DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket No. PHMSA–1998–4868; Amdt. 192–102]

RIN 2137–AB15

Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Final rule.

SUMMARY: This action adopts a consensus standard to distinguish onshore gathering lines from other gas pipelines and production operations. In addition, it establishes safety rules for certain onshore gathering lines in rural areas and revises current rules for certain onshore gathering lines in nonrural areas. Operators will use a new risk-based approach to determine which onshore gathering lines are subject to PHMSA's gas pipeline safety rules and which of these rules the lines must meet. PHMSA intends this action to reduce disagreements over classifications of onshore gathering lines, increase public confidence in the safety of onshore gathering lines, and provide safety rules consistent with the risks of onshore gathering lines.

DATES: This final rule takes effect April 14, 2006. The Director of the Federal Register approves the incorporation by reference of API RP 80 in this rule as of April 14, 2006.

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SUPPLEMENTARY INFORMATION:

I. Background

A. Current Regulation of Onshore Gathering Lines; Definition Problem

Gas gathering lines are pipelines used to collect natural gas from production facilities and transport it to transmission or distribution lines, which then transports it to the consumer. PHMSA's pipeline safety rules in 49 CFR part 192 apply to the transportation of natural gas and other gas by pipeline. However, onshore gathering lines in rural areas (areas outside cities, towns, villages, or designated residential or commercial areas) are subject only to § 192.612, which prescribes inspection and burial requirements for lines within Gulf of Mexico inlets (§§ 192.1(b)(4) and (b)(5)). (**Note:** Lines in these inlets are not covered by this final rule.)

Under § 192.9, gathering lines in nonrural areas must meet the same safety standards for design, construction, testing, operation, and maintenance as gas transmission lines, except the requirements of § 192.150 on passage of an internal inspection device (also known as smart pigs) and subpart O on integrity management. In addition, PHMSA's drug and alcohol testing regulations in 49 CFR part 199 apply to nonrural gas gathering lines.

Section 192.3 currently defines the terms ''gathering line,'' ''transmission line,'' and ''distribution line'':

> ''Gathering line'' means a pipeline that transports gas from a current production facility to a transmission line or main. ''Transmission line'' means a pipeline, other than a gathering line, that transports gas from a gathering line or storage facility to a gas distribution center or storage facility; operates at a hoop stress of 20 percent or more of a Specified Minimum Yield Strength (SMYS), or transports gas within a storage field. ''Distribution line'' means a pipeline other than a gathering or transmission line.

Because these definitions are circular and part 192 does not define ''production facility,'' operators and government inspectors have had difficulty distinguishing regulated gathering lines from unregulated production facilities and unregulated gathering lines from regulated transmission and distribution lines. Also, the complexity of many gathering systems has increased the difficulty of distinguishing gathering lines.

B. Past Attempts To Resolve the Definition Problem and Determine the Need To Regulate Rural Gathering Lines

In 1974, DOT tried to correct the problem of distinguishing gathering lines by proposing to revise the gathering line definition (39 FR 34569; Sept. 26, 1974). However, the proposal was later withdrawn because comments indicated many terms and phrases were unclear (43 FR 42773; Sept. 21, 1978). Afterward, the problem lingered until 1986, when the National Association of Pipeline Safety Representatives (NAPSR), a nonprofit association of State pipeline safety officials, surveyed its members and reported numerous and continuing disagreements with operators over gathering lines. Driven by the NAPSR survey, in 1991 DOT again proposed to revise the gathering line definition (56 FR 48505; Sept. 25, 1991). However, the public response was generally unfavorable, so DOT delayed any further action until it collected and considered more information.

Part 192 does not regulate the safety of most rural gathering lines because, until 1992, the pipeline safety law (49 U.S.C. Chapter 601) restricted DOT's authority over onshore gathering lines to lines in nonrural locations.[1] In 1992, Congress gave DOT specific authority to define gas gathering lines for purposes of safety regulation, and to regulate a class of rural gathering lines called ''regulated gathering lines'' (49 U.S.C. 60101(a)(21) and 60101(b)). The new authority directed DOT to consider functional and operational characteristics in defining gathering lines. Further direction was to consider such factors as location, length of line, operating pressure, throughput, and gas composition in deciding which rural lines warrant regulation. This authority also expressly allows PHMSA to depart from the concepts of gathering under the Natural Gas Act (15 U.S.C. 717 *et seq.*)

