

(1) The wearability and effectiveness of the inflatable PFD must be better than currently approved PFD's.

(2) The reliability of the inflatable PFD must not be significantly reduced as compared to currently approved PFD's and,

(3) The devices must be affordable so significant numbers of boaters will buy them. The Coast Guard will carefully weigh the necessary trade-offs among these conflicting requirements.

There are numerous detailed technical alternatives in specifying the minimum performance required of inflatable PFDs. The Coast Guard will discuss as many of these alternatives as possible and resolve them through the consensus standards making process. Those remaining unresolved will be presented in the NPRM on recreational inflatable PFD's for public comment.

Factors To Be Considered

In addition to providing notice of the consensus standards making process, this advance notice of proposed rulemaking is issued to solicit comment on certain broad, initial issues relating to the proper approach and recommended content of the standards. The Coast Guard requests public as well as industry views and data specifically relating to the following issues and possible requirements for inflatable PFD's.

1. An inflation system that indicates its condition appears to be the best approach to overcome the major reliability problem with inflatables. Two independent studies have shown that recreational boaters do not always maintain inflatable PFDs in an overall serviceable condition. Thus, something must be done to increase an inflatable PFD's reliability. An indicating device will assist users in keeping the devices in a serviceable condition. Such a feature should alleviate the great majority of maintenance problems reported in the recently completed study by allowing the inflation system to be "self inspecting." The indicating device should be a single, obvious feature of the inflation system, that will allow the boater to be reasonably sure the PFD is ready to function/perform when used or be able to identify if the device requires servicing or rearming.

2. Approval of several types of inflatable PFD's will provide more choices suitable for a variety of different boating activities. Devices to be approved under this rule change would probably be labeled as Type I or II PFDs in addition to Type V. A Type V device is intended for use in specific activities, on limited types of vessels, or under

specific use conditions as indicated on the PFD label.

3. The "approved only when worn" approach was developed to ensure that hybrid PFDs would be maintained. However, this requirement may have been a factor in the hybrid's lack of acceptance. For devices equipped with a positive means to identify if the inflation assembly has been discharged, the Coast Guard may not impose the condition that the device be "required to be worn" to meet the carriage requirements on recreational boats. This would remove the problem of having to carry two devices if the user were concerned that the device could or would not be worn at all times. This will result in cost savings to some boaters who prefer to use inflatable PFDs, but who must at present also carry an approved, inherently buoyant device to meet carriage requirements. The approval condition "required to be worn" or "approved only when worn" might be required on inflatable devices that do not have a means of indicating whether the inflation assembly has been discharged. These devices would be labeled as a Type V PFD. Such a condition on approval would likely increase the chance that an inflatable will receive the attention required to ensure it is maintained in a serviceable condition. This alternative will be further evaluated during the rulemaking process.

4. Removing the requirement for two chambers on all but the highest performing devices (Type I's) will reduce the cost of devices intended for most of the recreational sector.

5. Making inflatable PFDs "associated equipment" in 33 CFR part 179 under 46 U.S.C. 4310 would make the retailer/manufacturer subject to the defect notification requirements of that statute. This would provide better accountability and a positive means to identify reliability problems which may arise as a result of approval of a potentially less reliable device. Accordingly, the retailer or manufacturer (if manufacturer sells directly to the consumer) might be required to generate records listing consumers who purchased the inflatable PFD in the event there is a problem with the device, so the consumer can be notified of the defect and be given a means to correct it.

6. Further defining "serviceable" in the carriage requirements as requiring inflatables to have a properly armed inflation mechanism, would encourage the development of devices meeting the Coast Guard's standards for inflation mechanisms that have good human engineering characteristics such as ease

of use, ease of maintenance, and positive feedback, since professional servicing will not be used. Adding this condition for an inflatable to be considered "serviceable" appears essential to the successful use of inflatable PFD's.

7. Additionally, the Coast Guard requests views and data relating to the following specific issues for inflatable PFD's.

(A) The restrictions that should be placed on the use of inflatable PFD's by non-swimmers and children;

(B) The feasibility of requiring an automatic inflation mechanism for non-swimmers and children or prohibiting the use of inflatables altogether for people in these categories;

(C) The average boater's ability to determine if an inflatable PFD is in a serviceable condition if it has a "self inspecting" inflation system;

(D) Whether inflatable PFD's are too complicated for some people to operate in an emergency situation;

(E) The price of an inflatable PFD at which the average boater will purchase the device;

(F) The service life that should be expected of inflatable PFDs.

8. Other measures that might be considered but are presently not envisioned for this project include:

(A) Coast Guard requirement for professional servicing at "approved" servicing facilities. Professional servicing is expensive and administering approval of such facilities is a very large task. Additionally, the studies show that each time an inflatable is used there is the potential for it either to not be rearmed or to be rearmed improperly. Servicing by the manufacturer, dealer, or their agents may be beneficial after some long period of use, such as 5 years, but will not be necessary with "self inspecting" inflation systems.

(B) A system of accountability for the servicing facilities would be considered, if it would not be too cumbersome to administer.

Public comments are requested on the above issues as well as any issue related to the subject matter of this advance notice of proposed rulemaking.

Comments are strongly encouraged on the relative strengths and/or weaknesses of each item discussed. Suggestions for other alternatives are also highly encouraged.

Dated: October 14, 1993.

R.C. North,

Captain, U.S. Coast Guard, Acting Chief,
Office of Marine Safety, Security and
Environmental Protection.

[FR Doc. 93-27570 Filed 11-8-93; 8:45 am]

BILLING CODE 4910-14-M

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 93-28, RM-8172, RM-8299]

Radio Broadcasting Services; Colonial Heights, TN

AGENCY: Federal Communications Commission.

ACTION: Proposed rule; order to show cause.

SUMMARY: This document directs WFSM, Inc., and Franklin Communications, Inc., respective licensees of Station WCTU-FM, Channel 231A, Tazewell, Tennessee, and Station WMXK-FM, Channel 240A, Morristown, Tennessee, to show cause why their licenses should not be modified to specify operation on Channel 290A and 231A accordingly, instead of the present Channel 231A and Channel 240A. This action would allow Murray Communications, permittee of Channel 290A, Colonial Heights, Tennessee, to upgrade its facility to Channel 240C2 or, alternatively, to Channel 240C3. The coordinates for Channel 290A at Tazewell, Tennessee, are 36-27-32 and 83-35-07. The coordinates for Channel 231A at Morristown, Tennessee, are 36-13-40 and 83-14-58. The coordinates for Channel 240C2 at Colonial Heights, Tennessee, are 36-35-35 and 82-37-16. The coordinates for Channel 240C3 at Colonial Heights are 36-31-36 and 82-35-14. This Order does not afford additional opportunity either to comment on the merits of the conflicting proposal or for the acceptance of additional counterproposals.

DATES: Comments must be filed on or before December 27, 1993.

ADDRESSES: Federal Communications Commission, Washington, DC 20554. In addition to filing comments with the FCC, interested parties should serve the petitioner, or its counsel or consultant, as follows: Timothy K. Brady, Esq., P.O. Box 986, Brentwood, Tennessee 37027-0986, Counsel for Murray Communication.

FOR FURTHER INFORMATION CONTACT: Pamela Blumenthal, Mass Media Bureau, (202) 634-6530.

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's Order to Show Cause, MM Docket No. 93-28, adopted October 18, 1993, and released November 2, 1993. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC's Reference

Center (room 239), 1919 M Street NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractor, ITS, Inc., (202) 857-3800, 2100 M Street NW, suite 140, Washington, DC 20037.

Provisions of the Regulatory Flexibility Act of 1980 do not apply to this proceeding.

Members of the public should not that from the time a Notice of Proposed Rule Making is issued until the matter is no longer subject to Commission consideration or court review, all *ex parte* contacts are prohibited in Commission proceedings, such as this one, which involve channel allotments. See 47 CFR 1.1204(b) for rules governing permissible *ex parte* contacts.

