(c) The authorized bandwidth for emission type F3E transmitted by a FRS unit is 12.5 kHz.

10. Newly redesignated § 95.633 is amended by revising paragraph (b) to read as follows:

§ 95.633 Unwanted radiation.

* * * * *

(b) The power of each unwanted emission shall be less than TP as specified in the applicable paragraph:

Transmitter	Emission type	Applicable paragraphs
GMRS	A1D, A3E, F1D, G1D, F3E, G3E with filtering	(1), (3), (7)
	A1D, A3E, F1D, G1D, F3E, G3E without filtering	(5), (6), (7)
	H1D, J1D, R1D, H3E, J3E, R3E	(2), (4), (7)
FRS	F3E with filtering	(1), (3), (7)
Note: Filtering refers to the requirement in § 95.635(b) R/C:		
27 MHz band	As specified in § 95.629(b)	(1), (3), (7)
72–76 MHz band	As specified in § 95.629(b)	(1), (3), (7), (10), (11), (12)
CB	A1D, A3E	(1), (3), (8), (9)
	H1D, J1D, R1D, H3E, J3E, R3E	(2), (4), (8), (9)
	A1D, A3E type accepted before September 10, 1976	(1), (3), (7)
	H1D, J1D, R1D, H3E, J3E, R3E type accepted before September 10, 1986	(2), (4), (7)

* * * * *

11. Newly redesignated § 95.635 is amended by revising paragraph (a) to read as follows:

§ 95.635 Modulation standards.

(a) A GMRS transmitter that transmits emission types F1D, G1D, or G3E must not exceed a peak frequency deviation of plus or minus 5 kHz. A GMRS transmitter that transmits emission type F3E must not exceed a peak frequency deviation of plus or minus 5 kHz. A FRS unit that transmits emission type F3E must not exceed a peak frequency deviation of plus or minus 2.5 kHz, and the audio frequency response must not exceed 3.125 kHz .

* * * * *

12. Newly redesignated § 95.637 is amended by adding a new paragraph (d) to read as follows:

§ 95.637 Maximum transmitter power.

* * * * *

(d) No FRS unit, under any condition of modulation, shall exceed 0.500 W effective radiated power (ERP).

13. Newly redesignated § 95.645 is revised to read as follows:

§ 95.645 FRS unit and R/C transmitter antennas.

The antenna of each FRS unit, and the antenna of each R/C station transmitting in the 72–76 MHz band, must be an integral part of the transmitter. The antenna must have no gain (as compared to a half-wave dipole) and must be vertically polarized.

14. Newly redesignated § 95.647 is revised to read as follows:

§ 95.647 Power capability.

No CB or R/C station transmitter or FRS unit shall incorporate provisions for increasing its transmitter power to any level in excess of the limit specified in § 95.637.

15. Newly redesignated § 95.649 is revised to read as follows:

§ 95.649 Crystal control required.

All transmitters used in the Personal Radio Services must be crystal controlled, except an R/C station that transmits in the 26–27 MHz frequency band, and a FRS unit.

16. Appendix 1 to Subpart E is amended by adding the definition for ''FRS'', in alphabetical order, to read as follows:

Appendix 1 To Subpart E-Glossary of Terms

* * * * *

FRS. Family Radio Service.

* * * * *

[FR Doc. 96–14140 Filed 6–5–96; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 192

[Docket PS–124; Amdt. 192–76]

RIN 2137–AC25

Regulatory Review; Gas Pipeline Safety Standards

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

ACTION: Final rule.

SUMMARY: This final rule changes miscellaneous gas pipeline safety regulations to provide clarity, eliminate unnecessary or burdensome requirements, and foster economic growth. The changes result from a comprehensive review of the regulations RSPA has completed under President Clinton's Regulatory Reinvention Initiative to reduce the burden of government regulations. The changes are intended to reduce the costs of compliance without compromising safety.

EFFECTIVE DATE: This final rule is effective July 8, 1996. The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of July 8, 1996.

FOR FURTHER INFORMATION CONTACT: A. C. Garnett, (202) 366–2036, or L. M. Furrow, (202) 366–4559, regarding the subject matter of this amendment, or the Dockets Unit, (202) 366–5046 regarding copies of this amendment or other material in the docket.

SUPPLEMENTARY INFORMATION:

Background

Early in 1992, RSPA began an extensive review of the federal gas pipeline safety regulations (49 CFR part 192) and invited the public to participate (57 FR 4745, Feb. 7, 1992). The review was to see what changes were necessary to provide clarity, eliminate unnecessary or overly burdensome requirements, and foster economic growth. As a result of the review, RSPA published a Notice of Proposed Rulemaking (NPRM), proposing changes to 38 regulations in part 192 (Notice 1; 57 FR 39572, Aug. 31, 1992).

Then the National Association of Pipeline Safety Representatives (NAPSR) reported on a separate but related review of part 192. RSPA had asked NAPSR to identify regulations in part 192 that may not assure safety or that may be hard to enforce. Because the NAPSR report concerned a few of the regulations covered by the NPRM and had similar goals, we published the report and requested public comment on its various recommended rule changes (Notice 2; 58 FR 59431, Nov. 9, 1993). At the same time, we announced that in developing final rules under the NPRM, we would consider comments on any NAPSR recommendations that addressed the same issues as the NPRM. The period for public comment on the NAPSR recommendations was extended 90 days until April 11, 1994 (Notice 3; 58 FR 68382, Dec. 27, 1993).

Later on, President Clinton launched the Regulatory Reinvention Initiative (memorandum for Heads of Departments and Agencies; March 4, 1995), which, among other things, directed DOT and other Federal agencies to review and revise existing regulations to remove unnecessary or burdensome requirements. Today's publication of this Final Rule is a major step in carrying out that directive with respect to DOT's pipeline safety regulations.

Advisory Committee

The Technical Pipeline Safety Standards Committee (TPSSC), consisting of 15 members, was established by statute to consider the feasibility, reasonableness, and practicability of proposed pipeline safety regulations. In developing the final regulations, RSPA considered all final TPSSC votes and comments on the NPRM, including minority positions. A more detailed consideration of the TPSSC action is contained in the following section-by-section discussion of comments. A record of the TPSSC deliberation is available in the docket.

Discussion of Comments

RSPA received comments on the NPRM from 36 pipeline operators, 9 pipeline-related associations, 1 state agency, and 8 other commenters. More commenters submitted views on the NAPSR recommendations: 58 pipeline operators, 10 pipeline-related associations, 4 state agencies, and 5 other commenters.

The following discussion on development of the final rules explains how we treated TPSSC positions, comments on the NPRM, and comments on NAPSR recommendations related to NPRM proposals (§§ 192.3, 192.475, 192.485, and 192.607). We appreciate the comments on NAPSR recommendations that were not related to NPRM proposals. They will help us decide appropriate responses to those recommendations in an action separate from this rulemaking.

Small Gas Systems. The NPRM invited comments on the idea of whether RSPA should develop separate, more appropriate safety standards for small gas distribution systems. Such systems include master meter systems and petroleum gas systems serving mobile home or apartment complexes.

Although TPSSC did not address this matter, RSPA received comments from two pipeline operators, one state agency, and one mobile home association. The state agency said that it is not clear that separate regulations are required. This commenter suggested that a less complicated remedy might be to excerpt those portions of the regulations specifically applicable to small operators (deleting, for example, sections applicable to transmission lines) and publish the result as a guide or as instructional material.

Three commenters supported the need for more appropriate standards for small gas distribution systems. A mobile home association endorsed the idea of developing standards for small gas distribution systems, such as master-meter systems serving mobile home parks, and publishing the standards as a new part of title 49 of the Code of Federal Regulations. The mobile home association commented that if it were not for the Guidance Manual for Operators of Small Gas Systems published by RSPA, the average mobile home park operator would have difficulty determining which regulations in part 192 apply to master-meter systems.

RSPA believes that each of the suggestions has merit and will be useful in developing future pipeline safety agendas.

Section 192.1, Scope of Part

Section 192.1(b)(1) excepts from the scope of part 192 certain gathering lines on the outer continental shelf (OCS), but does not except similar gathering lines located in State offshore waters. Section 192.1(b)(1) reads as follows: ''This part does not apply to * * * (o)ffshore gathering of gas upstream from the outlet flange of each facility on the outer continental shelf where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream.'' Because RSPA treats OCS and State offshore gathering alike under part 192, we proposed to delete the phrase ''on the outer continental shelf'' so the exception would cover offshore gathering no matter where located. We also proposed to replace ''offshore gathering of gas'' with ''offshore pipelines,'' recognizing that the excepted pipelines may be either production or gathering lines.

Twelve TPSSC members voted for the proposal, two supported it but recommended a change, one member opposed it, and one abstained. The recommended change was that ''gathering of gas'' should be retained in § 192.1(b)(1), since proposed § 192.9 refers to gathering under § 192.1.

We did not adopt the TPSSC minority's recommended change because the excepted pipelines located upstream from the referenced offshore facilities may be either production lines or gathering lines. Also, the term ''offshore pipelines'' was used in a similar revision of 49 CFR 195.1(b)(5) that we made to clarify the jurisdiction of the hazardous liquid pipeline regulations over offshore pipelines (Docket PS–127; 59 FR 33388; June 28, 1994). As discussed below under the § 192.9 heading, § 192.9 has already been revised to cross-reference § 192.1. Since the cross- reference does not refer specifically to gathering lines, deleting the words ''gathering of gas'' from § 192.1(b)(1) should not hinder the understanding of § 192.9.

RSPA received 14 comments on the proposed rule change, nine from operators, four from pipeline-related associations, and one from a state agency. None of these comments opposed the proposal to change § 192.1(b)(1).

Section 192.3, Definitions

1. *Petroleum Gas.* A revised definition of ''petroleum gas'' is discussed below under the § 192.11 heading.

2. *Secretary.* The proposed revision of the definition of ''Secretary'' is no longer needed. Because the term ''Secretary'' is not used in part 192, the definition of ''Secretary'' was removed from § 192.3 in an earlier rulemaking (59 FR 17281; April 12, 1994).

3. *Transmission Line.* A longstanding RSPA interpretation holds that the definition of ''transmission line'' in § 192.3 encompasses lines that link gathering lines or transmission lines to large volume customers, such as factories or power plants. This interpretation was founded on the definition of ''transmission line'' in the 1968 edition of the American Society of Mechanical Engineers [ASME] B31.8 Code. This code, which was the cornerstone of part 192, defined transmission to end at large volume customers. RSPA proposed to codify the interpretation by restating the definition of ''transmission line'' under part 192 to

include a ''large volume customer'' as an end point of transmission.