In 1999, in furtherance of the still open 1991 gathering line proceeding and Congress' action on gathering lines, DOT opened a Web site for public discussion of the definition problem and the need to regulate rural gathering lines (Docket No. PHMSA–1998–4868; 64 FR 12147; Mar. 11, 1999). The comments mainly focused on the comprehensive work by the American Petroleum Institute (API), later published as API Recommended Practice 80, ''Guidelines for the Definition of Onshore Gas Gathering Lines'' (API RP 80). API RP 80 defines onshore gas gathering lines through a series of definitions, descriptions, and diagrams intended to represent the varied and complex nature of production and gathering in the U.S. Although industry commenters spoke favorably about the API RP 80 gathering line definition, NAPSR objected to the use of certain ''furthermost downstream'' endpoints to mark the beginning and end of gathering. NAPSR's concern was if the definition were included in part 192, operators would have an incentive to establish or move the endpoints further downstream to reduce the amount of regulated pipelines. While considering its next step, DOT published an Advisory Bulletin to remind operators it was still regulating gathering lines according to court precedents and its prior interpretations (67 FR 64447; October 18, 2002).

Then in 2003, DOT held public meetings in Austin, Texas (68 FR 62555; November 5, 2003) and Anchorage, Alaska (68 FR 67129; December 1, 2003)

[1] In 1990 Congress gave DOT limited authority over gathering lines in Gulf of Mexico inlets (*see* Pub. L. 101–599).

to attract more comments on the best way to define gas gathering lines and what, if any, safety rules may be needed for rural gathering lines. At the meetings, DOT gave the history of the gas gathering issue and proffered a ''sliding corridor'' concept as a possible basis for deciding which lines should be regulated. Under this concept, previously used in a pipeline safety enforcement case, operators would slide along their gathering lines an imaginary corridor with dimensions 1000 feet long and the width would be based on the stress level. Wherever the corridor contained five or more dwellings, the gathering line would be subject to safety rules, the intensity of which would increase with the stress level. Transcripts of both meetings are in the docket (PHMSA–1998–4868–120 and 122).

As a follow-up to these two meetings, DOT published a notice extending the time for comments and clarifying its intentions about defining and regulating gathering lines (69 FR 5305; February 4, 2004). DOT said definitions of production and gathering should not overlap State regulations on production and should be capable of consistent application by regulators and operators. Also, the notice explained the need for comments on an appropriate approach to identify rural lines warranting regulation. After the 2003 public meetings, DOT met several times with State agency officials, industry representatives, and others to obtain views on gathering line risks and the need for safety rules. Notes of these informal meetings are in Docket No. PHMSA–1998–4868.

C. Public Comments Resulting From the Public Meetings

Twenty-three comments were submitted as a result of the public meetings and clarification notice. Three industry commenters expressed satisfaction with the current part 192 gathering line definition and prior DOT interpretations. But most commenters, including a coalition of trade associations, urged adoption of API RP 80 as the basis for determining onshore gas gathering lines. These commenters believed it would result in few, if any, reclassifications of pipelines from production to gathering or gathering to transmission. However, NAPSR opposed the unqualified use of API RP 80 because of its use of the term ''furthermost downstream'' to identify the beginning and possible ends of gathering. NAPSR suggested several limitations to prevent manipulating the term ''furthermost downstream'' to change production to gathering or gathering to transmission.

On the need to regulate rural lines, some trade associations contended rural gathering lines generally pose a low risk to public safety, citing an incident survey the Gas Processors Association (GPA), a trade association representing gatherers and processors, conducted in December 2003. These trade associations and the U.S. Department of Energy (DOE) suggested that DOT should first identify and analyze the risks involved and then target regulations to specific problems. Cook Inlet Keeper, a nonprofit organization dedicated to protecting Alaska's Cook Inlet Watershed and North Slope Borough, the northernmost county of Alaska, advocated regulation of all unregulated lines threatening people and the environment. Cook Inlet Keeper also submitted data on releases from unregulated pipelines in Alaska.