For information regarding proper filing procedures for comments, see 47 CFR 1.415 and 1.420.

List of Subject in 47 CFR Part 73

Radio broadcasting.

Federal Communications Commission.

Victoria M. McCauley,

Assistant Chief, Allocations Branch, Policy and Rules Division, Mass Media Bureau.

[FR Doc. 93-27451 Filed 11-8-93; 8:45 am]

BILLING CODE 6712-01-M

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 192

[Docket No. PS-124; Notice 2]

RIN 2137-AC25

Regulatory Review: Gas Pipeline Safety Standards; NAPS Report on Recommendations for Revision of Gas Pipeline Safety Standards

AGENCY: Research and Special Programs Administration (RSPA), DOT.

ACTION: Notice of request for information.

SUMMARY: This document invites public comment on rulemaking proposals from the National Association of Pipeline Safety Representatives (NAPSR) for the safety of natural and other gas pipelines. The proposals result from a study NAPSR conducted, at the request of RSPA, of pipeline safety regulations which they considered unclear or difficult to enforce. Comments on the NAPSR study will assist RSPA in developing a position on the NAPSR recommendations.

DATES: Interested persons are invited to submit comments by January 10, 1994.

ADDRESSES: Written comments must be submitted in duplicate and mailed or hand-delivered to the Dockets Unit, room 8421, Research and Special Programs Administration, U.S. Department of Transportation, 400 Seventh Street SW., Washington, DC 20590-0001. Identify the docket and notice number stated in the heading of this notice. Comments will become part of this docket and will be available for inspection or copying in room 8421 between 8:30 a.m. and 4:30 p.m. each business day.

FOR FURTHER INFORMATION CONTACT: Christina M. Sames, (202) 366-4561, regarding the content of this document, or the Dockets Unit, (202) 366-5046, regarding copies of this document or other material in the docket.

SUPPLEMENTARY INFORMATION:

Related Document

On August 31, 1992, RSPA published a notice of proposed rulemaking (NPRM) (Docket PS-124, 57 FR 39572), titled "Regulatory Review: Gas Pipeline Safety Standards." This NPRM proposed 38 amendments to 49 CFR part 192 to provide clarity, to eliminate unnecessary or overly burdensome requirements, and to foster economic growth. The proposed amendments resulted from the regulatory review RSPA carried out in response to a Presidential directive issued January 28, 1992. Several of NAPSR's proposals address some of the same sections or provisions as those raised in the NPRM. Comments to these sections will be included in Docket PS-124 and will be taken into account during the development of the final rule.

Background Information

NAPSR is a non-profit organization of state gas pipeline safety directors, managers, inspectors, and technical personnel who serve to support, encourage, develop and enhance pipeline safety regulation. NAPSR submits resolutions to RSPA annually that identify serious pipeline safety concerns of national scope for consideration in regulatory and enforcement activities.

In 1990, RSPA asked NAPSR to review the pipeline safety standards in 49 CFR part 192. The review was to focus on regulations where revision was needed in order to make the regulations more explicit, understandable and enforceable. RSPA limited the review to the 20 highest priority issues with two of those issues relating to corrosion control. For fiscal year 1991, Congress appropriated funds to RSPA to procure technical assistance from state pipeline

inspectors in conducting an assessment of 49 CFR part 192.

NAPSR's report of its review is set forth immediately following this notice. The report is published in its entirety and includes background information, the 20 priority items, and 13 technical corrections. RSPA is considering each proposal to determine the appropriate action to take.

With regard to the NAPSR report, RSPA is particularly interested in receiving comments that address the safety problem implied by each proposal, discuss the effectiveness of any current Federal, state, or voluntary standard that relates to the problem, and describe ways now being applied or available to resolve the problem. Comments are also requested on the feasibility and cost-effectiveness of implementing each proposal or any alternative way to resolve the problem. In responding to this notice, commenters are requested to use section numbers to identify the proposal to which their specific remarks are addressed.

Authority: 49 App. U.S.C. 1671 and 1804; 49 CFR 1.53 and Appendix A to part 106.

Issued in Washington, DC, on November 4, 1993.

Richard L. Beam,

Acting Associate Administrator for Pipeline Safety.

REPORT ON RECOMMENDATIONS FOR REVISION OF 49 CFR PART 192

For the US-DOT Research and Special Programs Administration Office of Pipeline Safety; Prepared by the NAPSR Liaison Committee November 20, 1992

Introduction and Background

On January 21, 1988, in Docket No. PS-99, the Research and Special Programs Administration (RSPA) of the U.S. Department of Transportation adopted a number of amendments to the minimum pipeline safety standards of 49 CFR part 192. Most of the regulation changes had originally been proposed by the New England Gas Association (NEGA), which had submitted a list of 71 suggested changes intended to "clarify the intent of the regulations and reduce the cost of compliance without compromising pipeline safety."

The initiative taken by NEGA was noted by members of the National Association of Pipeline Safety Representatives (NAPSR). There was general discussion at the 1989 NAPSR National Meeting in New Orleans of whether a similar project, although geared more towards areas of enforcement problems, should be undertaken by NAPSR.

At the 1990 NAPSR National Meeting in Orlando, Florida, RSPA's Office of Pipeline Safety (OPS) approached NAPSR and requested a rules review study be made, with emphasis on those areas where the performance language of existing regulations was not sufficient to insure safe practices by pipeline operators, or to permit action by enforcement agencies. After further discussion at the 1991 NAPSR National Meeting in Santa Fe, the project was assigned to the NAPSR Liaison Committee, a standing committee established to provide a continuity of relationship among NAPSR members and between NAPSR and RSPA. RSPA specifically requested that NAPSR's study of recommended rule changes be limited to the 20 highest priority issues. In addition, at a later date RSPA specifically requested, in response to National Transportation Safety Board safety recommendations, that the committee include two corrosion control rules in its review.

During the term of this project, the Liaison Committee met five times, with each member hosting one meeting as follows:

October 1, 1991—Boston, MA
January 13-14, 1992—Sacramento, CA
March 17-18, 1992—Columbia, SC
May 19-20, 1992—Santa Fe, NM
August 17-19, 1992—Des Moines, IA

In the fall of 1991, the committee solicited input from the NAPSR members in their respective regions; a total of 48 state agencies plus the District of Columbia and the Commonwealth of Puerto Rico. Twenty-nine (29) agencies responded with 182 comments suggesting revisions covering 78 areas of Part 192.

The following exclusion criteria were applied to the suggestions. Suggestions were not taken up for review by the committee if:

(a) They involved issues already being addressed in an RSPA rulemaking or another NAPSR committee. No purpose was seen to duplicating efforts being made in other forums.

(b) They proposed substantive new requirements, as opposed to issues of clarity or enforceability. This committee was not seen as a proper forum for the proposal of significant new regulatory requirements or to address disagreements with current requirements. (For example, a suggestion that a test be required twice rather than once a year would not have been entertained, but a request that "periodic" be quantified would be.)

Application of these criteria and merging of duplicate submittals reduced to 49 the number of suggestions the

committee would pursue. As the meetings progressed, this number was gradually further reduced to the 20 items considered by the committee to have the highest priority, as requested by RSPA. The text accompanying each suggested rule change was drafted in a manner intended to assist in preparation by RSPA of a Notice of Proposed Rulemaking incorporating these items.

The committee also developed a list of 13 additional items that have been designated "Technical Corrections." These were incidental suggestions for improving part 192 that did not represent enforcement problems and were not priority items. These suggestions propose removal of old dates, eliminating conflicting language, minor language changes to improve clarity, etc. The committee decided that such suggestions could easily be noted and provided to RSPA as non-priority recommendations for "cleaning up" part 192.