Eleven TPSSC members voted for the proposal, three supported it with a recommended change, and one abstained. The members who recommended a change thought that RSPA should define ''large volume customer.'' As discussed further below, the final definition includes an explanation of this term.

Twenty-six entities commented on the NPRM proposal, including 19 pipeline operators, five pipeline-related associations, one state agency, and one industrial consumer. Of these commenters, only eight expressed unqualified support. Three commenters completely opposed the proposal, saying it was not needed or would create confusion.

RSPA continues to believe that the proposed change is needed. The present definition does not reflect RSPA's interpretation that the term ''transmission line'' includes pipelines that connect large volume customers to gathering or transmission lines.

Nine commenters thought the proposed definition would reclassify as transmission those pipelines that connect large volume customers to high pressure distribution lines. RSPA did not intend for the proposed change to alter the classification of distribution lines that supply large volume customers. To avoid this unintended outcome, the definition explicitly does not include lines serving large volume customers downstream from a distribution center.

Four commenters said that the volume of gas transported is not an appropriate indicator of transmission. This group suggested that engineering characteristics, such as high pressure, stress level, or connection to a pressure limiting station are more indicative of transmission than the volume of gas transported. However, the purpose of the transmission proposal was not to open discussion on whether volume is an appropriate indicator of transmission. The purpose was to recognize that, by interpretation of the present definition, volume already is an established indicator of transmission, and that the interpretation should be codified. None of the commenters challenged the correctness of the interpretation. Moreover, before publishing the proposed definition, we referred to the 1992 edition of the ASME B31.8 Code, a widely recognized code of voluntary standards for gas piping. Section 803.21 of the ASME B31.8 Code (1992 edition) defined ''transmission line'' as ''pipe installed for the purpose of transmitting gas from a source or sources of supply to one or more distribution centers or to one or more *large volume customers* * * *'' (emphasis added). And this definition is the same in the current 1995 edition of the code. Given our longstanding interpretation and the ASME B31.8 Code definition, we find it reasonable to add ''large volume customer'' to the definition of transmission line as proposed.

Three commenters wanted RSPA to define ''large volume customer.'' We agree that an explanation of ''large volume customer'' would make the final definition more precise. Thus, we added a statement to the final definition to explain that ''large volume customer'' includes factories, power plants, and institutional users of gas.

We did not specify a minimum volume of gas a pipeline must transport to a customer to qualify as transmission. Volumes vary, and setting an arbitrary threshold might unfairly reclassify some existing lines. However, since ''large volume customer'' and ''distribution center'' each mark the end of transmission under the definition, operators may use the volume of gas supplied to distribution centers as a guide to identifying large volume customers.

The NAPSR report recommended changing the part 192 definition of ''transmission line'' so that pipelines beginning at gathering or transmission lines and ending at ''distribution systems and other load centers'' would be classified as transmission lines. Under this alternative wording, load centers conceivably would include large volume customers.

Most of the persons who commented directly on this NAPSR recommendation opposed it. A primary objection was that the recommended definition would needlessly reclassify as transmission low stress pipelines between communities or between distribution systems and high pressure transmission lines. In this regard, many commenters felt transmission should be limited to pipelines that operate at 20 percent or more of specified minimum yield strength (SMYS) of pipe, one of the characteristics under the present definition. The lack of definition of the term ''load center'' was another frequently stated reason for opposing the NAPSR recommendation. Commenters argued that introducing this term into the definition would lead to more, not less, confusion. Also several commenters thought the definition of transmission line should remain unchanged until RSPA completes its project to redefine the term ''gathering line,'' which appears in the transmission line definition. After considering these concerns, we agree that the NAPSR recommendation would not strengthen the present definition and could cause reclassification of many lines. Therefore, we did not adopt the recommendation in the final definition.

Section 192.5, Class Locations

RSPA proposed to clarify § 192.5 to minimize the possibility that a pipeline is classified higher than required. Inasmuch as part 192 regulations become more stringent as pipeline classification increases, any over-classification results in needless expenditures.

Fourteen TPSSC members voted for the proposal and one abstained. Eight operators and one pipeline-related association commented on the proposed change. While these commenters generally supported the need to clarify § 192.5, two operators suggested alternative wording. Based on one suggestion, RSPA has combined proposed §§ 192.5 (c)(2) and (c)(3) into final § 192.5(c)(2).

One focus of the NPRM was the cluster exception in existing §§ 192.5(f)(2) and (f)(3). This exception provides that if a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the classification ends 220 yards from the nearest building in the cluster, rather than at the end of the 1-mile class location unit that would otherwise be the basis for classification. In the NPRM (at 39573), we stated that adding buildings outside a cluster to those inside the cluster would result in over-classification of the class location unit. However, this statement was incorrect. The history of § 192.5 (35 FR 13251, August 19, 1970) shows that the cluster exception applies only when all buildings in a 1-mile class location unit are in a single cluster. If a class location unit contains buildings outside a cluster or more than one cluster of buildings, all buildings in the unit must be counted to determine the classification of the unit. The final rule clarifies this point.

The association that commented thought we should define the term ''cluster.'' However, the term is used in its ordinary dictionary sense, and, in RSPA's experience, has not been a significant source of misunderstanding.

Section 192.7, Incorporation by Reference

Section 192.7 describes the incorporation by reference in part 192 of documents or portions of documents relevant to gas pipeline safety. RSPA proposed to revise § 192.7(a) to clarify that when a regulation in part 192 references a document, the entire document is not necessarily incorporated by reference. Rather, only those portions of the document that are specifically referenced in the regulation or are essential for compliance with the regulation are incorporated by reference. Such portions may or may not comprise the whole document, depending on the scope of the reference.

Fourteen TPSSC members voted for the proposal and one abstained. Commenters on the proposed change, seven operators and one pipeline-related association, all favored the proposal. However, two of these commenters wanted RSPA to change the rule in a manner not proposed. They advised changing § 192.7 to require operators to follow the latest published editions of documents, instead of particular editions, which can become obsolete before RSPA updates the references. RSPA believes this recommended action is inappropriate because it would hand over an established governmental function, rulemaking, to the private organizations who produce the referenced documents. Each newly published edition would automatically change a pipeline safety rule and bypass the Federal rulemaking process, which ensures fair treatment of all affected parties.

Section 192.9, Gathering Lines

When the NPRM was published, § 192.9 required gathering lines to comply with part 192 standards applicable to transmission lines without indicating that certain gathering lines are excepted from part 192 by § 192.1. To highlight this exception and provide a clear understanding of which gathering lines must meet transmission line standards, we proposed to cross-reference § 192.1 in § 192.9.

Thirteen TPSSC members voted for the proposal and two abstained. RSPA received seven comments on the proposed change, six from operators and one from a pipeline-related association. Only one commenter opposed the proposal, saying it did not see how the change would clarify the present rule.

Then in 1994, in a separate, unrelated action concerning the passage of pigs, RSPA revised § 192.9 to include a cross-reference to § 192.1 (59 FR 17281, April 12, 1994). Thus, § 192.9 has already been changed consistent with the proposal in this proceeding, and no further action is necessary.

Section 192.11, Petroleum Gas Systems (Including Changes to §§ 192.1 and 192.3)

RSPA proposed several changes to the special rules in § 192.11 for petroleum gas systems: First, we proposed to require that peak shaving plants supplying petroleum gas by pipeline to a natural gas distribution system as well as pipeline systems transporting only petroleum gas or petroleum gas/air mixtures comply with part 192 standards and the National Fire Protection Association (NFPA) Standards 58 and 59. Downstream from the point where a peak shaving plant injects petroleum gas into a natural gas distribution system, only part 192 would apply. Next, we proposed that the NFPA Standards prevail in the event of a conflict between part 192 and NFPA Standards 58 or 59. At the same time, we said that a conflict does not exist when NFPA Standards 58 and 59 are silent or nonspecific on a subject (such as for corrosion protection or leak detection). In this case, the operator would have to comply with any applicable part 192 rule. Finally, we proposed to add a definition of ‘‘petroleum gas’’ to § 192.3, and to clarify under § 192.1(b)(4) which petroleum gas systems are excepted from part 192.

Ten TPSSC members voted for the proposal, one member supported it with a recommended change, three members opposed it, and one abstained. Two TPSSC members disagreed with the proposal that NFPA standards should prevail in the event of a conflict with part 192. One TPSSC member voted yes, but recommended that in the event of conflict the most stringent requirement should prevail.

We explained in the NPRM why we believe the NFPA standards should have priority in direct conflict situations. The main reason is that in contrast to part 192, the NFPA Standards specifically cover petroleum gas transportation. Also, NFPA Standards 58 and 59 reflect current petroleum gas technology and safety practices. Given this special attention to petroleum gas, we do not think there is sufficient reason to require operators to follow part 192 instead of the NFPA Standards in the event of conflict, even if part 192 is more stringent.

RSPA received eight comments in favor and three comments in opposition to the proposed changes to § 192.11. Those commenters who opposed the proposal were concerned that compliance with NFPA Standards 58 and 59 would involve significant capital expenditures. However, § 192.11 already requires petroleum gas systems to meet NFPA Standards 58 and 59. And, in accordance with 49 U.S.C. § 60104(b), none of the design, installation, construction, initial testing, or initial inspection requirements of NFPA Standards 58 and 59 would apply under part 192 to peak shaving plants now in existence. So, retrofitting existing plants would not be required. Although all plants would have to comply with the operation and maintenance requirements of NFPA Standards 58 and 59, overall compliance costs should be small because, as NFPA stated in its petition, most, if not all, existing plants already comply with NFPA Standards 58 and 59 to qualify for insurance coverage. Thus, § 192.11 is revised as proposed in the NPRM.

Proposed § 192.1(b)(4)(i) would exclude from part 192 pipeline systems that transport only petroleum gas or petroleum gas/air mixtures to fewer than 10 customers, if no portion of the system is located in a public place. This exclusion is in the present § 192.11(a), but in proposing to relocate it to § 192.1(b)(4)(i), we omitted the parenthetical phrase ‘‘(such as a highway).’’ One commenter objected to the omission, saying it would leave the meaning of ‘‘public place’’ open to interpretation. However, our experience has been that the parenthetical phrase has hindered more than helped the understanding of public place. We have consistently interpreted ‘‘public place’’ to mean a place which is generally open to all persons in a community as opposed to being restricted to specific persons. We consider churches, schools, and commercial property as well as any publicly owned right-of-way or property which is frequented by persons to be public places. Although § 192.11(a) refers to a highway as an example of a public place, many operators have incorrectly considered the example to restrict, rather than define, the coverage of petroleum gas systems with fewer than 10 customers.

