and equipment, including, if necessary, a self-contained breathing apparatus.

(e) Portable fire control equipment protective clothing and equipment for personnel use controls for fixed fire control equipment, and fire control supplies must be conspicuously located, marked for easy recognition, and readily available for use.

(f) Fire control equipment must have operating instructions. Instructions must be attached to portable equipment and placed at the location of controls for fixed equipment.

§ 193.2819 **Gas detection.** (a) All areas determined under § 193.2805 (a) (2) in which a hazard to persons or property could exist must be continuously monitored for the presence of flammable gases and vapors with fixed flammable gas detection systems provided and maintained according to the applicable requirements of NFPA 59A.

(b) Each fixed flammable gas detection system must be provided with audible and visible alarms located at an attended control room or control station, and an audible alarm in the area of gas detection.

(c) Flammable gas detection alarms must be set to activate at not more than 25 percent of the lower flammable limit of the gas or vapor being monitored.

(d) Gas detection systems must be installed as that they can be readily tested as required by NFPA 59A.

(e) A minimum of two portable flammable gas detectors capable of measuring the lower flammable limit must be available at the LNG plant for use at all times.

(f) All enclosed buildings located on an LNG plant must be continuously monitored for the presence of flammable gases and vapors with a fixed flammable gas detection system that provides a viable or audible alarm outside the enclosed building. The systems must be provided and maintained according to the applicable requirements of NFPA 59A.

§ 193.2821 Fire detection. (a) Fire detectors that continuously monitor for the presence of either flame, heat, or products of combustion must be provided in all areas determined under § 193.2805 (a) (2) in which a hazard to persons or property could exist and in all other areas that are used for the storage of flammable or combustible material.

(b) Each fire detection systems must be provided with audible and visible alarms located at an attended control room or central station, and an audible alarm in the area of fire detection. The systems must be provided and maintained according to the applicable requirements of NFPA 59A.

Subpart J—Security

§ 193.2901 Scope. This subpart prescribes requirements for security at LNG plants other than waterfront LNG plants.

§ 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, where 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 identifications 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) Protective enclosures must be fences or walls constructed as follows:

(1) Fences must be chainlink security fences constructed of No. 11 American wire gauge or heavier metal wire.

(2) Walls must be vertical and constructed of stone, brick, cinder block, concrete, steel or comparable materials.

(3) Protective enclosures must be topped by three or more strands of barbed wire or similar materials on brackets angled outward between 30" and 45" from the vertical, with a height of at least 2.4m (8 ft.) including approximately one foot of barbed topping.

(4) 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.

(c) Paragraphs (b) (1) thru (b) (3) of the section do not apply to protective enclosures constructed before October 23, 1980.

(1) Are made of noncombustible materials:

(2) Are at least 2.1m (7 ft.) in height including approximately one foot of barbed or similar topping; and

(3) Have served to protect the LNG plant without having been breached during their history of service.

§ **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.

§ **192.2911 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.) 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 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 dintance of 39m (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.

Subpart H—Personnel Qualification and Training

§ **193.2701 Scope.** This subpart prescribes requirements for personnel qualifications and training.

§ **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.

§ **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.

§ **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—

(1) All permanent maintenance, operating, and supervisory personnel—

(i) 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;

(ii) About the potential hazards involved in operating and maintenance activities; and

(iii) To carry out aspects of the operating and maintenance procedures under §§ 193.2503 and 193.2605 that relate to their assigned functions; and

(2) All personnel—

(i) To carry out the emergency procedures under § 193.2509 that relate to their assigned functions; and

(ii) To give first-aid; and

(3) All operating and appropriate supervisory personnel—

(i) To understand detailed instruction on the facility operations, including controls, functions, and operating procedures; and

(ii) To understand the LNG transfer procedures provided under § 193.2513.

(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.

§ **193.2715 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 having security duties 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.