Much of part 192 is written in performance language. Those committee proposals which would replace general performance language with more specific criteria should not be taken as dissatisfaction by NAPSR with that concept. Rather, they represent instances where experience by NAPSR members has shown the present rule provides insufficient guidance to operators on what constitutes safe and acceptable practice.

On August 31, 1992, RSPA published a Notice of Proposed Rulemaking in Docket PS-124 (57 FR 39572), which proposes various amendments to part 192 intended to reduce the economic impact of compliance with pipeline safety standards. Several of these proposed amendments address the same code sections and/or issues as the NAPSR committee. Since this was published after the final committee meeting, and no additional meetings have been scheduled, there is no opportunity to reconcile the committee's report with the new rulemaking. However, the following comments can be made. (These remarks mirror comments filed by Iowa in PS-124, and are therefore not an attempt at ex parte communication as they only repeat information already in the docket record.)

a. Several comments received by the committee alleged significant technical discrepancies between part 192 and industry standards for LPG facilities. This committee is recommending this issue be examined by a separate committee, preferably one comprised of NAPSR members with LPG expertise. One option that group would explore is whether regulations separate from part

192 should be adopted for LPG operators. PS-124 also proposes consideration of separate rules for LPG facilities. However, the rationale between the committee's and the PS-124 proposals are completely different and these are not duplicative proposals.

b. The committee and PS-124 propose differing modifications to the definition of a transmission pipeline in § 192.3. The committee prefers its version, as it addresses more of the past problems with that definition than does the docketed proposal.

c. The committee report recommends that the permissible levels of hydrogen sulfide in § 192.475 be stated in parts-per-million as well as in grains.

d. The committee supports the adoption of ASME B31G in part 192, but had proposed it be incorporated in a different manner than proposed in PS-124. A 1986 NAPSIR resolution proposing adoption of that standard was submitted to RSPA, but RSPA declined to act on this resolution, citing the availability of other valid methods, availability of the B31G methodology in other publications, and a RSPA policy of limiting the number of referenced standards. The NAPSIR committee recommendation was therefore written to refer to B31G in the applicable code section, rather than Appendix A.

The Liaison Committee believes that these proposed revisions and technical corrections to 49 CFR part 192 which are based on the comments received from the NAPSIR membership, addresses the concerns of the RSPA to clarify and improve the regulations.

Therefore, RSPA is urged to review this report and initiate rulemaking for the adoption of these recommendations.

Respectfully Submitted,

Richard G. Marini,

Chair, New Hampshire

Donald Stursma, Iowa

Jim Wait, California

Albino Zuniga, New Mexico

Carl Morse, South Carolina

§ 192.3 Definitions.

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

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

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

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

(c) Transports gas within a storage field.

Problem

Despite numerous interpretations by the Office of Pipeline Safety (OPS) over the years, the determination of whether certain pipelines are transmission pipelines or mains has remained unclear for both operators and enforcement personnel. Of the three-part definition of "transmission line" in § 192.3, parts (b) and (c) are straightforward and have caused no significant difficulty; the problem lies in determining what additional pipelines are included under part (a).

Recommendation

It is recommended part (a) of the transmission line definition in § 192.3 be reworded as follows. This language is consistent with past Office of Pipeline Safety (OPS) interpretations of this section dated July 27, 1971; May 8, 1974; November 30, 1978; May 23, 1979 (#79-16); and February 14, 1990. Also, to further clarify the distinction between a transmission line and a main, it is recommended the ASME B31.8 definition of a main be adopted.

Modification

Revise the § 192.3 definitions of Main and Transmission Line to read:

Main means a pipeline installed in a community to convey gas to individual service lines or to other mains.

Transmission line means a pipeline, or a series of pipelines, other than a gathering line, that:

(a) Transports gas from a gathering line, storage field or another transmission line to a storage field or to one or more distribution systems or other load centers.

(b) & (c)—unchanged.

§ 192.225 Welding—General.

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

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

Problem

This subpart does not require that the welding procedure used be developed and qualified in accordance with accepted industry practices such as American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or other standards, thereby allowing the operator to use a

qualification procedure developed in-house and difficult to evaluate.

Recommendation

The addition of American Petroleum Institute (API) and American Society of Mechanical Engineers (ASME) references will better define appropriate standards for welding procedure qualification. The proposed changes will promote understanding between operators and enforcement personnel, assist in making this regulation more easily understood, and enhance consistency of welding procedure test methods.

Modification

Revise § 192.225(a) to read as follows:

(a) Welding must be performed by a qualified welder in accordance with procedures qualified under American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or other standards to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify the procedure shall be determined by destructive testing.

§ 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 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 6 of American Petroleum Institute (API) Standard 1104.

Problem

§ 192.241(a) requires the visual inspection of all welds. The regulations do not set forth the required qualifications of the person making the visual inspection. This failure to specify the qualification of that person is an obvious shortcoming in the welding

regulations, because it would allow a casual visual review of welds by a non-qualified person. Moreover, this is not consistent with the requirements for inspecting the joining of plastic pipe (§ 192.287), which require a qualified inspector in all cases.

Recommendation

The consequences of a welded steel joint failure could be just as severe as a failure of a plastic pipe joint. Therefore, the inspector qualification requirements should be comparable.

Modification

Revise § 192.241 (a) to read as follows:

(a) Visual inspection of welding must be conducted, by an inspector qualified by appropriate training and experience, to insure that: * * *

§ 192.285 Plastic pipe; qualifying persons to make joints.

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

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

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and
(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under § 192.283(a) applicable to the type of joint and material being tested;
(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
(iii) Cut into at least 3 longitudinal straps, each of which is:

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

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

(1) Does not make any joints under that procedure; or
(2) Has 3 joints or 3 percent of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under § 192.513.

(d) Each operator shall establish a method to determine that each person

making joints in plastic pipelines in his system is qualified in accordance with this section.

Problem

Approximately 85% of the distribution piping installed in recent years has been polyethylene (PE) pipe. Yet the qualification requirements for persons joining plastic pipe are less stringent than for welders on comparable projects using steel pipe. Under the present requirements of § 192.285(c) a person who makes plastic pipe joints periodically, of sufficient quality that the joints withstand the pressure test required by § 192.513, need never retake a qualifying test. These requirements should be strengthened to insure that the joints are being made in full compliance with joining procedures proven to produce strong gastight joints with adequate long-term strength.

Further, a joiner is required by § 192.285(c)(2) to requalify if a certain number of inadequate joints fail during pressure testing, but there is no provision for retesting if poor quality joints are discovered by other means. A person would not be retested (and possibly precluded from further joining unless and until the test was passed) even if numerous poor quality production joints were found. Also, this section is not consistent with § 192.227, which requires a welder be periodically requalified regardless of the number of wells made. The consequences of a plastic pipe joint failure could be just as severe as a failure of a welded steel joint; therefore, the personnel qualification requirements should be comparable.

Iowa (1983, NTSB Report No. NTSB/ PAR-84/02) and Kansas (1987, KCC Report No. 87-25) have both had major incidents which resulted from failure of "cold" fusion joints which had not been made in accordance with procedure. Improper qualification of joiners was not cited in either case, but these events show a need for periodic retesting to insure joiners know and follow proper procedure.

The present language of § 192.285(d) also requires that:

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

It appears this provision is intended to require that the operator monitor the activities of joiners, both its own and contractor employees, to insure they are properly qualified. However, the language lacks both the strength and specificity needed to insure that

operators properly monitor and verify that joiners are properly qualified and that their qualification is maintained. The lack of recordkeeping requirements in particular makes it difficult to obtain evidence needed for enforcement of joiner qualification requirements.

Recommendation

It is recommended § 192.285 (c) and (d) be amended to require periodic retesting of persons making plastic pipe joints, require qualification records be kept, and provide a means of requiring requalification of a person found to be making substandard production joints, and to make its joiner qualification requirements consistent with § 192.227.