GPA presented the survey at a meeting of PHMSA's gas pipeline safety advisory committee on February 5, 2004 (Docket No. PHMSA–1998–4470–120). The survey asked 40 operators of rural gas gathering lines about incidents impacting the public during a 5-year period (1999–2003). The survey showed 58 incidents occurred on 171,768 miles of pipeline, about 96 percent of GPA members' gathering lines. The incidents resulted in three injuries and one death as well as evacuations, minor property damage ($5,000–$25,000), and major property damage (over $25,000). Corrosion caused most of the incidents, followed by third-party excavation, which produced the most severe consequences (including the death and two of the injuries). No other cause occurred more than twice. In comparison to transmission incidents reported to DOT over the same period, transmission lines impacted the public from three to six times more often, even though the reporting threshold for property damage was 10 times as high as the survey's threshold. GPA attributed the lower impact of rural gathering lines to operators' safety practices and to operating conditions generally involving sparsely populated areas, low pressures, and small pipe sizes.

Concerning the approach to regulation, the coalition suggested an overall plan covering rural and nonrural lines under which the intensity of regulation would increase with risk determined by operating parameters and population density. Under the current plan, regulated nonrural gathering lines posing a lower risk would be subject to fewer safety rules than they are now. ONEOK, Inc., an operator of gas gathering lines, suggested a similar but more detailed tiered approach. Delta County, Colorado preferred the ''sliding corridor'' approach discussed at the public meetings. Two industry commenters favored a hands-off approach that would leave the regulation of rural gathering to State agencies already regulating oil and gas production.

Several trade associations were concerned about the impact of any new DOT regulations on rural gathering lines. DOE and the Independent Petroleum Association of America were particularly concerned that increased costs could cause producers to shut in marginally profitable wells. They pointed out that since marginal wells account for about 10 percent of U.S. gas production, additional costs could reduce gas supplies.

D. Alternatives To Resolve the Definition Problem

Considering the previous attempts in 1974 and again in 1991 to resolve the definition problem were controversial, we concluded a single definition wholly consistent with industry's complex practices probably could not be developed. So we looked closer at API RP 80. Its development by a wide range of experienced personnel, its attention to detail, and its backing by commenters led us to believe it could, if used appropriately, distinguish gathering lines under part 192 without the controversy attendant to the earlier proposals. In reaching this conclusion, we did not intend persons to use API RP 80 for non-safety purposes, such as to identify gathering under the Natural Gas Act. By its own terms, API RP 80 applies only in the context of pipeline safety: ''[T]he definitions presented herein are not designed to address issues—nor are they intended for application—in any regulatory context other than gas pipeline safety pursuant to the Federal Pipeline Safety Act'' (section 2.6.2.4 of API RP 80).

We considered the following ways API RP 80 could serve to determine onshore gas gathering under part 192:

1. Use API RP 80 as guidance to determine the beginning and end of onshore gathering under the present part 192 definition. The advantages of this alternative were some operators would likely support it and rulemaking would not be necessary. On the other hand, this alternative would probably not be sufficient to satisfy the congressional directive to define gas gathering and it would provide a shaky basis for regulating rural gathering lines. In addition, NAPSR's comments suggested many State pipeline safety

agencies would be unlikely to accept some API RP 80 provisions even as guidance.

2. Adopt API RP 80 as the basis for determining onshore gas gathering lines. This alternative had wide industry support, would likely minimize the difficulty of distinguishing gathering lines, and would likely result in few pipeline reclassifications. However, API RP 80's many supplemental definitions, descriptions, and diagrams, although helpful, could be difficult to apply uniformly. Also, as NAPSR contended, the ''furthermost downstream'' provisions of API RP 80 could result in manipulation of endpoints to avoid pipeline regulation. If that happened, State pipeline safety agencies could lose control over many miles of pipeline they now regulate, and public safety could be compromised.

3. Adopt API RP 80, but with limitations to remove opportunities for manipulation. The main advantage of this alternative was it would balance industry's desire to use API RP 80 with NAPSR's desire for definite endpoints. The disadvantage was limitations could make API RP 80 more difficult to apply. In addition, any limitation could renew industry's claims of line reclassifications. As discussed further in section II of this preamble, we chose this alternative for the proposed definition of ''onshore gathering line.''