Proposed § 192.1(b)(4)(ii) would clarify that part 192 does not apply to single-tank, single-customer petroleum gas systems located entirely on the customer's premises, but partially in a public place. These systems exist, for example, at churches or restaurants, where the gas is used for heating or cooking. The proposal was based on the jurisdiction of part 192 over the distribution of gas. As indicated by the definition of ‘‘service line’’ (§ 192.3), part 192 does not apply to gas distribution beyond the point where metered gas enters customer piping. For single-tank, single-customer systems on the customer's premises, this point normally occurs at the tank.

Three commenters protested that part 192 would still apply to single-customer, multi-tank systems on the customer's premises, regardless of tank size. For example, the proposed rule would not exclude a two-tank system partly in a public place, even if the total quantity of stored gas is less than in a large single-tank system. Because the proposed exclusion did not rest on the quantity of gas delivered to the customer, we agree that the number of tanks should not be a factor in the exclusion of single-customer systems on the customer's premises. Therefore, final § 192.1(b)(4)(ii) omits the term ''single-tank.''

The proposed definition of ''petroleum gas'' drew no objections from either the TPSSC or commenters. So the definition is adopted as proposed.

Sections 192.14 and 192.553, Conversion and Uprating

If a steel pipeline to be converted to gas service under part 192 has not been designed and constructed to meet part 192 standards, it must be converted according to § 192.14 (§ 192.13(a)(2)). Section 192.14(a)(4) requires that each pipeline must be pressure tested under subpart J of part 192 to substantiate the maximum allowable operating pressure (MAOP) permitted by subpart L of part 192. Under subpart L, to compute the MAOP of a pipeline being converted, an operator must determine the design pressure of the weakest element of the pipeline (§ 192.619(a)(1)).

Design pressure is also a factor under § 192.553, which establishes general requirements for increasing any pipeline's MAOP (uprating). Under § 192.553(d), an increased maximum allowable operating pressure may not exceed the MAOP part 192 allows for a new pipeline constructed of the same materials in the same location. Thus, to uprate a pipeline within this MAOP limit, an operator must determine the design pressure of the weakest element of the pipeline (§ 192.619(a)(1)).

Because of the role of design pressure, a steel pipeline may not be converted or uprated when any of the pipe characteristics needed to calculate design pressure under § 192.105 is unknown. Therefore, RSPA proposed to amend §§ 192.14(a)(1) and 192.553(d) to permit the conversion or uprating of steel pipelines based on an approach found in paragraph 845.214 and Appendix N of the ASME B31.8 Code. Under the proposal, when design pressure is unknown, operators would have to pressure test the pipeline under Appendix N until pipe yield occurs. The first pressure that produces pipe yield, reduced by 20 percent and the appropriate factor under § 192.619(a)(2)(ii), would be used instead of design pressure to calculate MAOP.

Twelve TPSSC members voted for the proposed revision of § 192.14, one member supported it with a recommended change, one member opposed it but suggested changes, and one member abstained. Eleven members voted for the proposal regarding § 192.553, two supported it with a recommended change, one opposed it, and one abstained. The recommended changes were to make yield testing mandatory instead of permissive, and to allow yield testing that is based on other than the ''first pressure'' that produces yield, since Appendix N does not use that term. The reasons against the proposal were that yield testing appeared to be mandatory, and use of the Appendix N method should be discretionary.

RSPA has adopted the recommended change regarding mandatory yield testing. Although, in the proposed rules, yield testing may have appeared permissive, RSPA clearly intended such testing to be the only alternative when design pressure is unknown. Therefore, in the final rule, if factors in the design formula are unknown, a pipeline to be converted or uprated would have to be pressure tested under Appendix N to determine pipe yield, except as discussed below for low-stress pipe.

The TPSSC member's recommendation to delete ''first pressure'' from the proposed rule was not adopted. Although Appendix N does not refer to the first pressure that produces yield, paragraph 845.214(a)(2) of the ASME B31.8 Code, which applies to the establishment of MAOP when design pressure is unknown, provides that only the first test to yield can be used to determine MAOP. The proposed rules were consistent with this B31.8 standard, which precludes the use of higher yield pressures that can result from successive testing.

RSPA did not adopt the TPSSC member's comment that use of the Appendix N method should be discretionary. When MAOP is determined without knowing the pipeline's design pressure, conformity to a standardized practice (Section N5.0 of Appendix N) assures additional safety to offset the lack of knowledge about design pressure.

RSPA received comments on the proposed rules from 11 operators and three pipeline-related associations. Four operators and one pipeline-related association recommended removal of the proposed requirement to use the ''first pressure'' that produces yield. Our position on this subject is given above in response to a similar comment by a TPSSC member.

One operator and one pipeline-related association suggested locating the proposed amendments in § 192.105 instead of §§ 192.14 and 192.553. RSPA did not adopt this suggestion because § 192.105 affects the design of new pipelines, a subject the proposed rules did not address.

One operator and two pipeline-related associations argued that pressure testing to yield is unnecessary to qualify low-stress distribution lines (generally lines 12¾ inches or less in nominal outside diameter operating at pressures less than 200 psig) for conversion or uprating. Part 192 recognizes that low-stress pipelines present a much lower risk to public safety than high-stress lines, all other factors being equal. For example, certain welding standards in subpart E are less stringent for pipelines to be operated below 20 percent of SMYS. Because of the lower risk, the final rule provides that pipelines 12¾ inches or less in nominal outside diameter to be operated at a pressure less than 200 psig may be converted or uprated without testing to yield. The MAOP of such pipelines may be determined under § 192.619(a)(1) by using 200 psig as design pressure.

An operator argued that pressure testing to yield should be discretionary, because sufficient safety would be provided by the proposed pressure reduction factors regardless of the level of test pressure. The commenter was also concerned that pressure testing to yield for an extended time could cause the growth of defects that later cause failure during operation. Two hours was suggested as the optimum hold time for yield testing, based on ongoing studies.

RSPA did not adopt these comments. Pressure testing to yield exposes more material and construction defects than does testing to a lower pressure. With fewer defects remaining after testing to yield, greater long-term protection against failures due to the growth of unexposed defects results. RSPA intended this extra protection, combined with the proposed pressure reduction factors, to offset the absence of design pressure as a limit on MAOP. Pressure testing to yield appears to be reasonable since many operators already strength test their pipelines at or above yield for safety and efficiency reasons. Also, none of the other commenters or TPSSC members objected to pressure testing to yield, except as discussed above for low-stress lines. As to the optimum hold period for yield testing, because the matter is still being studied by industry and is not addressed by the procedure for yield testing under Appendix N, it is too soon to consider establishing a special hold period for yield testing under part 192.

The final rules have been drafted to improve clarity, to show their relation to design pressure and MAOP under § 192.619, and to include the changes discussed above. The proposed amendments to §§ 192.14(a)(1) and 192.553(d) are revised and published as an amendment to § 192.619(a)(1), because this section deals specifically with design pressure and MAOP. Final § 192.619(a)(1), set forth below, provides that when design pressure is unknown for steel pipelines being converted or uprated, a reduced value of first yield hydrostatic test pressure, instead of design pressure, is used to compute MAOP. As discussed below, final § 192.619(a)(1) does not include the reduction factors proposed for butt and lap welded pipe under § 192.14(a)(1)(ii). If the pipeline to be converted is 12¾ inches or less in nominal outside diameter, 200 psig, instead of design pressure, may be used if the line is not yield tested. Section 192.553(d) is also revised to refer to amended § 192.619(a)(1). Also, because the 1992 edition of the ASME B31.8 Code is now out-of-print, the 1995 edition is referenced in § 192.619(a)(1) as shown by the revisions to Appendix A of part 192 (see below).

Section 192.107, Yield Strength (S) for Steel Pipe

For pipe made according to a specification not listed in part 192 or whose specification or tensile properties are unknown, § 192.107(b)(1) provides that yield strength may be established by tensile testing in accordance with section II–D of appendix B to part 192. When yield strength is determined by such tensile testing, paragraph (b)(1) requires that the yield strength used in the design formula of § 192.105 be the lower of either 80 percent of the average yield strength determined by tensile testing or the lowest yield strength determined by tensile testing, but not over 52,000 psi. RSPA proposed to remove this 52,000 psi upper limit on yield strength, because higher strength pipe has become available since this limitation was adopted, and tensile testing is a generally accepted method of determining material properties.

Twelve TPSSC members voted for the proposal, one member supported it with a recommended change and two abstained. The member recommending the change felt that the proposal would be better justified if we knew the proportion of higher strength pipe that lacks tensile documentation and why this information is unknown. RSPA believes this information is not essential in deciding whether to adopt the proposal because the proposed amendment has limited application. We expect operators would use the proposed amendment to qualify stock pipe they have stored for maintenance and emergencies and to qualify used pipe being reclaimed. In either case, the amount of pipe that would be qualified under proposed § 192.107(b)(1)(ii) should be very small compared with all pipe being qualified for use in gas pipeline systems.

RSPA received six comments on the proposed amendment. The comments came from five operators and one pipeline-related association, and all supported the proposal. In addition, one operator recommended that RSPA further amend § 192.107 to permit the use of recognized statistical methods to determine yield strength from tensile tests. RSPA did not adopt this comment because this concept was not addressed in the NPRM and would require further public comment and study.

Accordingly, § 192.107 is amended as proposed in the NPRM.

Section 192.121, Design of Plastic Pipe

RSPA proposed to add the following formula to § 192.121, which would allow use of the Standard Dimension Ratio (SDR) in determining design pressure for plastic pipe:

$$P = \frac{2S}{(SDR-1)} 0.32$$

SDR is a commonly used plastic pipe characteristic in the gas pipeline industry.

Thirteen TPSSC members voted for the proposal and two abstained. RSPA received eight responses from the public, all in favor of the proposed rule. Therefore, the final rule is issued as proposed in the NPRM, except that the proposed definition is reworded to conform to standard usage. The final definition agrees with the SDR definition given in the voluntary standard referenced in part 192 for the manufacture of thermoplastic pipe: American Society for Testing and Materials (ASTM) Designation D 2513, ‘‘Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings’’ (1990c edition).