Modification

Revise § 192.285 (c) and (d) to read as follows:

(c) A person must be requalified:

(1) In all applicable procedures, at least once each calendar year at intervals not exceeding 15 months; or
(2) In the applicable procedure if, since their last qualification test, 3 joints or 3 percent of the production joints made, whichever is greater, using that procedure are found unacceptable by testing under § 192.513, or which fail a test made according to the procedures of § 192.285(b)(2).

(d) Each operator shall establish a method to verify that each person making joints in plastic pipelines is and remains qualified in accordance with this section. This method shall include records of the procedures in use, joiner qualification tests and any failed production joints.

§ 192.321 Installation of plastic pipe.

§ 192.361 Service lines: Installation.

Problem

On January 8, 1992, in response to NAPSIR resolution (No. 1992-2-E-WV-P1), the Office of Pipeline Safety issued an Alert Notice (ALN-92-01) which documented three instances reported by NAPSIR members of lightning conducted through tracer wire damaging plastic pipe and causing it to leak. In all these instances, the tracer wire had been wrapped around the pipe at the time of installation. One of these incidents resulted in three fatalities and over \$50,000 in property damage. NAPSIR is also aware of other incidents in New Hampshire and South Carolina where leaks were caused by lightning conducted through tracer wire which was not wrapped around the plastic pipe, but was in contact with it at one or more places.

Section 192.321, "Installation of Plastic Pipe" requires in paragraph (e)

that "Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground." This rule does not prohibit contact between the pipe and tracer wire. In addition, this regulation is located in subpart G, which is only applicable to transmission lines and mains. There is no comparable requirement in subpart H to insure that service lines can be located. Section 192.361, "Service lines: Installation," is silent on this subject.

The American Gas Association (AGA), in its publication entitled "Plastic Pipe Manual for Gas Service," recommends a two to six inch separation between the pipe and tracer wire to reduce the risk of lightning damage. Although the Alert Notice mentions the American Gas Association (AGA) criteria, the notice is an advisory only, and does not constitute a requirement that plastic pipe and tracer wire not be in contact.

However, NAPSRS recognizes that there are situations where requiring a separation between the pipe and locating wire would be impractical. For example, in trenchless construction, such as at road crossings, the common practice is to run the pipe and wire through the same borehole or casing. Requiring a second borehole or casing for the tracer wire to insure separation would add substantially to installation costs.

NAPSRS also recognizes that tracer wires may be affected by corrosion. If the electrical continuity is lost due to corrosion, it cannot be used to locate the plastic pipe. It is becoming common practice for operators to connect anodes to these wires for protection from corrosion.

Recommendation

Section 192.321 should require that each gas operator using tracer wire to comply with § 192.321(e) lay the tracer wire with a separation from the pipe. The regulation should also recognize the impracticality of avoiding contact in all circumstances; and also provide for protection of the tracer wire, or any other metallic element used as a locating method, from corrosion.

Tracer wire, or other means of locating plastic pipe, should also be required for plastic service lines. An additional paragraph should be added to § 192.361 containing requirements for a means of locating similar to § 192.321(e).

Modification

Revise § 192.321(e) to read as follows:

(e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe

while it is underground. Where practical, tracer wire or other metallic locating assists shall not be in contact with the pipe. Tracer wires, or other metallic elements installed for pipe locating purposes, shall be protected from corrosion.

And add a new paragraph § 192.361(g) reading as follows:

(g) Plastic service lines that are not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Where practical, tracer wire or other metallic locating assists shall not be in contact with the pipe. Tracer wires, or other metallic elements installed for pipe locating purposes, shall be protected from corrosion.

§ 192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

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

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

(1) Bare or ineffectively coated transmission lines.

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

(3) Bare or coated distribution lines. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

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

§ 192.465 External corrosion control: Monitoring

Problem

Section 192.457(b)(3) requires that areas of active corrosion must be

determined on bare or coated distribution lines installed before August 1, 1971. Section 192.465(e) requires reevaluation of unprotected pipelines every three years for areas of active corrosion. Where practical, this must be done by electrical survey.

Where electrical surveys are not practical, it must be done "by the study of corrosion and leak history records, by leak detection survey, or by other means." (Emphasis added)

The advantage of an electrical survey, and presumably therefore the preference given it in the rules, is that it is proactive. It is the only method which can anticipate where corrosion may occur, and permits corrective action to be taken before significant damage results. The alternative methods require first that corrosion actually occur, and second that the damage then be discovered. Such reactive tactics carry a risk that corrosion will create a hazard before its presence is determined.

However, there are many limitations on the use of electrical surveys. Such surveys require that numerous pipe-to-soil electrical potential readings be taken over the pipeline and the results analyzed to identify any areas where current is leaving the pipe and corrosion may be occurring. In many instances they are impractical because the necessary data cannot be obtained due to difficulties created by extensive paving, electrically discontinuous pipe, or electrical interference. Even if sufficient readings can be taken, their evaluation requires considerable expertise. NAPSRS is concerned that the necessary expertise is not always available, with operators not properly understanding how an electrical survey is to be conducted, and Subpart I provides little guidance. In contrast, § 192.455(b) provides very specific instructions for evaluating the corrosion potential on lines installed after July 31, 1971.

Further, the effort required to obtain and analyze these readings causes electrical surveys to be expensive; NAPSRS is aware of operators who have claimed such surveys are impractical on the basis of cost alone. In addition, the electrical survey method was originally developed for transmission lines, and the difficulty of its application to often much more complex distribution systems raises further concern about its reliability.

The language of §§ 192.457(b)(3) and 192.465(e) creates several problems. Due to the difficulty and expense of obtaining and analyzing electrical survey data, operators often would prefer to use alternative methods to evaluate their unprotected pipe.

Because "impractical" is not defined, there is frequent uncertainty and disagreement among both operators and enforcement agencies as to when alternative methods are permissible. Certain types of potentially useful alternative information are listed, but no guidance as to their anticipated source or method of analysis. Further, the word "or" in the regulations implies that any single alternative method is adequate, instead of requiring the operator to consider all available information. In contrast, the continuing surveillance requirement of § 192.613 requires the operator to evaluate the condition of pipe based on all known factors.

One other means which has been suggested to anticipate areas of active corrosion is to obtain soil resistivity data on the soil in which the unprotected pipe is buried. Such information may indeed be useful; however, there are practical concerns which must be considered. The soils in developed areas are likely to be widely varied due to numerous past fill and/or excavation activities, including use of imported material for fill or utility trench backfill. Soil resistivity surveys would therefore have to be detailed and subsequently expensive. In the locations they would provide the greatest benefit, they may be impractical for the same reasons electrical surveys are impractical. Where electrical surveys are not impeded, there appears little justification for requiring the expensive additional data. Therefore, a requirement that soil resistivity data be obtained is not proposed. However, that does not preclude its consideration where such information is available.

§ 192.465(e) requires unprotected pipe be re-evaluated at three year intervals, while leak surveys outside of principal business areas of distribution systems are only required by § 192.723(b)(2) to be made every five years. Depending how the two cycles synchronize, decisions on whether active corrosion is occurring could be made using leak data which is several years old. However, because this particular issue is being considered in RSPA Rulemaking Docket No. PS-123, it will not be pursued here.

Recommendation

NAPSR sees a need to clarify when alternatives to electrical surveys are permissible, to identify sources of data, and to require that all available information be used when alternative methods are permitted.

Modification

Revise § 192.457(b)(3) and § 192.465(e) to read as follows:

§ 192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

(b) * * *

(3) Bare or coated distribution lines. The operator shall determine the areas of active corrosion by electrical survey; or where an electrical survey is impractical due to extensive paving, electrically discontinuous pipe, or electrical interference; by the study of all available information which may indicate the presence of corrosion, including leak survey (§§ 192.706 & .723) and leak history records, pipe coating and external condition examination records (§ 192.459), available soil resistivity data, and such pipe-to-soil readings as can be obtained. For the purpose of this section, an electrical survey is a series of closely spaced pipe-to-soil readings over a pipeline which are subsequently analyzed by plotting or comparable means to identify any locations where a corrosive current is leaving the pipe.