E. Need for DOT Rules on the Safety of Onshore Rural Gathering Lines

PHMSA has authority under 49 U.S.C. 60102(a) to issue safety standards for gas pipeline transportation. In 1992, Congress granted DOT specific authority to define gas gathering for purposes of safety regulations. Congress also recognized that some rural gathering lines might present unacceptable risks and authorized DOT to regulate lines whose risk warranted regulation. In its report on H.R. 1489, a bill leading to the 1992 change in the law, the House Committee on Energy and Commerce said ''DOT should find out whether any gathering lines present a risk to people or the environment, and if so how large a risk and what measures should be taken to mitigate the risk.'' (H.R. Report No. 102–247, Part 1, 102nd Cong., 1st Sess. 23 (1991)).

As discussed above, because DOT lacked information about whether the risks of rural lines warranted regulation, it held a Web discussion and then two public meetings to get input from the public on the need to regulate these lines. GPA submitted the most detailed information based on a survey of its members. Although the survey results showed rural gathering lines presented a lower risk to the public than transmission lines, the impacts to the public and property during the survey period were not insignificant. Many people living or working near rural lines suffered adverse consequences. Also, the potential for future harm was apparent, because the survey confirmed the leading threats to rural gathering lines: corrosion and excavation damage, matched the leading threats to regulated gas pipelines.

Not all rural gathering lines present as low a risk as the lines in GPA's survey. Some rural lines are near pockets of housing or operate at high pressures threatening housing further away. In fact, high-pressure gathering lines in populated areas can present the same risk as regulated transmission lines.

In consideration of the known and foreseeable risks presented by rural gathering lines, we decided it was no longer appropriate to maintain the almost total exemption of rural lines from part 192. But in changing the present exemption, we also decided to focus on lines posing significant risk, or lines located where a release of gas could have serious consequences.

F. Approach To Regulating Onshore Gathering Lines

We believe the potential for harm of some onshore gathering lines is too low to warrant DOT regulation. These lines generally have small diameters and operate at low pressures in remote or secluded areas.

For other lines, we agree with commenters that the level of regulation should increase as risk increases by operating pressure and proximity to people. Under this approach, the highest risk lines would have the most regulation. This approach is consistent with the statutory directive on determining which rural gathering lines warrant regulation.

In deciding what safety rules to apply according to risk, we favored the tiered models two commenters suggested. Tiers are a reasonable way to pair safety regulations with lines posing different levels of risk. However, considering the need for practicality in both compliance and enforcement, we created a model with only two tiers. This approach is discussed in more detail in section II of this preamble.

Currently, part 192 regulates nonrural gathering lines and transmission lines similarly, except § 192.150 pig passage and subpart O apply only to transmission lines. Nevertheless, PHMSA's incident data indicate gathering and transmission lines do not pose the same overall level of risk to the public. This data shows that transmission line incidents have had a greater impact on the public than gathering line incidents. We therefore believe a significant factor in many nonrural gathering line segments is that they operate at low pressures away from highly populated areas. So safety rules intended for all transmission lines are probably not appropriate for all gathering lines.

A related problem with the current part 192 approach to regulation of nonrural lines involves line segments inside sparsely populated areas of cities or towns. Often a city or town will extend its boundaries to incorporate these rural-like areas. For instance, a low-pressure gathering line in such areas may be distant from any populated site but because it lies within city or town boundaries it becomes subject to part 192 and must meet transmission line rules.

We believe a risk-based approach is the most suitable for applying part 192 rules to onshore gathering lines whether the lines are in rural or nonrural areas. Regulation of an onshore gathering line should not depend on subdivision or local government boundaries as it does now, but on the risk the line poses to the public based on its pressure and proximity to people. For example, the proximity of a line to dwellings is a much more precise measure of risk than the rural-nonrural approach currently in use. For nonrural lines, this change to a risk-based approach would maintain the current level of regulation where justified by risk. At the same time, it would lighten the present regulatory burden on less risky lines.

II. Proposed Rules

To get public comments on its latest approach to defining and regulating the safety of onshore gas gathering lines, on October 3, 2005, PHMSA published a supplementary notice of proposed rulemaking (SNPRM) (70 FR 57536). The SNPRM was a continuation of the rulemaking proceeding started by the 1991 notice of proposed rulemaking (NPRM).