Section 192.123, Design Limitations for Plastic Pipe

Under § 192.123, plastic pipe may not be used where pipe operating temperatures are below −20°F. RSPA proposed to lower this limit to −40°F in light of improvements in pipe technology. Additionally, RSPA proposed to clarify § 192.123(b)(2), which sets the maximum operating temperature for thermoplastic pipe and reinforced thermosetting plastic pipe.

Thirteen TPSSC members voted for the proposal and two abstained. RSPA received nine comments on the proposed rule changes: six from operators, one from a pipeline-related association, and two from manufacturers. The operators and the association supported the proposal or did not object to it. However, the manufacturers opposed the proposal stating that many components other than pipe that are made for use in gas pipeline systems do not have a low temperature rating of −40°F, although they perform satisfactorily at −20°F. One of these commenters argued that unsafe operation could occur if pipeline designers assumed that all components, such as repair and connection devices, fittings, valves, meters, and regulators, may be used at −40°F.

RSPA shares the manufacturers' concern. Therefore, the final rule allows the use of plastic pipe at temperatures between −20°F and −40°F only if all pipe and pipeline components whose operating temperature will be below −20°F have a manufacturer's temperature rating consistent with that operating temperature.

Section 192.179, Transmission Line Valves

Gas transmission lines must have sectionalizing block valves spaced according to population density under § 192.179(a). RSPA proposed to revise this rule to allow the RSPA Administrator to approve alternative spacing where the operator demonstrates an equivalent level of pipeline safety.

Thirteen TPSSC members voted for the proposal, one against, and one abstained.

RSPA received comments from 12 operators, two pipeline-related associations, and a state agency. Thirteen commenters gave their full or qualified approval, but one association and the state agency argued against the proposal. Those commenters expressing qualified support generally felt that the proposal offered some benefit to pipeline operators. However, they urged that operators be permitted to determine spacing based on criteria similar to those for hazardous liquid pipelines in 49 CFR 195.260(c).

RSPA did not adopt the comment that transmission line valve spacing should be governed by criteria similar to those in 49 CFR 195.260(c). While those criteria may be appropriate for hazardous liquid pipelines, we have no indication they are suitable for gas transmission lines. In fact, the widely accepted voluntary standard for valve spacing, paragraph 846.11 of the ASME B31.8 Code, differs little from existing § 192.179.

As for the comments opposing the proposal, RSPA has considered the state agency's concern that the proposed rule would infringe on the authority of state agencies to grant waivers from § 192.179 for intrastate transmission lines. (See 49 U.S.C 60118(d)). However, this concern has been addressed by a procedural rule (49 CFR 190.9) that RSPA adopted to handle petitions for finding or approval under the federal pipeline safety regulations. Under this rule, which would apply to petitions for alternative spacing under § 192.179, operators of intrastate pipelines subject to the safety regulatory jurisdiction of a certified state agency must submit their petitions to that agency for review and recommendation before final action by the Administrator.

RSPA does not agree with the pipeline-related association's suggestion that since the underlying rule is not justified, the proposed amendment is not needed. The basis for existing § 192.179 was the 1968 edition of the ASME B31.8 Code. As noted above, the current edition of that code continues to specify valve spacing similar to § 192.179.

Section 192.203, Instrument, Control, and Sampling Pipe and Components

Under § 192.203(b)(2), each takeoff line must have a shutoff valve as near as practicable to the point of takeoff. RSPA proposed an exception for takeoff lines on pressure regulators when the lines can be isolated by other valves from their source of pressure.

Eleven TPSSC members voted for the proposal, one voted against it, two members supported it with a recommended change, and one abstained. The two members recommended that we also except instrument control lines that are capable of being isolated from their source of pressure.

Although the industry's use of isolatable regulators gave rise to the proposed rule change, isolation of a takeoff line from its pressure sources applies to any takeoff line capable of such isolation, not just takeoff lines on regulators. Therefore, the final rule excepts any takeoff line capable of being isolated from its sources of pressure. Thus, the term ''takeoff line'' includes instrument control lines that are designed as takeoff lines.

RSPA received 13 public comments, all in favor of changing the regulation. One of these commenters offered a rewording intended to broaden the regulation to include control lines at both measuring and regulating stations. As explained above, such control lines will be covered by the exception when they are takeoff lines capable of isolation from their sources of pressure.

Section 192.227, Qualification of Welders, and § 192.229, Limitations on Welders

Welders qualified to weld on pipe to be operated at any hoop stress (§ 192.227(a)) must requalify every 6 months (§ 192.229(c)). However, welders qualified to weld only on pipe to be operated at low hoop stress (less than 20 percent of SMYS) need only requalify once a year (§ 192.227(b)), and the requalification requirements are less comprehensive than those for other welders.

RSPA proposed to revise §§ 192.227 and 192.229 to allow welders initially qualified for any hoop stress level, but who weld only on pipe to be operated at low hoop stress, to requalify under the low-stress requirements. Such welders would then not be permitted to weld on pipe to be operated at 20 percent or more of SMYS unless they again qualify under § 192.227(a).

Twelve TPSSC members voted for and one against the proposed revision of § 192.227, and two abstained. The TPSSC members' vote on § 192.229 was the same as on § 192.227. Eight pipeline operators and two pipeline-related associations also agreed with the proposal.

A commenter suggested that the final rule make clear that either existing § 192.229(c) or § 192.227(b) can be used to requalify welders to weld on pipe to be operated at less than 20 percent of SMYS. RSPA adopted the substance of this comment by adding a sentence concerning low stress requalification to the final § 192.229(c).

The commenter who opposed the proposal claimed that qualification under §§ 192.227(a) and (b) is inadequate. However, RSPA finds no justification for this claim. Section 192.227 became effective in February 1970. Our accident data in the intervening 26 years have not indicated that field welding of steel materials in pipelines presents a significant safety problem.

In the final rules, proposed § 192.227(c) is redesignated as § 192.229(d). Thus, all requalification requirements appear in one section.

Section 192.241, Inspection and Test of Welds

Section 192.241 requires inspection and test of welds on steel materials in pipelines, except welds made during the manufacture of pipe and pipeline components. Under existing § 192.241(c) and appendix A to part 192, the acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 6 of API Standard 1104 (17th edition).

The Appendix of API Standard 1104, which is based on fracture mechanics principles, provides more detailed acceptance standards for weld flaws than the criteria in section 6 of API Standard 1104. RSPA proposed to amend § 192.241(c) to permit use of the Appendix as an alternative acceptance standard for girth weld flaws, except welds unacceptable because of a crack.

Eleven TPSSC members voted for the proposal, three members supported it with a recommended change and one abstained. The three members suggested that the word ''flaw'' be changed to ''defect''.

In existing § 192.241, neither the word ''flaw'' nor ''defect'' is used. The rule is written in terms of weld acceptability. Therefore, in response to the comments of the TPSSC members, the final rule is written without using either ''flaw'' or ''defect.''

Eleven pipeline operators and three pipeline-related associations agreed with the proposed change. Only one commenter was opposed to allowing use of the Appendix of API Standard 1104. This commenter was concerned that industry inspection personnel may not be qualified to apply the complicated engineering criteria found in the Appendix. On the contrary, personnel who would use the Appendix must be able to apply it correctly. Under §§ 192.243(b) and (c), operators must ensure that nondestructive testing is performed in accordance with written procedures by persons who have been properly trained and qualified.

The final rule indicates that use of the Appendix is restricted to girth welds to which the Appendix applies. For example, as Section A.1 of the Appendix provides, welds used to connect fittings and valves are not covered. Also, the Appendix applies only to girth welds between pipe of equal nominal wall thickness.

Section 192.243, Nondestructive Testing

For pipelines subject to nondestructive testing under part 192, § 192.243(d)(4) requires such testing for all field butt welds at pipeline tie-ins. RSPA proposed to amend § 192.243(d)(4) to add the phrase ''including tie-ins of replacement sections.'' This change was meant to clarify that tie-ins occur in pipeline replacement, as well as in new construction.

Fourteen TPSSC members voted for the proposal and one abstained.

Comments were received from five pipeline operators and one pipeline-related association, and all favored the proposed rule change. Section 192.243 is amended as proposed in the NPRM.

Section 192.281, Plastic Pipe

This rule establishes standards governing the joining of plastic pipe. RSPA proposed to revise § 192.281(c), which applies to heat-fusion joints, to cover electrofusion, a method of heat-fusion joining. The proposal was that electrofusion joints must be made with equipment and techniques expressly prescribed by the fittings manufacturer.

Thirteen TPSSC members voted for the proposal, one member supported it with a recommended change, and one abstained. The recommended change was that ''or the equivalent'' be added so that operators could use equipment and techniques equivalent to that prescribed by fittings manufacturers.

RSPA received 15 comments on the proposed change to § 192.281(c). Eleven commenters fully or partially agreed with the proposed rule, while four commenters objected. A commenter who partially agreed recommended that electrofusion be specifically addressed in § 192.285. However, RSPA finds that step unnecessary because electrofusion is a type of heat fusion, and heat fusion is covered by § 192.285(b)(2).

The objections focused on RSPA's proposal that operators must use ''equipment and techniques expressly prescribed by the fittings manufacturer.'' One commenter said that electrofusion equipment is expensive and that most electrofusion fittings can be installed only by using the fittings manufacturer's equipment. As a result, most operators have only a single source of electrofusion fittings. However, the commenter stated that electrofusion equipment under development will allow the installation of several different brands of electrofusion fittings, and that those additional sources would encourage competitive pricing. Other operators argued they should not be denied the use of procedures and equipment not expressly prescribed by the fittings manufacturer, as long as the procedures are qualified for use under § 192.283.

Since the proposal was intended to relax the current regulatory requirement, RSPA accepts the recommendations that operators should have latitude in choosing equipment and techniques for use in electrofusion joining. We have adopted a slight revision of the wording proposed by three pipeline operators and one pipeline-related association. This wording meets the ''or the equivalent'' recommendation made by the TPSSC member. Additionally, this wording responds to the commenter's concern that the proposed wording would deter competitive pricing. The adopted wording requires that the joints be joined using equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing to certain criteria of ASTM Designation F1055, ''Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing,'' to be at least equivalent to those of the fittings manufacturer. The ASTM criteria are those adopted under the next heading for qualifying electrofusion joining procedures.