§ 192.465 External corrosion control: 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 due to extensive paving, electrically discontinuous pipe, or electrical interference; by the study of all available information which may indicate the presence of corrosion, including leak survey (§§ 192.706 & .723) and leak history records, pipe coating and external condition examination records (§ 192.459), available soil resistivity data, and such pipe-to-soil readings as can be obtained. For the purpose of this section, an electrical survey is a series of closely spaced pipe-to-soil readings over a pipeline which are subsequently analyzed by plotting or comparable means to identify any locations where a corrosive current is leaving the pipe.

§ 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 paragraph of §§ 192.485, 192.487, or 192.489.

Problem

Some operators have misinterpreted this section, contending it is applicable only to pipelines that are bare or have deteriorated coating, and therefore § 192.491(b)(2) does not require an examination record be kept if the pipe was found with good coating. The lack of records on examination of coated pipe in good condition not only deprives both the operator and enforcement agencies of information on pipe and coating condition, but without such records there is no way to verify that exposed pipe is actually being examined as required by the section.

Recommendation

NAPSR believes this incorrect interpretation could be prevented if the section were clarified and a reference § 192.491(b)(2) added.

Modification

Revise § 192.459 to read as follows: Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined to determine the condition of the coating, or if the pipeline is bare or the coating is deteriorated, the exterior condition of the pipe. A record of the pipe and/or coating condition shall be made in accordance with § 192.491(b)(2). 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, and 192.489.

§ 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.

§ 192.483 Remedial measures: General.

Problem

Although § 192.467(c) generally states that each pipeline must be electrically isolated from metallic casings that are a part of the underground system, there is no specific requirement in the rule that casings be periodically tested for isolation, and § 192.467(d) gives no guidance regarding the frequency for tests for electrical isolation. This lack of clarity has caused some operators to fail to test pipeline casings for isolation, or to test at intervals not consistent with the other periodic cathodic protection test requirements of this subpart.

The rule also states that "if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing." Office of Pipeline Safety (OPS) has developed an enforcement policy on what "other measures" are acceptable, and if only these specific remedial measures are acceptable then they should be made part of the rule. Specifying acceptable action in the regulation would also eliminate inappropriate practices which have been used by some operators, such as bonding of casings and carrier pipe in apparent misinterpretation of § 192.467(a).

Recommendation

Add provisions to § 192.467(d) requiring periodic testing of casings for electrical isolation and specify in § 192.483 permissible remedial actions if electrical contact is found.

Modification

Revise § 192.467(d) and add a new § 192.483(d) as follows:

§ 192.467(d)

Inspection and electrical tests must be made to assure electrical isolation is adequate. Each metallic casing must be tested each calendar year but at intervals not exceeding 15 months for possible electrical contact to the pipeline. Where contact between a

pipeline and a casing is found, remedial action shall be taken in accordance with § 192.483(d).

§ 192.483(d)

If it is determined that a casing is shorted to a pipeline the operator shall:

- (1) Clear the short, if practical.
- (2) Fill the casing with a high dielectric filler or other corrosion inhibiting material. The filler level in the casing shall be tested not less than once annually but at intervals not to exceed 15 months to determine whether the filler material is leaking from the casing.
- (3) If (1) and (2) are impractical and the risk to the public from a corrosion leak would be minimal, the encased pipeline shall be monitored for leakage with leak detection equipment, at intervals not to exceed the requirements of § 192.706(b) or 192.723(b).
- (4) In lieu of (1)–(3), conduct an inspection at intervals not exceeding five years with an internal inspection device capable of detecting external corrosion in the cased pipeline.

§ 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.

Problem

§ 192.487(a) requires replacement of steel pipelines with "generalized corrosion", unless the area of general corrosion is "small", in which case the pipe may be repaired. Section 192.487(a) does not define, describe nor limit what constitutes allowable "small areas" of corrosion which may be repaired. Not properly defining "small areas" often allows repair of corroded pipe sections which should be replaced. The present vague language sets up inevitable conflicts between pipeline operators, contractors, and regulators.

Recommendation

The Gas Piping Technology Committee (GPTC), in their "Guidelines

for Gas Transmission and Distribution Piping Systems", Appendices G6 through G8, provides specific criteria and procedures for evaluating the extent of corrosion damage. This criteria for determining the remaining strength of corroded pipe is also found in ASME Standards B31.4 and B31.8, and is published separately as B31G, "Manual for Determining the Remaining Strength of Corroded Pipelines".

These standards should be specifically referenced, and these types of calculations required in determining whether pipelines with corrosion must be replaced or may be merely repaired.

Modification

Revise § 192.483 to include (e) as follows (Note that the addition of (d) is proposed elsewhere):

(e) Appropriate guides and standards such as those published by American Society of Mechanical Engineers (ASME), American National Standards Institute (ANSI), and the Gas Piping Technology Committee (GPTC) shall be used in determining the remaining strength of pipelines with corrosion.

§§ 192.505 and 192.507 Test Requirements (See also § 192.619(a)(2))

§ 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 percent 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 percent 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 percent 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.

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 psig.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 psig must be tested in accordance with the following:

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

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

- (1) A leak test must be made at a pressure between 100 psig and the pressure required to produce a hoop stress of 20 percent of SMYS; or
 - (2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.
- (c) The pressure must be maintained at or above the test pressure for at least 1 hour.

Problem

Section 192.505 contains strength test requirements for steel pipelines which will operate at a hoop stress over 30% SMYS, and § 192.507 contains the requirements for pipelines which will operate between 100 psig and 30% SMYS. Neither of these sections specifies the required minimum test pressure. Section 192.503(a)(1) states the test must be conducted in accordance with subpart J and § 192.619. However, this is not always sufficient to advise operators that they must refer to the Maximum Allowable Operating Pressure (MAOP) regulations of § 192.619 to obtain the required minimum test pressure. Errors of this type result in strength tests which do

not support the intended Maximum Allowable Operating Pressure (MAOP). Further, § 192.505 states pipelines to operate at 30% of SMYS or more must be tested in accordance with that section, an apparent conflict with § 192.503 and one which could be interpreted to make § 192.503(a)(1) inapplicable.

Recommendation

It is recommended § 192.505 and § 192.507 be amended to make specific reference to § 192.619(a)(2)(ii) as the source of the required minimum test pressure.

Modification

Revise § 192.505(a) and § 192.507 to read as follows:

§ 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 percent or more of SMYS must be strength tested in accordance with this section and with § 192.619(a)(2)(ii) to substantiate the proposed maximum allowable operating pressure.

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 psig.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress of less than 30 percent of SMYS and at or above 100 psig must be tested in accordance with § 192.619(a)(2)(ii) and with the following:

§ 192.509 Test requirements for pipelines to operate below 100 psig, and § 192.511 Test requirements for service lines (other than plastic)

§ 192.509 Test requirements for pipelines to operate below 100 psig

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

§ 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 psig but not more than 40 psig must be given a leak test at a pressure of not less than 50 psig.

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

Problem

These two sections contain the test requirements applicable to the majority of non-plastic mains and service lines. There are frequent inconsistencies in these regulations. Mains and services are operated in common in a distribution system, but the test requirements for lines which would operate at the same pressure are not the same, and although the service line is the closest to the customer the test requirements are less stringent. There is a test requirement for low pressure mains but none for low pressure services. Further, the higher the proposed operating pressure, the lower the safety factor of the test pressure, until it is less than 1.0 for lines operating between 90 and 100 psig. In comparison, plastic lines (§ 192.513), and steel lines operating above 100 psig in the same urban (Class 3) environment (§§ 192.505 and 507), must be tested to at least 1.5 times the operating pressure.