The SNPRM sought comments on proposed new definitions of the terms ''onshore gathering line'' and ''regulated onshore gathering line.'' These definitions would provide the basis for determining which gas pipelines would be subject to part 192 rules for regulated onshore gathering lines. Any onshore gathering line not covered by the proposed definition of ''regulated onshore gathering line'' would not be subject to part 192. The SNPRM also sought comments on proposed risk-based safety rules for regulated onshore gathering lines. A description of the proposed definitions and safety rules follows.

A. Proposed Definition of ''Onshore Gathering Line''

We wanted to define ''onshore gathering line'' in a way that not only reasonably matched current classifications but also addressed NAPSR's concerns. So we proposed to allow operators to use API RP 80 to determine ''onshore gathering lines.'' But use of API RP 80 would be subject to the following five limitations on the beginning of gathering and the possible endpoints of gathering under section 2.2(a) of API RP 80:

1. Under section 2.2(a)(1), the beginning of an onshore gathering line is the furthermost downstream point in a production operation. We proposed to restrict this point to piping or equipment used solely in the process of extracting natural gas from the earth for the first time and preparing it for transportation or delivery. The purpose of the limitation was to ensure certain dual-use equipment, capable of use in either production or transportation, would be part of gathering when not used solely in the process of extracting and preparing gas for transportation.

2. Under section 2.2(a)(1)(A), the first possible endpoint is the inlet of the furthermost downstream natural gas processing plant, other than a natural gas processing plant located on a transmission line. We proposed this endpoint may not be a natural gas processing plant located further downstream than the first downstream natural gas processing plant unless the operator can demonstrate, based on sound engineering reasons, gathering should extend beyond the first plant. Past DOT interpretations and State agency enforcement actions have recognized the first downstream natural gas processing plant as the customary end of gathering. (See PHMSA's Web site for interpretations and enforcement actions: *http://www.phmsa.dot.gov/*.)

3. Under section 2.2(a)(1)(B), the second possible endpoint is the outlet of the furthermost downstream gathering line gas treatment facility. We proposed this endpoint would apply only if no other endpoint under sections 2.2(a)(1) (A), (C), (D) or (E) existed.

4. Under section 2.2(a)(1)(C), the third possible endpoint is the furthermost downstream point where gas produced in the same production field or separate production fields are commingled. This endpoint recognizes a gathering line may receive gas from several production fields. But because it does not restrict the distance between fields, gathering could potentially continue endlessly, causing reclassifications from transmission to gathering along the way. To set a reasonable limit, we proposed that separate production fields from which gas is commingled must be within 50 miles of each other. We specifically invited comments on whether a maximum distance is needed.

5. Under section 2.2(a)(1)(D), the fourth possible endpoint is the outlet of the furthermost downstream compressor station used to lower gathering line operating pressure to facilitate deliveries into the pipeline from production operations or to increase gathering line pressure for delivery to another pipeline. For consistency with our past interpretations and current enforcement policy, we proposed to limit this endpoint to the outlet of a compressor used to deliver gas to another pipeline.

We did not propose a limitation on the fifth possible endpoint under section 2.2(a)(1)(E). This endpoint is the connection to another pipeline downstream of the furthermost downstream endpoint under sections 2.2(a)(1)(A) through (D), or in the absence of such an endpoint, the furthermost downstream production operation. The endpoint applies to connecting lines described as ''incidental gathering'' under section 2.2.1.2.6 of API RP 80. An example of a connecting line is a pipeline that runs from the outlet of a natural gas processing plant to a transmission line. PHMSA considers ''incidental gathering'' to include only lines that directly connect a transmission line to one of the endpoints (A) through (D), as limited by this final rule. Lines that connect a transmission line to one of these endpoints by way of another facility are not considered ''incidental gathering.''

B. Proposed Definition of ''Regulated Onshore Gathering Line''

We proposed to amend § 192.3 to define ''regulated onshore gathering lines'' by either of two risk categories, Type A and Type B, based on operating stress and location. Type A would include lines whose maximum allowable operating pressure (MAOP) results in a hoop stress of 20 percent or more of SMYS, and non-metallic lines whose MAOP is more than 125 per square inch gauge (psig). The location would be Class 3 and 4 locations, as defined in § 192.5, and other areas the operator determines using potential impact circles with five or more dwellings or a sliding corridor 440 yards by 1000 feet with either 5 or more dwellings per 1000 feet or 25 or more dwellings per mile, whichever results in more regulated lines. Type A lines in a Class 1 or Class 2 location would also include additional lengths of line upstream and downstream to serve as a shield against potential harm to nearby dwellings.