Section 192.283, Plastic Pipe: Qualifying Joining Procedures

Section 192.283 prescribes criteria for qualifying procedures used to join plastic pipe. RSPA proposed to amend this section by adding more appropriate criteria for procedures used to join polyethylene plastic pipe by electrofusion. The proposed criteria are contained in certain sections of ASTM Designation F1055 (1987 edition).

Fourteen TPSSC members voted for the proposal and one member abstained.

RSPA received eight comments on the proposal: seven from pipeline operators and one from a pipeline-related association. Seven commenters supported the proposal. But one opposed it, saying that the proposal should be withdrawn or rewritten to accept any procedure that demonstrates a suitable quality of joint. We believe, however, that allowing operators to judge the quality of an electrofusion joint without applying a recognized safety standard would be unacceptable. Because of the failure risk of plastic pipe joints, the present rule requires heat fusion joining methods to be qualified under generally recognized voluntary standards, ASTM D2513 and ASTM D2517. In the absence of safety data to the contrary, as a heat fusion method, electrofusion procedures should likewise be qualified under an appropriate recognized standard. Accordingly, proposed § 192.283(a)(iii) is adopted as final. However, the proposed reference to the 1987 edition of ASTM Designation F1055 is updated to the 1995 edition, as shown by the revisions to Appendix A of part 192 (see below). And the referenced title of paragraph 9.4 is corrected to read ''Joint Integrity Tests.''

Sections 192.317(a), Protection From Hazards

This section requires that gas transmission lines and mains be protected from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or sustain abnormal loads. Additionally, offshore pipelines must be protected from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations. RSPA recognized that in areas susceptible to these hazards, such as offshore pipelines in areas where hurricanes usually pass, complete protection against the hazards may not be feasible. We, therefore, proposed to change the regulation to require that in construction of transmission lines and mains, operators ''take all practicable steps to protect'' the pipeline against the cited hazards.

Eleven TPSSC members voted for the proposal, one member supported it with a recommended change, two members were opposed and one member abstained. The two members who opposed it said that ''all practicable steps to protect'' would be difficult to interpret.

Comments were received from seven pipeline operators and two pipeline-related associations. All commenters gave their full or qualified approval.

RSPA has issued the final rule as proposed in the NPRM. The ''all practicable steps to protect'' wording was left in the rule to allow operators flexibility in compliance; any tightening of this performance wording would diminish that flexibility. RSPA will interpret or apply the rule in light of customary pipeline design and construction practices in the industry.

§§ 192.319(c) and 192.327(e), Offshore Pipe in the Gulf of Mexico and Its Inlets

Under § 192.612, operators had to inspect gas pipelines in the Gulf of Mexico and its inlets in waters up to 15 feet deep. If the pipelines were found exposed or to be a hazard to navigation (i.e., buried less than 12 inches below the seabed), the operator had to bury them to a depth of 36 inches in soil or 18 inches in rock.

The part 192 review disclosed that §§ 192.319(c) and 192.327(e), which govern the installation of pipe offshore, are incompatible with the objectives of § 192.612. In water between 12 and 200 feet deep, § 192.319(c) permits pipe to be installed at or above the natural bottom. And in water less than 12 feet deep, in certain circumstances § 192.327(e) permits pipe to be buried less than 36 inches in soil or 18 inches in rock. RSPA proposed to amend §§ 192.319(c) and 192.327(e) to require that when pipe is installed offshore in the Gulf of Mexico and its inlets, the pipe must be installed consistent with the burial standards of § 192.612.

Thirteen TPSSC members voted for the proposal, one member supported it with a recommended change, and one abstained. One member supported the proposal but recommended rewording and rearrangement for clarity, and that § 192.319(c) be moved to § 192.327.

Seven operators and four pipeline-related associations supported the proposed changes to §§ 192.319(c) and 192.327(e). However, five commenters recommended wording changes and rearrangement for clarity, and five commenters suggested that § 192.319(c) be moved to § 192.327. In light of the recommendations, RSPA has clarified the final rule text, as set forth below.

One pipeline-related association opposed the proposal. It maintained that pipe installed in water between 12 and 15 feet deep with less than 12 inches of cover (now acceptable under § 192.319(c) but not § 192.612) might not be an actual hazard to navigation. But the proposal concerned the inconsistency of § 192.612 with other pipeline safety rules, a problem that can be resolved without reopening the question of what is a ''hazard to navigation'' in the Gulf of Mexico and its inlets. A ''hazard to navigation'' is defined in § 192.3 to mean ''a pipeline where the top of the pipe is less than 12 inches below the seabed in water less than 15 feet deep, as measured from the mean low water.'' This definition was adopted in the proceeding on § 192.612 (Docket No. PS–120). Any remaining controversy over the definition may be raised by submitting a petition for rulemaking under 49 CFR part 106.

Section 192.321, Installation of Plastic Pipe; and § 192.375, Service Lines: Plastic

Section 192.321(a) requires that plastic pipe be installed below ground level. RSPA proposed to allow the temporary use of uncased (i.e., not encased) plastic pipe above ground level under certain conditions. The proposed conditions limited the use to (1) 30 days; (2) locations where the pipe is unlikely to be damaged (or is protected from damage) by external forces; (3) pipe that is resistant to the exposure to ultraviolet light and temperature extremes; and (4) pipe that has not been previously used above ground level.

Nine TPSSC members voted for the proposal, one against, three members supported it with a recommended change, and two abstained. The recommended changes were similar to those made by the commenters as discussed below.

RSPA received 18 comments on this proposal. Each commenter agreed partially with the proposed rule. Some commenters said the current rule should be amended to permit the permanent use of plastic above ground when the pipe is encased in steel conduit. However, since the proposal concerned only temporary usage, this comment was not adopted in the final rule.

Many commenters argued that the 30-day period would be too brief. They suggested a longer period, such as 60 or 90 days, in view of the time it may take to complete a permanent installation. They cited the time associated with planning, obtaining governmental permits, acquiring easements, engaging contractors, competing work demands, and other unforeseen events. Several commenters suggested that no specific time limit be defined and that performance language be used.

Commenters also maintained that the proposed prohibition against the subsequent reuse of plastic pipe above ground level is not justified, since commercially available plastic pipe can be exposed to ultraviolet light for at least 2 years with no degradation of its properties. These commenters argued that the rule should permit reuse of plastic pipe provided such use does not exceed the pipe manufacturer's exposure limits.

RSPA agrees that in most cases 30 days may not be enough time for operators to take full advantage of a temporary aboveground plastic pipe installation. In a recent waiver of § 192.321(a), we allowed the applicant to install plastic pipe above ground for a time that does not exceed the manufacturer's recommended maximum period of exposure (60 FR 55752; Nov. 2, 1995). Although commenters indicated that extending the limit to 2 years might not adversely affect pipeline safety, we are not certain 2 years would be safe for all plastic materials. Some pipe manufacturers may recommend less exposure time. Therefore, we have chosen the manufacturer's recommended maximum period of exposure but not longer than 2 years as the limit on the temporary use of plastic pipe above ground. If a manufacturer has no recommended maximum exposure period, then the limit would be 2 years. RSPA does not believe a performance standard would provide a suitable time limit, because the safe service life of plastic pipe exposed above ground is too uncertain.

RSPA agrees that the final rule should not unduly hinder the use of plastic pipe. Thus, the proposed ban on reusing plastic pipe above ground level does not appear justified. The final rule permits cumulative aboveground use for the manufacturer's recommended maximum period of exposure but not longer than 2 years, provided the operator can demonstrate the cumulative time of aboveground use. In monitoring compliance, RSPA will consider credible evidence that demonstrates cumulative time of use, such as business records, work orders, or affidavits related to the pipe concerned.

RSPA recognized that the changes to § 192.321 affected only plastic mains and transmission lines. However, the need for these changes applies as well to plastic service lines. As with transmission lines and mains, in some situations operators may be able to save material and construction costs of service lines located outside buildings by temporarily installing the lines above ground. Thus, § 192.375(a), which requires that plastic service lines outside buildings be installed below ground, is revised to allow temporary aboveground installations in accordance with § 192.321(g).

Section 192.455, External Corrosion Control: Buried or Submerged Pipelines Installed After July 31, 1971

Under § 192.455(a)(2), a pipeline must have a cathodic protection system designed to protect the pipeline in its entirety. RSPA proposed to remove the phrase ''in its entirety'' because it is unnecessary to convey the meaning of the rule, and some operators have incorrectly assumed that pipeline casings also must be protected.

In addition, § 192.455(f)(1) exempts from corrosion control requirements certain metal fittings in plastic pipelines if the fitting is protected against corrosion by alloyage. RSPA recognized that the word ''alloyage'' is not in common usage and proposed its replacement with ''alloy composition'' to improve understanding.

Twelve TPSSC members voted for the proposal, two members supported it with a recommended change and one abstained. The two members recommended that in proposed paragraph (f)(1), the term ''corrosion resistance'' be replaced by ''corrosion control,'' which is the term used in the existing rule and throughout subpart I. RSPA has made this replacement in the final rule.

Comments were received from six pipeline operators and one pipeline-related association. Six commenters gave their full approval and the seventh was noncommittal. Therefore, except for the previously discussed wording changes, § 192.455 is adopted as proposed in the NPRM.

Section 192.475, Internal Corrosion Control: General.

Section 192.475(c) limits the hydrogen sulfide content of natural gas stored in pipe-type or bottle-type holders to 0.1 grain per 100 standard cubic feet of gas. An operator proposed that this rule be relaxed to allow a concentration of 0.25 grain per 100 standard cubic feet of gas. Because the 0.25 limit is within customary industry contract limits and is still lower than maximum allowable safe limits set by other government agencies, RSPA proposed to increase the allowable hydrogen sulfide limit in gas to be stored in pipe-type and bottle-type holders to 0.25 grain per 100 standard cubic feet of gas. This action would lower the cost of processing natural gas that contains small quantities of hydrogen sulfide.

Thirteen TPSSC members voted for the proposal, one against, and one member abstained.

Seven commenters supported the proposed change. No commenters opposed the change. One state agency suggested that hydrogen sulfide levels be expressed in parts per million in addition to grains per 100 standard cubic feet of gas. The NAPSR report also made this recommendation, and all comments on the subject were supportive. RSPA agrees the allowable level should be stated in parts per million and has included this designation in the final rule.