Recommendation

No valid reason is known for these discrepancies in the code. Further, the lack of continuity and consistency compromises safety. It is recommended that §§ 192.509(b) and 192.511 (b) and (c) be amended to improve clarity and remove inconsistencies.

Modification

Revise §§ 192.509(b) and 192.511 (b) and (c) to read as follows:

§ 192.509(b)

Each main that is to be operated at less than 1 psig must be tested to at least 10 psig, and each main to be operated at or above 1 psig must be tested to 90 psig or 1.5 times the intended operating pressure, whichever produces the higher test pressure.

§ 192.511(b)

Each segment of a service line (other than plastic) that is to be operated at less than 1 psig must be tested to at least 10 psig, and each service line to be operated at or above 1 psig must be tested to 90 psig or 1.5 times the intended operating pressure, whichever produces the higher test pressure.

§ 192.511(c)

Each segment of a steel service line stressed at its intended operating pressure to 20% or more of SMYS must be tested in accordance with § 192.507 of this subpart.

§ 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.

Problem

This regulation does not require retention of pressure test records under § 192.509 for pipelines to operate below 100 psig, under § 192.511 for service lines, or § 192.513 for plastic pipelines. The lack of appropriate records makes it impossible for the operator to demonstrate to enforcement personnel whether a pipeline has been properly tested and whether the Maximum Allowable Operating Pressure (MAOP) was properly established.

Recommendation

The regulation should require retention of pressure test records for pipelines tested under § 192.509 for pipelines to operate below 100 psig, § 192.511 for steel service lines, and § 192.513 for plastic pipelines. Including these additional requirements under § 192.517 will ensure that pipeline operators have documentation of the required pressure tests, and can verify that the pipelines were properly tested.

Modification

Revise § 192.517 to read as follows:
Each operator shall make, and retain for the useful life of the pipeline, a

record of each test performed under §§ 192.505, 192.507, 192.509, 192.511, and 192.513. 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.

§ 192.614 Damage prevention program.

(a) Except for pipelines listed in paragraph (c) of this section, each operator of a buried pipeline shall carry out in accordance with this section a written program to prevent damage to that pipeline by excavation activities. For the purpose of this section, "excavation activities" include excavation, blasting, boring, tunneling, backfilling, the removal of above ground structures by either explosive or mechanical means, and other earth moving operations. An operator may perform any of the duties required by paragraph (b) of this section through participation in a public service program, such as a "one-call" system, but such participation does not relieve the operator of responsibility for compliance with this section.

(b) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.

(2) Provide for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (b)(1) of the following as often as needed to make them aware of the damage prevention program:

(i) The program's existence and purpose; and

(ii) How to learn the location of underground pipelines before excavation activities are begun.

(3) Provide a means of receiving and recording notification of planned excavation activities.

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

(5) Provide for temporary marking of buried pipelines in the area of

excavation activity before, as far as practical, the activity begins.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

(ii) In the case of blasting, and inspection must include leakage surveys.

(c) A damage prevention program under this section is not required for the following pipelines:

(1) Pipelines in a Class 1 or 2 location.

(2) Pipelines in a Class 3 location defined by § 192.5(d)(2) that are marked in accordance with § 192.707.

(3) Pipelines to which access is physically controlled by the operator.

(4) Pipelines that are part of a petroleum gas system subject to § 192.11 or part of a distribution system operated by a person in connection with that person's leasing of real property or by a condominium or cooperative association.

Problem

The requirement in § 192.614(b)(2) that notification to the public and known excavators of the details of the operator's damage prevention program be made " * * * as often as needed * * *" leaves a great disparity amongst operators on time frames for notifications and does not give the enforcement personnel a limit for acceptability.

Recommendation

Establish a maximum time interval requirement for the notifications required by § 192.614(b)(2). To be consistent with other periodic requirements of Part 192, one year has been selected.

Modification

Revise § 192.614(b)(2) to read as follows: § 192.614(b)(2).

Provide for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (b)(1) of the following as often as needed but at least once each calendar year, at intervals not exceeding 15 months, to make them aware of the damage prevention program.

§ 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.

Problem

In § 192.615(a)(3)(i), it is unclear whether "detected" includes situations where the presence of gas is suspected but has not been confirmed, such as a report of a gas odor. NAPSRS is aware of operators who have not treated reports of gas odors as emergencies, contending that the present rule does not require emergency response to such reports. A report of a gas odor may indicate an emergency, therefore the regulations should clearly state that confirmation of the presence of gas is not a prerequisite for emergency response.

Recommendation

Revise § 192.615(a)(3)(i) to include a report of gas odor as an event to be treated as an emergency.

Modification

Revise § 192.615(a)(3)(i) to read as follows:

(i) Gas detected or a report of gas odor inside or near a building.

§ 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 for 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.

Problem

Section 192.625(a) requires that gas be odorized so that the gas is detectable by persons with a normal sense of smell at a concentration of $\frac{1}{5}$ of the lower explosive limit. The rule does not specifically require the use of an instrument to determine the gas concentration. Some operators have relied strictly on "sniff tests", which can only determine if an odor is present, to determine if the odor is detectable. However, without an instrument, the concentration of gas in air cannot be measured, and compliance with the rule

cannot be determined. NAPSRS is aware of several National Transportation Safety Board (NTSB) reports where accidents occurred and the people in the area did not smell the gas.

In addition, § 192.625(f) provides no guidance on how often the adequacy of the odorant concentration must be tested. NAPSRS feels such tests must be made fairly frequently to insure the public safety, but is aware of operators whose Operating and Maintenance Plans call for such test as seldom as annually.

Recommendation

It is recommended § 192.625(f) be amended to establish a specific maximum sampling interval, and to specifically require use of an instrument capable of determining the percentage of gas in air when testing the adequacy of odorant concentration. Due to possible variances in odorization rates, NAPSRS believes it is necessary to require that sampling be done at least six times per year, at intervals not to exceed 2½ months.

Modification

Revise § 192.625(f) to read as follows:

(f) Each operator shall, at intervals not exceeding 2½ months but at least six times each calendar year or more often as necessary, conduct sampling of combustible gases to assure the proper concentration of odorant in accordance with this section. Sampling shall be done using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable.

§§ 192.739 Pressure limiting and regulating stations: Inspection and testing, and 192.743 Pressure limiting and regulating stations: Testing of relief devices.

§ 192.739 Pressure limiting and regulating stations: Inspection and testing.

Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

(a) In good mechanical condition;

(b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(c) Set to function at the correct pressure; and

(d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

§ 192.743 Pressure limiting and regulating stations: Testing of relief devices.

(a) If feasible, pressure relief devices (except rupture discs) must be tested in place, at intervals not exceeding 15 months, but at least once each calendar year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made at intervals not exceeding 15 months, but at least once each calendar year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works. After the initial calculations, subsequent calculations are not required if the review documents that parameters have not changed in a manner which would cause the capacity to be less than required.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.

Problem

Section 192.739 requires an annual inspection of regulators and overpressure protection devices to determine, among other things, that they are "set to function at the correct pressure". The regulation contains no instruction or guidance on what is meant by the "correct pressure" or on how to determine whether a set point complies with Part 192 requirements. Section 192.743 requires the adequacy of relief device capacity be verified annually, but contains undefined phrases such as "enough capacity", "desired maximum pressure", "relieving capacity", and "insufficient capacity" with no instruction or guidance on how compliance is to be achieved.