Type B lines would include metallic lines whose MAOP produces a hoop stress of less than 20 percent of SMYS, and non-metallic lines whose MAOP is 125 psig or less. The location would be Class 3 and 4 locations and other areas determined by a sliding corridor 300 feet by 1000 feet with 5 or more dwellings per 1000 feet. Lines within a Class 1 or Class 2 location would include additional lengths of line as a shield against potential harm to nearby dwellings.

C. Proposed Safety Requirements

We proposed to revise § 192.9 to include safety requirements for all gathering lines subject to part 192. Paragraph (b) would simply restate the present part 192 requirements applicable to offshore gathering lines.

Under paragraph (c), Type A regulated onshore gathering lines would have to meet part 192 requirements applicable to transmission lines, except requirements concerning the passage of smart pigs (§ 192.150) and integrity management (subpart O). Because of the higher stress at which Type A lines operate and their ability to harm more of the public, we considered Type A lines to warrant safety requirements equivalent to transmission line requirements. Currently regulated gathering lines are subject to these requirements.

Paragraph (d) contains the proposed requirements for Type B regulated onshore gathering lines. These lines, although located near the public and housing, operate at a lower stress than Type A lines and pose a lower-risk. So for Type B lines, we proposed safety requirements focused just on the main threats to these lines—corrosion and excavation damage. First, new lines and existing lines replaced, relocated, or otherwise changed would have to be designed, installed, constructed, initially inspected, and initially tested according to part 192 requirements. Second, operators of Type B lines would have to control corrosion according to applicable subpart I requirements; carry out a damage prevention program under § 192.614; establish MAOP under § 192.619; install and maintain line markers under § 192.707 according to transmission line requirements; and establish a public education program as required by § 192.616.

To allow time for line identification and preparation for compliance, we proposed extended compliance deadlines in paragraph (e) for operation and maintenance requirements. Similarly, we proposed to amend § 192.13 to allow 1 year after the final rule takes effect before new, replaced, relocated, or otherwise changed lines would have to meet design and construction requirements. Also in paragraph (e), we proposed to allow operators 1 year to bring unregulated lines into compliance if they become regulated because of changes in population.

In addition, we proposed to ease the transition to regulated status of newly regulated lines and lines subsequently regulated due to population increases by revising the MAOP requirements of §§ 192.619(a)(3) and (c). The proposal would allow operation of a line at the highest actual operating pressure to which it was subjected during the 5 years before the final rule is published or the line becomes regulated.

As part of the corrosion control requirements, we proposed to apply those subpart I requirements specifically applicable to pipelines installed before August 1, 1971, to regulated onshore gathering lines in existence when the final rule takes effect and not previously subject to subpart I (lines in rural locations). Other subpart I requirements specifically applicable to pipelines installed after July 31, 1971, would not apply to these existing lines unless they substantially meet the requirements.

D. Related Proposals

We proposed to amend § 192.1(b)(4) to exclude from part 192 onshore gathering lines operating under vacuum, or at less than atmospheric pressure. We reasoned that regulation was not necessary because these lines pose little risk since they cannot release natural gas to the atmosphere. An additional amendment to this section clarifies the present rulemaking on onshore gathering lines does not affect gathering lines in inlets of the Gulf of Mexico.

III. Advisory Committee Recommendations

The Technical Pipeline Safety Standards Committee (TPSSC), a statutorily mandated advisory committee, advises PHMSA on proposed safety standards and other policies concerning gas pipelines. The committee has an authorized membership of 15 persons with membership evenly divided between government, industry, and the public. Each member is qualified to consider the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed pipeline safety standards.

The TPSSC considered the SNPRM at a teleconference on January 19, 2006. During the conference, we discussed the public comments summarized in section IV of this preamble and the draft Regulatory Evaluation of costs and benefits. After careful consideration, the TPSSC voted unanimously to find the SNPRM and supporting Regulatory Evaluation technically feasible, reasonable, practicable, and cost-effective, subject to resolution of the comments in the manner we discussed. A transcript of the teleconference is available in Docket No. PHMSA–98–4470.