Section 192.485, Remedial Measures: Transmission Lines

RSPA's review of § 192.485, which prescribes remedial measures for corroded transmission lines, disclosed that many operators need guidance on how to determine the remaining strength of corroded pipe. RSPA proposed to provide this guidance by referencing ASME B31G Manual for Determining the Remaining Strength of Corroded Pipelines in a new § 192.485(c).

Fourteen TPSSC members voted for the proposal and one member abstained.

Comments relevant to proposed § 192.485(c) were received from 10 pipeline operators and two pipeline-related associations. Six commenters gave their full or partial support. Another six said the proposal was unnecessarily restrictive because it did not allow the use of other proven industry-developed methods for determining the remaining strength of corroded pipelines.

The most noteworthy method mentioned was the method in the American Gas Association (AGA) report for Project PR 3–805, ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,'' (December 22, 1989; AGA catalog No. L51609). Project PR 3–805 was undertaken to devise a criterion that, while still assuring adequate pipeline integrity, would eliminate, as much as possible, the excess conservatism embodied in the ASME B31G Manual. For a complex analysis, the modified criterion can be applied by using a computer program called RSTRENG, which is furnished with the report. The modified criterion can also be applied with a long-hand equation, or if a simplified analysis is preferred, with tables or curves.

Evaluating the strength of corroded pipe by procedures in ASME B31G or the associated AGA report is subject to the limitations specified in the procedures. For example, the procedures are not appropriate for determining the ability of pipe to withstand stresses other than stress from internal pressure. Thus, if corroded pipe is under significant secondary stress (e.g., bending stress), an additional method must be used to determine the pipe's remaining strength.

The NAPSR report recommended amending § 192.483 to require the use of appropriate guides, such as those published by ASME and the Gas Piping Technology Committee, whenever the remaining strength of corroded pipelines must be determined. The majority of commenters who addressed this NAPSR recommendation opposed mandatory use of the guides. They said operators should retain the flexibility to decide when calculations under the guides are necessary. Even those commenters who supported the recommendation thought the rule should permit the use of other valid methods.

After considering the comments on proposed § 192.485(c) and the NAPSR recommendation, we believe the NAPSR recommendation would be unduly restrictive. Operators are now free to use any valid method to determine the remaining strength of corroded pipe, and we see no compelling reason to restrain this flexibility. The NPRM simply proposed to reference guidance documents that are generally available for operators to use at their discretion. Moreover, the proposal was written in a permissive sense to assist, but not restrict, operator decision-making. So we have amended the regulation essentially as proposed, but referenced both ASME B31G and the AGA report, with RSTRENG, to expand the information provided.

Section 192.491, Corrosion Control Records

Under § 192.491(a), operators must maintain records or maps showing the location of cathodically protected piping, cathodic protection facilities, other than unrecorded anodes installed before August 1, 1971, and neighboring structures bonded to the cathodic protection system. RSPA proposed to amend this requirement to relieve operators of the burden of making precise field measurements and preparing and maintaining records or maps showing the specific location of millions of individual anodes.

The TPSSC members voted unanimously for the proposal.

Comments on proposed § 192.491(a) were received from six pipeline operators, two pipeline-related associations, and one state agency. Eight commenters expressed their full or partial support with one commenter opposed. RSPA has accepted the recommendation of two operators that in the second sentence of proposed paragraph (a), the phrase ''Records and maps * * *'' should, for consistency with the rest of this section, be changed to ''Records or maps * * *.''

Section 192.491(b)(2) requires that operators retain records of corrosion control tests, surveys, and inspections for ''as long as the pipeline remains in service.'' RSPA proposed to reduce this retention period to at least 5 years for many records, because 5 years was thought to be adequate for compliance investigations and analysis of possible corrosion problems.

The proposal did not, however, extend to records under §§ 192.465 (a) and (e) and 192.475(b). These records relate to tests and inspections to determine the adequacy of, or need for, external and internal protection on existing lines. RSPA felt strongly that these records should continue to be kept for the service life of the pipeline, because they provide a valuable database for use in assessing corrosion problems.

The TPSSC unanimously supported the proposal.

Three pipeline-related associations, 10 operators, and one state agency commented on the proposal. Four of these commenters agreed with the proposal as written; the rest qualified their support by recommending changes.

Five commenters, including two pipeline-related associations and a state agency, were not persuaded of the importance of keeping records of corrosion monitoring under § 192.465 for the life of the pipe. Most of these commenters declared that 5 years would be adequate, but did not explain why a longer period is excessive. Lacking any convincing documentation to the contrary, RSPA believes the current rule should stay in effect. In our experience, a history of corrosion monitoring sheds light on the possible causes of a pipeline's condition. Such history has proven to be a valuable resource in deciding the extent and kind of remedial action needed when corrosion problems emerge on a pipeline.

Regarding the proposed 5-year retention time for records other than those required by §§ 192.465 (a) and (e) and 192.475(b), two commenters said the minimum time should be 3 years to coincide with the longest interval between inspections. Two others suggested that instead of a set time, we adopt a performance standard for record retention, basing it on the time needed to observe trends, inquire into compliance, or collect superseding data. All these comments provide a reasonable basis for record retention. However, our main concern is that operators keep records for a period that is compatible with the occurrence of routine compliance investigations. Therefore, for simplicity and uniformity, we have decided to adopt the proposed 5-year minimum retention time.

The state agency that commented objected to the 5-year proposal on grounds that it would sacrifice information about why external or atmospheric corrosion control was not installed on pipelines under §§ 192.455, 192.457, and 192.479. RSPA believes the loss of this information after 5 years would not be significant, because the pipelines involved are covered by requirements for periodic inspections or tests for corrosion under §§ 192.465 and 192.481.

Section 192.553, General Requirements

(See previous discussion under § 192.14).

Section 192.607, Determination of Class Location and Maximum Allowable Operating Pressure

Because § 192.607 has no continuing effect and the deadlines for compliance have expired, RSPA proposed to remove § 192.607 from part 192.

Fourteen TPSSC members voted for the proposal and one member abstained.

Five operators, one pipeline-related association, and one state agency commented on the proposed removal of § 192.607. Four operators and the association favored the idea. One operator and the state agency disagreed with removal, believing the rule is needed to tie a pipeline's maximum allowable operating pressure (MAOP) to its class location. Similarly, the NAPSR report recommended that we only remove the past compliance deadlines from § 192.607, leaving the rest of the rule in place to regulate the relation of class location to stress level on high-stress pipelines.

Section 192.607 was a transitional requirement. Its purpose was to establish plans under which operators initially determined class locations and confirmed or revised the MAOPs of their high-stress pipelines commensurate with their class locations. Section 192.607 provides that the plans had to be executed in accordance with § 192.611. This latter section together with § 192.609 are sufficient to require that operators have up-to-date class location determinations for high-stress pipelines, and maintain the MAOPs of those lines commensurate with their class locations.

Accordingly, § 192.607 is removed from part 192.

Section 192.611, Change in Class Location

Section 192.611 requires confirmation or revision of a pipeline's MAOP within 18 months after a change in class location. RSPA proposed to reorganize § 192.611 to clarify the requirement that the MAOP resulting from confirmation or revision may not exceed the pipeline's previous MAOP. This requirement is currently set forth in § 192.611(a)(3)(ii), suggesting that it applies only to confirmations or revisions under paragraph (a)(3), which is not the intent.

Fourteen TPSSC members voted for the proposal and one member abstained.

Five operators and one pipeline-related association commented on the proposal; each agreed with the proposal. Section 192.611 is, therefore, adopted as proposed in the NPRM.

Section 192.614, Damage Prevention Program

To decrease excavation damage to pipelines, § 192.614(b)(2) requires operators to notify excavators and the public about the need to locate buried pipelines before excavating. The NPRM proposed to amend the rule to clarify that in contrast to the actual notification required for excavators, only general notification is required for the public. General notice can be given through newspapers, radio, television, or other means of mass communication, as appropriate for the public in the vicinity of the pipeline.

Fourteen TPSSC members voted for the proposal and one member abstained.

Six pipeline operators and two pipeline-related organizations commented. Seven commenters gave their full or qualified approval and one commenter opposed the proposal. The qualified and negative comments were that the rule should inform operators of the acceptable means of notification. We do not feel it is necessary for the rule to do so, however, because the available means of giving general public notice are well known. The amendment to paragraph (b)(2) is adopted as proposed.

Section 192.619, Maximum Allowable Operating Pressure: Steel or Plastic Pipelines

Section 192.619(a) prescribes six pressure limits for use in determining the MAOP of steel and plastic pipelines, the lowest of which establishes the MAOP. Paragraph (a)(4) limits the MAOP of furnace butt welded pipe to 60 percent of the mill test pressure. Paragraph (a)(5) limits the MAOP of other steel pipe to 85 percent of the highest test pressure to which the pipe has been subjected, whether by mill test or by the post installation test.

RSPA proposed to repeal paragraphs (a)(4) and (a)(5), primarily because mill tests are not an adequate MAOP consideration. However, to assure consideration of longitudinal joint efficiency, RSPA also proposed, in paragraph (a)(2)(iii), that the class location pressure limit under existing paragraph (a)(2)(ii) be reduced for furnace butt welded pipe and lap welded pipe.

Eleven TPSSC members voted for the proposal, one member supported it with a recommended change, two members opposed it, and one abstained. A member recommended that RSPA not adopt proposed paragraph (a)(2)(iii) because design pressure (under paragraph (a)(1)) adequately covers longitudinal joint concerns.

RSPA concurs with this view as explained below in response to public comment.

Thirteen operators, four pipeline-related associations, and one state agency commented on the proposed amendment. Two operators, one pipeline-related association, and one state agency commented that proposed paragraph (a)(2)(iii) could require operators to reduce the operating pressure of some pipelines or test them to higher pressures than they previously were tested, possibly damaging the pipelines. In addition, some commenters stated that proposed paragraph (a)(2)(iii) would duplicate use of longitudinal joint factors.

Upon further consideration of our joint efficiency concern, RSPA concurs with these comments. Further, RSPA has no data showing that pipelines covered by proposed paragraph (a)(2)(iii) pose a risk that warrants pressure reduction or retesting. Therefore, although the final rule repeals paragraphs (a)(4) and (a)(5) as proposed, proposed paragraph (a)(2)(iii) is not adopted.

Section 192.625, Odorization of Gas

Section 192.619(f) requires operators to conduct periodic samplings of gas to assure the proper concentration of odorant. Based on a suggestion by the Oregon Public Utility Commission, the NPRM proposed to allow operators of master meter systems to comply with this sampling requirement by (1) receiving written verification from their gas supplier that odorant meets the required concentration, and (2) conducting periodic sniff tests at system extremities to confirm that the gas contains odorant.