The information and instructions necessary for compliance with these regulations are found in two other areas of part 192: the Maximum Allowable Operating Pressure (MAOP) standards of §§ 192.619, .621, and .623 which limit the normal downstream pressure to the MAOP, and the standards limiting the amount of pressure increase permitted during the operation of overpressure protection devices in § 192.201. However, § 192.201 is in the design subpart, the Maximum Allowable Operating Pressure (MAOP) standards are in the operations subpart, and §§ 192.739 and .743 are in the

maintenance subpart. There is no clear connection or correlation between these areas of the regulations. As a result, operators frequently do not understand the limitations on set points or the relief capacity requirements imposed by part 192.

Recommendation

It is recommended that § 192.739(c) be amended to establish the applicability of the Maximum Allowable Operating Pressure (MAOP) regulations and of § 192.201 to determining "correct" set point pressures; and § 192.743 be amended to establish the applicability of § 192.201 to the adequacy of relief valve capacity.

Modification

Revise §§ 192.739(c) and 192.743(c) to read as follows:

§ 192.739(c)

Set to control or relieve at the correct pressures, and that the set points do not exceed the downstream Maximum Allowable Operating Pressure (MAOP) or the overpressure protection pressure limits of § 192.201.

§ 192.743(c)

If the relieving device is of insufficient capacity to comply with § 192.201, a new or additional device must be installed to provide the additional capacity required.

§ 192.743 Pressure limiting and regulating stations: Testing of relief devices.

(a) If feasible, pressure relief devices (except rupture discs) must be tested in place, at intervals not exceeding 15 months, but at least once each calendar year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made at intervals not exceeding 15 months, but at least once each calendar year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works. After the initial calculations, subsequent calculations are not required if the review documents that parameters have not changed in a manner which would cause the capacity to be less than required.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.

Problem

Section 192.743(a) states that, if feasible, relief devices must be tested in place. Section 192.743(b) allows the adequacy of relief devices to be checked by calculations, but only if an actual test is not feasible. In practice, the vast majority of annual relief capacity checks are done by computation. In-place testing has the disadvantages of the cost, noise, and potential safety hazard of the escaping gas, and is often perceived as wasteful.

There is no known controversy concerning the merits of using computations in lieu of in-place testing for determining the adequacy of relief valve capacity. In fact, calculations can consider circumstances which may not be readily subject to testing; for example, one manufacturer's method for computing the flow rate through a failed regulator assumes less orifice restriction than can be achieved in a normally functioning regulator during an in-place test.

No justification is seen for requiring an operator to first demonstrate that in-place testing is not feasible before the calculation method can be used.

Recommendation

It is recommended that the "feasible" language be removed from § 192.743, and both methods be considered equal alternatives. Due to the manner in which § 192.743 is written, this requires substantial revision of the language.

Modification

It is recommended § 192.743 (a) and (b) be revised as follows:

§ 192.743(a)

At intervals not exceeding 15 months, but at least once each calendar year, each pressure relief device at a pressure regulating station must either be tested in place (except rupture discs), or calculations must be made, to verify that it has sufficient capacity to limit the pressure on the facilities to which it is connected to within the overpressure protection limits of § 192.201.

§ 192.743(b)

If the adequacy of a relief device is evaluated by calculations, the required capacity must be compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works. After the initial calculations, subsequent calculations are not required if the annual review documents that parameters have not changed in a manner which would cause the capacity to be less than required.

§ 192.745 Valve maintenance: Transmission lines.

Each transmission line valve that might be required during an emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

Problem

The regulation requires each transmission line valve which is potentially needed during an emergency must be inspected and partially operated at a specified frequency.

The regulation does not specify what action should be taken if the valve does not operate properly. Obviously the valve should be repaired or replaced, but the rule contains no guidance on appropriate time limits. NAPSRS feels that since virtually any transmission line valve could prove crucial in an emergency, remedial action should be initiated immediately.

Also, the phrase "inspected and partially operated" is somewhat vague and subject to misinterpretation. The expectations of part 192 for the performance of transmission line valves are found in the valve design requirements of § 192.179. It requires valves be accessible and protected from stress, tampering, unauthorized operation, and damage. However, it is located in the design subpart, while the periodic inspection requirement is in the maintenance subpart. For consistency the maintenance regulation should require the valve continue to meet design requirements.

Recommendation

Section 192.745 should be revised to provide guidance on what should be covered during a valve inspection, and to require remedial action be initiated immediately if problems are found.

Modification

Revise § 192.745 to read as follows:

Each transmission valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year. Immediate remedial action shall be initiated on any valve found to be inoperable, inaccessible, improperly supported or subject to external loads or unusual stresses, or inadequately protected from unauthorized operation, tampering or damage.

§ 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 15 months, but at least one each calendar year.

Problem

The distribution valve maintenance regulations are vague and prevent a lack of common understanding between operators and enforcement personnel because: (1) There is no cross reference to the design requirements to specify the factors to be considered during a "check"; (2) there is no requirement for remedial action if problems are found; and (3) it is unclear which valves are covered by this regulation.

The design regulations under §§ 192.179(b), .181(c) and .199(b) require that valves be designed to be accessible, and be protected from stress, tampering, damage and unauthorized operation. However, the maintenance regulations under § 192.745 and § 192.747 only require that valves be checked and serviced each calendar year. They do not contain provisions to ensure that the requirements of the design standards continue to be met during the time the valve is in service. There is no requirement for corrective action if a valve is found to be inaccessible, inoperable or is unprotected from stress, damage or unauthorized operation.

NAPSRS is particularly concerned about the failure of the rule to require prompt remedial action if problems are found. Inoperable or inaccessible valves could have serious consequences in an emergency and warrant immediate repair.

Each operator's Emergency Plan should include instructions on which valves are to be operated if an emergency shutdown or pressure reduction of a pipeline is required (see § 192.615(a)(6)). NAPSRS believes these "emergency valves" are the ones the regulation is intended to cover, not necessarily every valve in the distribution system.

Recommendation

Section 192.747 should be revised to provide specific guidance on the conduct of valve "checks", require prompt corrective actions, and clarify which valves should be covered.

Modification

Revise Section 192.747 to read as follows:

(a) Each distribution line valve designated by an operator for use in an emergency must be inspected, partially operated and serviced at intervals not to exceed 15 months but at least once each calendar year.

(b) Immediate remedial action shall be initiated on any valve found to be inoperable, inaccessible, improperly supported, subjected to external loads or unusual stresses, inadequately protected from damage, tampering or unauthorized operation.

Technical Corrections

§ 192.55 Steel pipe.

192.55 (a) and (d) state the requirements for new steel pipe to be qualified for use in gas systems, including provisions for qualification of pipe manufactured before November 12, 1970. These parts of the rules were adopted in Amdt. 192-12 to make it clear that pipe manufactured before that date and meeting certain requirements could still be used.

That date is long past and it is improbable that any pipe manufactured before November 12, 1970 remains stockpiled and awaiting use as new steel pipe. It is recommended 192.55 be amended to delete these old dates, which complicate the rule but no longer have a practical benefit, by deleting 192.55(d) and amending 192.55(a)(2) to read as follows:

(2) It meets the requirements of Section II of Appendix B to this part.

§ 192.65 Transportation of pipe.

192.65 requires rail shipment of pipe be in compliance with the 1972 edition of API RP5L1, and also contains special provisions for pipe shipped before February 25, 1975, and special pressure test requirements for pipe shipped prior to November 12, 1970. The purpose of those dates was to permit use of pipe shipped prior to the effective dates of Amdts. 192-12 and 192-17.

Those dates are long past and it is improbable that any pipe shipped prior to those dates remains stockpiled and awaiting use. It is recommended 192.65 be amended as follows to delete old dates which complicate the rule but no longer have a practical benefit:

§ 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 the transportation is performed in accordance with the 1972 edition of API RP5L1.

§ 192.123 Design limitations for plastic pipe.

192.123(b)(2) limits the operating temperature for thermoplastic pipe to the temperature at which its long-term hydrostatic strength was determined, but contains an exception allowing pipe

manufactured before May 18, 1978, to be operated at up to 100 degrees F. This exception was made in Amdt. 192-31 to "grandfather" pipe manufactured before the effective date of new plastic pipe standards.