Appendix A to Part 193—Incorporation by Reference

I. List of Organizations and Addresses

A. American Concrete Institute (ACI), P.O. Box 19150, Redford Station, Detroit, Michigan 48219.

B. American Gas Association (AGA). 1515 Wilson Boulevard, Arlington, Virginia 22209.

C. American National Standards Institute (ANSI), 1430 Broadway, New York, New York 10018.

D. American Petroleum Institute (API), 2101 L. Street, NW., Washington, D.C. 20037.

E. American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, New York 10017.

F. National Fire Protection Association (NFPA), 470 Atlantic Avenue, Boston, Massachusetts 02210.

G. International Conference of Building Officials, 5360 South Workman Hill Road, Whittier, California 90601.

II. Documents Incorporated by Reference

A. American Concrete Institute (ACI)

1. ACI Standard 311-75— Recommended Practice for Concrete Inspection, (1975 edition).

B. American Gas Association (AGA)

1. Evaluation of LNG Vapor control Methods. (October 1974 edition).

2. Purging Principles and Practice (1975 edition).

C. American National Standards Institute (ANSI)

1. ANSI A 58.1 Building Code Requirements for Minimum Design Loads in Buildings and Other Structures.

D. American Petroleum Institute (API)

1. API 620-Recommended Rules for Design and Construction of Large, Welded, Law Pressure Storage Tanks (6th edition, Dec. 1978)

2. API 1104 Standard for Welding Pipelines and Related Facilities (15th edition, 1980)

3. API 6D Specifications for Pipeline Valves (17 edition, 1977).

E. American Society of Mechanical Engineers (ASME)

1. ANSI B31.32 Chemical and Plant Petroleum Refinery Piping (1976 edition).

2. ASME Boiler and Pressure Vessel Code, Section 1 Power Boilers (1977 edition).

3. ASME Boiler and Pressure Vessel Code, Section 8 Division 1 (1977 edition).

4. ASME Boiler and Pressure Vessel Code, Section 8 Division 2, Alternative Rules (1977 edition).

5. ASME Boiler and Pressure Vessel Code, Section 9 Welding and Brazing Qualifications (1977 edition).

6. ASME Boiler and Pressure Vessel Code, Section 4 Heating Boilers.

7. ANSI B31.5 Refrigeration Piping (1974 edition).

8. ANSI B31.8 Gas Transmission and Distribution Piping Systems (1975 edition).

F. International Conference of Building Officials

1. UBC, Uniform Building Code (1979 edition).

G. National Fire Protection Association (NFPA)

1. NFPA No. 37 Stationary Combustion Engine and Gas Turbines (1979 edition).

2. NFPA No. 59A. Storage and Handling of LNG (1972 edition for § 193.2005 (c), otherwise 1979 edition).

3. NFPA No. 70 National Electric Code (1978 edition).

4. NFPA No. 30. Flammable Liquids (1981 edition).

5. NFPA No. 51 B. Cutting and Welding Processes (1977 edition).

History: Cr. Register, May, 1972, No. 197, eff. 6-1-72; cr. 192.12, 192.379, appendix A-II F 4; am. 192.201 (a), 192.625 (g) (1), 192.717 (b), 192.727, Register, February, 1973, No. 206, eff. 3-1-73; am. PSC 192.457 (d), PSC 192.613 (c) (1), Register, June, 1974, No. 222, eff. 7-1-74; am. 192.3, 192.55 (a) (2) and (b) (2), 192.65, 192.197 (a), 192.625 (g) (1), appendix A-I, B, and II A, 1., 2., 3., and 5., appendix B, I, cr. appendix B, III, Register, December, 1974, No. 228, eff. 1-1-75; am. 192.59 (a) (1), (b) (1) and cr. (c), am. 192.65 (a), 192.225 (a), 192.227 (a) (2), 192.229 (c), 192.241 (c), 192.625 (a) and (b), 192.625 (g) (1), 192.705 (a) and (b), r. 192.705 (c), cr. 192.706, am. 192.707, appendix A II and appendix B I, Register, March, 1976, No. 243, eff. 4-1-76; revised, Register, April, 1977, No. 256, eff. 5-1-77; am. 192.13 (2), 192.313 (a) (4), 192.455 (f), 192.619 (a) (2) (ii), 192.707 (d) (1) and (e) (2) (i), cr. 192.14, 192.452 and 192.455 (f), Register, May, 1978, No. 269, eff. 6-1-78; cr. 192.283, 192.285, 192.287 and part 193., am. (1), 192.121, PSC 192.375, PSC 192.727, Appendix A, IIA and IIB,

Appendix B, I, 192.281, 192.465 (a), 192.711 (b) and 192.713, r. 192.12, Register, December, 1981, No. 312, eff. 1-1-82.