Thirteen TPSSC members voted for the proposal, one against, and one member abstained.

Comments were received from eight pipeline operators, two pipeline-related associations, a mobile home association, and a consultant. One commenter favored the proposal and 11 commenters opposed it. Commenters opposing the proposal argued that (1) gas from a transmission line may be unodorized; (2) gas suppliers may be unwilling to provide written verification of odorization levels because of potential legal liability and the increased burden of providing the written verifications; (3) the frequencies of sniff tests and written verifications are unclear; and (4) the proposal would relax odorant monitoring requirements on gas systems which, in general, have a relatively high leakage rate.

The purpose of the proposal was to ease the sampling requirement for operators of master meter systems, who largely do not have the training or resources to adequately carry out the requirement. The alternative of getting written verifications and conducting sniff tests should be much less burdensome than purchasing, maintaining, and using an odorometer or contracting for odorant testing.

We do not feel this potential advantage is outweighed by any of the negative considerations the commenters raised. First of all, most master meter system operators purchase odorized gas from local distribution companies. Although some operators may receive unodorized gas from transmission lines and have to odorize the gas themselves, this situation does not warrant rejecting the proposed alternative. Those operators who receive unodorized gas simply would not be able to take advantage of the alternative. Similarly, operators could not take advantage of the alternative if their gas suppliers are unwilling to provide requested verifications of odorant level. But again this difficulty is no reason to deny the alternative to other operators. Regarding the frequency of verifications and sniff tests, the proposal called for an initial written verification from the gas supplier and periodic sniff tests thereafter. As with periodic sampling, the frequency of sniff tests would depend on the performance history of odorization in the system: the longer the period of satisfactory odorization, the longer the period between tests to assure proper odorant levels. Testing details would be specified in the operator’s operations and maintenance manual under § 192.605 and reviewed for adequacy by government inspectors. Finally, the charge that master meter systems have a high leakage rate was unsupported. In a 1984 report, ‘‘Exercise of Jurisdiction Over Master Meter Gas Operators,’’ RSPA concluded that master meter systems probably have a small leakage rate in comparison to the leakage rate of utility distribution systems. And more recent safety data continue to substantiate that conclusion. Therefore, after weighing the comments and favorable TPSSC vote, we have decided to amend § 192.625(f) as proposed.

Section 192.705, Transmission Lines: Patrolling

Operators of transmission lines must patrol their rights-of-way for indications of certain adverse conditions. Because of repeated questions about whether patrols may be done from the air, RSPA proposed to change § 192.705 to include aerial patrols as an optional method of compliance.

Fourteen TPSSC members voted for the proposal and one abstained.

Six operators and one pipeline-related association commented on the proposal. All but two of these commenters agreed with the proposal. One commenter that disagreed said a list of methods of compliance might be considered exclusive, thus disallowing other appropriate methods. The other commenter that disagreed thought the rule change unnecessary.

RSPA believes the phrase ‘‘or other appropriate means of traversing the right-of-way’’ in the proposed and final rule eliminates any chance the list of compliance methods might be considered exclusive. Also, the need for the rule change is based on RSPA’s experience in explaining the meaning of ‘‘patrol’’ under § 192.705. The change to § 192.705 is, therefore, adopted as proposed.

Section 192.709, Transmission Lines: Record Keeping

Section 192.709 requires operators to keep various records about transmission lines for as long as the line remains in service. RSPA proposed a shorter retention span that would not affect the usefulness of records in determining an operator’s level of compliance effort or in constructing the history of an accident or safety problem. RSPA proposed a minimum 5-year retention period for records of patrols, surveys, inspections, and tests, and a 1-year retention period for records of repairs on facilities other than pipe. We also proposed to clarify the information to be recorded.

Ten TPSSC members voted for the proposal, three members supported it with a recommended change, one member opposed it, and one abstained. The recommended changes were that 5 years should be changed to 3–5 years or to 10 years, and that leaks and linebreaks should also be recorded as the current § 192.709 provides. The ‘‘No’’ vote was predicated on an alleged need to keep records of repairs on valves, compressors, and other non-pipe components for 3–5 years.

As with final § 192.491(c), RSPA’s main concern about non-pipe records is that operators keep records for a minimum period that is compatible with the occurrence of routine compliance investigations. The suggested 3–5 years would not be long enough, and 10 years would be excessive. Therefore, we have adopted the proposed 5-year minimum period.

Repair records, as currently required, already provide information about leaks and linebreaks. Thus, requirements to keep the records of leaks and linebreaks were omitted from the proposed rule as unnecessary in view of this existing requirement.

As for the ‘‘No’’ vote, RSPA has adopted this minority TPSSC position as explained below in response to a comment by a state agency.

Eight operators, two pipeline-related associations, and one state agency commented on the proposed changes to § 192.709. Five of the operators supported the proposal without suggesting any modification.

Two other operators suggested 3 years as an alternative to the proposed 5-year minimum. But, as explained above, 3 years is insufficient for compliance monitoring purposes.

One operator thought the words ''for the useful life of the pipe'' under proposed § 192.709(a) could be misinterpreted. This commenter suggested that instead we adopt the words used in § 192.491(c): ''for as long as the pipeline remains in service.'' We agree that for consistency the two sections should use similar wording to describe similar record retention requirements. This comment was, therefore, adopted in the final rule.

One pipeline-related association recommended that § 192.709 be like 49 CFR 195.404(c), which applies to hazardous liquid pipelines. We did not adopt this comment because § 195.404(c) specifies a 2-year retention period for records of inspections and tests, a time we now find to be insufficient for purposes of compliance investigations. Otherwise the two sections are parallel. The other association reiterated its previous comment, which we opposed as discussed above, that record retention requirements should be performance based.

The state agency that commented objected to the proposed 1-year retention time for non-pipe repairs, saying it was inconsistent with the proposal to keep for at least 5 years records of inspections that may show the need for repair. This commenter reasoned that an inspector might not find any record showing the needed repair was made. RSPA agrees that the two requirements should be congruent. Therefore, the final rule requires that records of non-pipe repairs made as a result of a required patrol, survey, inspection, or test be kept for the same time required for records of such patrol, survey, inspection, or test.

Section 192.721, Distribution Systems: Patrolling

This section governs the frequency at which operators must patrol mains in distribution systems. The regulation is written in performance terms, except that mains located where anticipated movement or loading could cause leakage must be patrolled at intervals not exceeding 4½ months, but at least four times a year. RSPA proposed a more moderate patrol frequency of twice a year for such mains in Class 1 or 2 locations, in recognition of the lower risk in these less densely populated locations.

Twelve TPSSC members voted for the proposal, one against, one member supported it with a proposed change, and one abstained. The member against the proposal said that separating requirements on the basis of class locations is not always workable for distribution systems. Our response to this minority view is given below following similar comments by operators.

Four operators and two pipeline-related associations commented on the proposal. Three of the operators and one association supported the proposal, but the other operator and association thought class location should not be used as a basis for patrol frequency in distribution systems. One commenter suggested ''rural areas'' as an alternative to Class 1 and 2 locations.

RSPA agrees that the class location concept is not easy to apply in all distribution systems. Therefore, in the final rule, we have used the term ''business district'' to represent areas of higher risk and ''outside business districts'' to represent areas of lower risk. A similar classification method is already in place under § 192.723 for leakage surveys in distribution systems. The new patrol requirement matches that method. The term ''rural area'' was not adopted because it lacks precedent in part 192.

Rulemaking Notices and Analyses

Paperwork Reduction Act

This Final Rule revises information collection requirements in part 192 that are subject to review by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (Pub. L. 104–13). The following revised regulations reduce the existing paperwork burden by 28,326 hours:

- §§ 192.491 (a) and (b), ''Corrosion Control Records,'' reduces the paperwork burden by 22,486 hours by reducing the number of records, the precision of the measurements, and the amount of time the records must be kept.
- § 192.709, ''Transmission Lines; Record keeping,'' reduces the paperwork burden by 5,840 hours by reducing the amount of time the records must be kept.

Persons are not required to respond to a collection of information unless it displays a currently valid OMB control number. OMB has approved the revised information collection requirements of part 192 through May 31, 1999 (OMB No. 2137–0049).

Executive Order 12866 and DOT Regulatory Policies and Procedures

OMB considers this final rule to be a significant regulatory action under section 3(f) of Executive Order 12866. Therefore, OMB has reviewed the final rule. Also, DOT considers the final rule to be significant under its regulatory policies and procedures (44 FR 11034, February 26, 1979).

A final regulatory evaluation has been prepared and is available in the Docket. RSPA estimates the changes to existing rules will result in savings of $33,000,000 a year, without associated costs and with no adverse effect on safety. As discussed above, these savings come from the use of new technology, greater flexibility in constructing, maintaining, and operating pipelines, improved clarity, and the elimination of burdensome requirements.

Regulatory Flexibility Act.

RSPA criteria for small companies or entities are those with less than $1,000,000 in revenues and are independently owned and operated. Few of the companies subject to this rulemaking meet these criteria. Accordingly, based on the facts available concerning the impact of this final rule, I certify under Section 605 of the Regulatory Flexibility Act that this final rule will not have a significant economic impact on a substantial number of small entities.

E. O. 12612

The final rule would not have substantial direct effects on states, on the relationship between the Federal Government and the states, or on the distribution of power and responsibilities among the various levels of Government. Therefore, in accordance with Executive Order 12612 (52 FR 41685; October 30,1987), RSPA has determined that the final rule does not have sufficient federalism implications to warrant preparation of a Federalism Assessment.

List of Subjects in 49 CFR Part 192

Incorporation by reference, Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, RSPA amends 49 CFR part 192 as follows:

PART 192—[AMENDED]

1. The authority citation for part 192 continues to read as follows:

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

2. In § 192.1, paragraph (b)(1) is revised and paragraph (b)(4) is added to read as follows:

§ 192.1 Scope of part.

* * * * *

(b) This part does not apply to:

(1) Offshore pipelines upstream from the outlet flange of each facility where hydrocarbons are produced or where

produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

* * * * *

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

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

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

3. In § 192.3, a definition of ''Petroleum gas'' is added and the definition of ''Transmission line'' is revised to read as follows:

§ 192.3 Definitions.

* * * * *

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

* * * * *

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

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

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

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

* * * * *

4. Section 192.5 is revised to read as follows:

§ 192.5 Class locations.