May 18, 1978 is long past and it is improbable that any plastic pipe manufactured prior to that date remains stockpiled and awaiting use. It is recommended 192.123(b)(2) be amended to delete an old date which complicates the rule but no longer has a practical benefit: this could be accomplished by deleting the phrase "except that pipe manufactured before May 18, 1978 may be used at temperatures up to 38 °C (100 °F)" from the rule.

§ 192.197 Control of the pressure of gas delivered from high-pressure distribution systems.

192.197(a) states that for distribution systems operated at "less than 60 psig", if service regulators meet certain standards no other pressure limiting device is required. 192.197(b) states that if those criteria are not met, and the operating pressure is "60 psig or less", additional pressure control is required. 192.197(c) contains standards for control of customer delivery pressure when the operating pressure "exceeds 60 psig". There is therefore a 1 psig discrepancy between 192.197(a), and 192.197 (b) and (c).

It is recommended this discrepancy be eliminated by changing the "under 60 psig" in 192.197(a) to "60 psig or less".

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

Section 192.203(b)(2) requires a shutoff valve be installed in each takeoff line as near as practicable to the point of takeoff. "Takeoff line" is not defined, and there has been uncertainty among operators over the scope of this regulation, especially over regulator control lines in regulator runs. It is recommended § 192.203(b)(2) be revised to read:

(2) A shutoff valve must be installed in each instrument, control, and sampling line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

§ 192.311 Repair of plastic pipe.

This section requires that plastic pipe imperfections or damage be repaired by a "patching saddle" or removed. No one seems certain what a patching saddle is. NAPSRS is aware of a device used by some operators for temporary repairs which is sold as a patching saddle, but it is actually a type of leak clamp; the misleading name was apparently

adopted due to the language of this rule. NAPSRS has also seen advertisements for a hot-air repair method, and has heard that an epoxy-type repair material is being developed, but such methods would apparently not be permitted by the language of this section.

If Part 192 is to allow repair of plastic pipe, no reason is seen why repair methods should be limited to patching saddles, nor is the meaning of that term clear. It is recommended the phrase "by a patching saddle" be deleted from the section.

§ 192.353 Customer meters and regulators: Location.

Damage to meter sets by vehicles is a frequent cause of leaks and incidents. 192.353(a) requires that meters and service regulators be "protected from corrosion or other damage." This can readily be interpreted to include vehicular damage; however, it does not specifically require vehicular damage be considered. Due to the lack of specific language, when a damaged meter, or an unprotected meter set in an exposed location, is encountered, the applicability of this regulation is unclear.

It is recommended that 192.353(a) be revised to read:

(a) Each meter and service regulator, whether installed inside or outside a building, must be installed in a readily accessible location and be protected from corrosion, vehicular, or other damage.

§ 192.475 Internal corrosion control: General.

192.475(e) states "Gas containing more than 0.1 grain of hydrogen sulfide per 100 cubic feet may not be stored in pipe-type or bottle-type holders." While the use of "grains" to quantify minor gas components continues, parts-per-million (ppm) is also commonly used and may be more commonly understood. (Note much of the discussion in RSPA Rulemaking Docket PS-106 concerning allowable hydrogen sulfide levels is in ppm.)

It is recommended that the permissible level of hydrogen sulfide be stated in both grains and parts-per-million.

§ 192.479 Atmospheric corrosion control: General.

192.497(b) gave operators until August 1, 1971, to make an initial examination of exposed pipe for atmospheric corrosion and to take corrective action as needed. That deadline is long past, and the dates no longer serve a useful purpose and make the regulation unnecessarily wordy and confusing. In addition, the wording of

the regulation appears to assume that atmospheric corrosion requiring remedial action will not be found on pipe installed after July 31, 1971. Further, as worded the regulation does not apply to a pipeline section which was not installed aboveground but which has since become exposed.

It is recommended that 192.479 be amended to eliminate the unnecessary dates, and make the remedial action requirements applicable to all exposed pipe regardless of the date or original type of installation. Suggested wording is:

§ 192.479 Atmospheric corrosion control: General.

(a) Each aboveground pipeline or portion of a pipeline 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) If atmospheric corrosion is found on an aboveground pipeline or portion of a pipeline, the operator shall—

(1) Take prompt remedial action to the extent required by the applicable paragraphs of §§ 192.485, 192.487, or 192.489; and

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

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

Section 192.489(b) requires that if leakage may result from localized pipe graphitization, the pipe must be replaced, repaired, or sealed by internal sealing methods to prevent or arrest leakage. Leaks caused by graphitization would occur due to brittle failure of the weakened pipe, and the wording of the regulation appears to imply that internal sealing methods would strengthen the pipe. To prevent such misinterpretation, it is suggested the following language be added to § 192.489(b):

However, internal sealing shall not be considered a method of strengthening graphitized pipe.

§ 192.553 Upgrading: General requirements.

Unless Subpart K is read with great care, 192.557 can easily be misinterpreted as permitting the Maximum Allowable Operating Pressure to be increased without regard for whether the proposed MAOP is supported by pressure testing. For pipelines to be operated above 30% of

SMYS, the relevance of previous pressure tests is clearly stated in 192.555(c), but there is no comparable language applicable to pipelines to operate below 30% of SMYS in 192.557. Another difficulty to consider is that since Subpart K does not require test records be kept for pipelines operated below 100 psig, there may be no record of prior tests to facilitate uprating of service lines or non-steel pipelines. There is also wording in 192.557(c) which is inconsistent with other rule sections. It is recommended the following changes be made to clarify the requirements for uprating pipelines to be operated at less than 30% of SMYS and for non-steel pipelines:

§ 192.553 General requirements.

(d) Limitation on increase in maximum allowable operating pressure. Except as provided in § 192.555(c) and .557.c(1), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under § 192.619 and .621 for a new segment of pipeline constructed of the same materials in the same location and tested in compliance with § 192.619(a)(2).

§ 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.

(c) After complying with paragraph (b) of this section:

(1) 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 and .621, 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); or, for any pipeline operated at less than 100 psig and for which no test record was kept, the test pressure specified in the operator's procedures at the time of installation.

(2) The increase in operating pressure must be made in increments that are equal to 10 p.s.i.g. or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)(6) of this section apply, there must be at least two approximately equal incremental increases.

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

When 49 CFR Part 192 was first adopted, this rule required an initial determination of the class location of each pipeline having a hoop stress exceeding 40% of SMYS at its MAOP, comparison of its hoop stress to that permitted for that class location, and confirmation or revision of the MAOP as required. All action required by this rule was to be completed by December 31, 1974.

The deadline for action is long past, and there is no longer any purpose for an initial compliance period for these purposes. It is proposed that the outdated dates and instructions in this

rule be deleted, and that the amended rule address only the continuing need for operators to know the class location of these lines and whether their stress level is appropriate for the class location. The following language is suggested:

§ 192.607 Determination of class location and confirmation of maximum allowable operating pressure.

For each segment of pipeline with a maximum allowable operating pressure that will produce a hoop stress of more than 40 percent of SMYS, each operator shall determine—

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

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

§ 192.753 Caulked bell and spigot joints.

There is a conflict between § 192.621(a)(3), which allows a pressure of up to 25 p.s.i.g. in cast iron pipe with unreinforced bell and spigot joints; and § 192.753(a), which states that each cast iron bell and spigot joint subject to pressures of 25 p.s.i.g. or more must be sealed. It is recommended the discrepancy be removed by revising § 192.753(a) to read:

(a) Each cast-iron caulked bell and spigot joint that is subject to pressures of more than 25 p.s.i.g. must be sealed:

[FR Doc. 93-27492 Filed 11-8-93; 8:45 am]

BILLING CODE 4910-60-P