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

(1) A ''class location unit'' is an onshore area that extends 220 yards on either side of the centerline of any continuous 1- mile length of pipeline.

(2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:

(1) A Class 1 location is:

(i) An offshore area; or

(ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

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

(3) A Class 3 location is:

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

(ii) An area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

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

(c) The length of Class locations 2, 3, and 4 may be adjusted as follows:

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

(2) When all buildings intended for human occupancy within a Class 2 or 3 location are in a single cluster, the class location ends 220 yards from the nearest building in the cluster.

5. Section 192.7(a) is revised to read as follows:

§ 192.7 Incorporation by reference.

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

* * * * *

6. Section 192.11 is revised to read as follows:

§ 192.11 Petroleum gas systems.

(a) Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this part and ANSI/NFPA 58 and 59.

(b) Each pipeline system subject to this part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this part and of ANSI/NFPA 58 and 59.

(c) In the event of a conflict between this part and ANSI/NFPA 58 and 59, ANSI/NFPA 58 and 59 prevail.

7. Section 192.107(b)(1)(ii) is revised to read as follows:

§ 192.107 Yield strength (S) for steel pipe.

* * * * *

(b) * * *

(1) * * *

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

* * * * *

8. Section 192.121 is revised to read as follows:

§ 192.121 Design of plastic pipe.

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

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

$$P = \frac{2S}{(SDR-1)}0.32$$

Where:

P=Design pressure, gauge, kPa (psig).

S=For thermoplastic pipe, the long-term hydrostatic strength determined in accordance with the listed specification at a temperature equal to 23°C (73°F), 38°C (100°F), 49°C (120°F), or 60°C (140°F); for reinforced thermosetting plastic pipe, 75,842 kPa (11,000 psi).

t=Specified wall thickness, mm (in).

D=Specified outside diameter, mm (in).

SDR=Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.

9. Section 192.123(b) is revised to read as follows:

§ 192.123 Design limitations for plastic pipe.

* * * * *

(b) * * *

(1) Below −29°C (−20°F), or −40°C (−40°F) if all pipe and pipeline components whose operating temperature will be below −29°C (−20°F) have a temperature rating by the manufacturer consistent with that operating temperature; or

(2) Above the following applicable temperatures:

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

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

* * * * *

10. The introductory text of § 192.179(a) is revised to read as follows:

§ 192.179 Transmission line valves.

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

* * * * *

11. Section 192.203(b)(2) is revised to read as follows:

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

* * * * *

(b) * * *

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

* * * * *

12. Section 192.227(b) is revised to read as follows:

§ 192.227 Qualification of welders.

* * * * *

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

13. In § 192.229, paragraph (c) is revised and paragraph (d) is added to read as follows:

§ 192.229 Limitations on welders.

* * * * *

(c) A welder qualified under § 192.227(a)—

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

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

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

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

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

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

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

14. Section 192.241(c) is revised to read as follows:

§ 192.241 Inspection and test of welds.

* * * * *

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 6 of API Standard 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if the Appendix to API Standard 1104 applies to the weld, the acceptability of the weld may be further determined under that Appendix.

15. Section 192.243(d)(4) is revised to read as follows:

§ 192.243 Nondestructive testing.

* * * * *

(d) * * *

(4) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

* * * * *

16. In § 192.281, paragraph (c)(3) is redesignated as paragraph (c)(4) and paragraph (c)(3) is added to read as follows:

§ 192.281 Plastic pipe.

* * * * *

(c) * * *

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

* * * * *

17. In § 192.283, the word ''or'' is removed from the end of paragraph (a)(1)(i), paragraph (a)(1)(ii) is revised, and paragraph (a)(1)(iii) is added to read as follows:

§ 192.283 Plastic pipe; qualifying joining procedures.

(a) * * *

(1) * * *

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

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

* * * * *

18. Section 192.317(a) is revised to read as follows:

§ 192.317 Protection from hazards.

(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

* * * * *

19. Section 192.319(c) is revised to read as follows:

§ 192.319 Installation of pipe in a ditch.

* * * * *

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

20. In § 192.321, paragraph (a) is revised and paragraph (g) is added to read as follows:

§ 192.321 Installation of plastic pipe.

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

* * * * *

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

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

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

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

21. In § 192.327, the introductory text of paragraph (a) is revised, paragraph (e) is revised, and paragraphs (f) and (g) are added to read as follows:

§ 192.327 Cover.

* * * * *

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

* * * * *

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

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

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

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

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

22. Section 192.375(a) is revised to read as follows:

§ 192.375 Service lines: Plastic.

(a) Each plastic service line outside a building must be installed below ground level, except that—

(1) It may be installed in accordance with § 192.321(g); and

(2) It may terminate above ground level and outside the building, if—

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

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

* * * * *

23. In § 192.455, paragraphs (a)(2) and (f)(1) are revised to read as follows:

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

(a) * * *

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

* * * * *

(f) * * *

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

* * * * *

24. Section 192.475(c) is revised to read as follows:

§ 192.475 Internal corrosion control: General.

* * * * *

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

25. Section 192.485(c) is added to read as follows:

§ 192.485 Remedial measures: Transmission lines.

* * * * *

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3–805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

26. Section 192.491 is revised to read as follows:

§ 192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

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

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

27. Section 192.553(d) is revised to read as follows:

§ 192.553 General requirements.

* * * * *

(d) *Limitation on increase in maximum allowable operating pressure.* Except as provided in § 192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under this part for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, the MAOP may be increased as provided in § 192.619(a)(1).

§ 192.607 [Removed and reserved]

28. Section 192.607 is removed and reserved.

§ 192.611 [Amended]

29. In § 192.611, paragraphs (b) and (c) are redesignated as (c) and (d), respectively; paragraph (a)(3)(ii) is redesignated as paragraph (b), and paragraph (a)(3)(iii) is redesignated as paragraph (a)(3)(ii).

30. In § 192.614, the introductory text of paragraph (b)(2) is revised to read as follows:

§ 192.614 Damage prevention program.

* * * * *

(b) * * *

(2) Provide for general 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:

* * * * *

31. In § 192.619, paragraph (a)(1) is revised to read as follows, paragraphs (a)(4) and (a)(5) are removed, paragraph (a)(6) is redesignated as paragraph (a)(4), and paragraph (b) is amended by removing ''(a)(6)'' and adding ''(a)(4)'' in its place:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) * * *

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under § 192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME B31.8, reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 324 mm (12¾ in) or less in outside diameter and is not tested to yield under this paragraph, 1379 kPa (200 psig).

* * * * *

32. Section 192.625 (f) is revised to read as follows:

§ 192.625 Odorization of gas.

* * * * *

(f) Each operator shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section. Operators of master meter systems may comply with this requirement by—

(1) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

(2) Conducting periodic ''sniff'' tests at the extremities of the system to confirm that the gas contains odorant.

33. Section 192.705(c) is added to read as follows:

§ 192.705 Transmission lines: Patrolling.

* * * * *

(c) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

34. Section 192.709 is revised to read as follows:

§ 192.709 Transmission lines: Record keeping.

Each operator shall maintain the following records for transmission lines for the periods specified:

(a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.

(b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section.

(c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

35. Section 192.721(b) is revised to read as follows:

§ 192.721 Distribution systems: Patrolling.

* * * * *

(b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—

(1) In business districts, at intervals not exceeding 4½ months, but at least four times each calendar year; and

(2) Outside business districts, at intervals not exceeding 7½ months, but at least twice each calendar year.

36. In Appendix A, section I. is amended by redesignating subsections A. through F. as subsections B. through G., respectively, and by adding a new subsection A.; and section II. is amended by redesignating subsections A. through E. as subsections B. through F., respectively, by adding a new subsection A. and a new subsection 12. to newly designated C., by redesignating newly designated subsections D.3. through D.5. as subsections D.5. through D.7., respectively, and by adding new subsections D.3. and D.4. as follows:

Appendix A—Incorporated by Reference

I. * * *

A. American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.

* * * * *

II. * * *

A. American Gas Association (AGA):

1. AGA Pipeline Research Committee, Project PR–3–805, ''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 22, 1989).

* * * * *

C. * * *

12. ASTM Designation: F1055 ''Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing'' (F1055–95).

D. * * *

3. ASME/ANSI B31G ''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991).

4. ASME/ANSI B31.8 ''Gas Transmission and Distribution Piping Systems'' (1995).

* * * * *

Issued in Washington, DC, on May 28, 1996.

D.K. Sharma,

Administrator.

[FR Doc. 96–13787 Filed 6–5–96; 8:45 am]

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 663

[Docket No. 960304057–6151–02; I.D. 020596A]

RIN 0648–AH84

Pacific Coast Groundfish Fishery; Framework for Treaty Tribe Harvest of Pacific Groundfish and 1996 Makah Whiting Allocation

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Final rule.

SUMMARY: NMFS is establishing a framework to implement the Washington coastal treaty Indian tribes' rights to harvest Pacific groundfish. NMFS also announces the allocation of 15,000 metric tons (mt) of Pacific whiting to the Makah Indian Tribe (Makah) for 1996 only, under the provisions of the regulatory framework.

EFFECTIVE DATE: May 31, 1996.

ADDRESSES: Copies of the Environmental Assessment/Regulatory Impact Review/Initial Regulatory Flexibility Analysis (EA/RIR/IRFA) may be obtained from the Director, Northwest Region, NMFS, 7600 Sand Point Way NE., BIN C15700, Seattle, WA 98115.

FOR FURTHER INFORMATION CONTACT: William L. Robinson at 206–526–6140.

SUPPLEMENTARY INFORMATION: NMFS is issuing this rule under the authority of the Pacific Coast Groundfish Fishery Management Plan (FMP) and the Magnuson Fishery Conservation and Management Act (Magnuson Act). It amends the FMP's implementing regulations to establish a clear procedure to accommodate the Washington coastal treaty Indian tribes' rights to harvest Pacific groundfish. At the same time, NMFS is modifying the groundfish regulations to consolidate regulations on treaty Indian fishing into one section and to provide for the treaty trawl harvest of midwater groundfish species. Under the provisions of this rule, NMFS announces the allocation of 15,000 mt of Pacific whiting to the Makah for 1996. For purposes of this rule, Washington coastal treaty Indian tribes means the Hoh, Makah, and Quileute Indian Tribes and the Quinault Indian Nation.

This rule is implemented under authority of section 305(d) of the Magnuson Act, which gives NMFS,