IV. Disposition of Comments on Proposed Rules

We received written comments on the SNPRM from 19 sources: American Gas Association (AGA), Clark Resource Council and Powder River Basin Resource Council, Columbia Gas Transmission Corporation (Columbia), Cook Inlet Keeper, Dominion Delivery (Dominion), Duke Energy Field Services (Duke), Equitable Resources (Equitable), Independent Petroleum Association of America (IPAA), National Association of Pipeline Safety Representatives (NAPSR), National Fuel Gas Supply Corporation (NFGSC), Oil and Gas Industry Onshore Gas Gathering Regulation Coalition (Coalition), Oklahoma Corporation Commission (OCC), Oklahoma Independent Petroleum Association (OIPA), Pipeline Safety Trust (PST), Public Service Commission of West Virginia (PSCWV), Public Utilities Commission of Ohio, Robert A. Honig, Susan Franzheim, and West Texas Gas, Inc. (West).

In the SNPRM, we discussed the impact our proposed gathering line definition might have on economic decisions of the Federal Energy Regulatory Commission (FERC). Although we concluded the definition was unlikely to influence FERC's decisions, we suggested an alternative approach that would not define gathering lines, just which gathering lines would be regulated for safety. We specifically invited comments on the potential impact of the proposed definition on FERC decisions, on ways to avoid difficulties of the alternative approach, and on advantages and disadvantages of either approach. No one who submitted comments on the SNPRM addressed any of these issues either directly or indirectly. We continue to believe that the approach we adopt in this final rule will not have implications on FERC practice. This approach does not rely on the Natural Gas Act for determining if a pipeline is a gathering line.

Commenters generally favored the proposed definitions and tiered safety requirements subject to changes discussed in the outline below. However, West was against regulation of rural gathering lines, saying it was not needed because strong economic and liability-avoidance incentives encourage safe operations, and States can act if needed. West also said the Regulatory Evaluation was based on unsubstantiated assumptions, particularly with respect to the impact of lost reserves due to premature abandonment of stripper wells.

We disagree with West on the need for DOT regulation of rural gas gathering lines. Although operators have economic and legal incentives to operate these lines safely and States can take regulatory action, we think DOT regulation is still needed. As explained above in section I of this preamble, this need derives from the Congress' concern about the safety of higher-risk rural gathering, public comments favoring regulation where warranted by risk, and the incident data industry submitted showing rural gathering lines experience the same leading causes of accidents as lines PHMSA now regulates. Thus, the present exemption of rural gathering lines from nearly all safety rules in part 192 is no longer appropriate. We took West's comment on the draft Regulatory Evaluation into account in preparing a final evaluation.

A. Limitations on Using API RP 80 Definition of ''Gathering Line''

As explained in the SNPRM, we proposed to adopt API RP 80 as the basis for determining onshore gathering lines and which of these lines would be subject to part 192 (70 FR 57540). Under this proposal, to determine if a pipeline is an onshore gathering line, operators would use API RP 80 in its entirety, including the definition of ''gathering line'' in section 2.2, the definition of ''production operation'' in section 2.3,[2] the supplemental terms in section 2.4, and the Decision Trees, and Representative Applications.

However, we recognized the definition of ''gathering line'' in section 2.2 of API RP 80 is susceptible to manipulation because it uses the term ''furthermost downstream'' to identify

[2] As defined in section 2.3 of API RP 80, ''production operation'' means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) Extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply.

facilities marking the beginning and end of a gathering line. By installing certain dual-use equipment (equipment used in either production or pipeline transportation, such as separators or dehydrators) further downstream from normal production, operators could arguably extend production and reduce the amount of regulated gathering. Similarly, the ''furthermost downstream'' feature would allow operators to manipulate gathering endpoints marking the changeover to transmission, resulting in inconsistencies with prior DOT interpretations. So we proposed the following five limitations on use of the definition.

1. Limitation on Furthermost Point of Production

Under section 2.2(a)(1) of API RP 80, gathering begins at the furthermost downstream point in a ''production operation.'' We proposed the following limitation on this aspect of the definition:

> The beginning of a gathering line may not be further downstream than piping or equipment used solely in the process of extracting natural gas from the earth for the first time and preparing it for transportation or delivery.

The purpose was to classify dual-use equipment as transportation equipment if it is not used in the process of producing and preparing gas for transportation. In other words, once produced gas enters pipeline transportation, any dual-use equipment installed further downstream would be transportation equipment and not production equipment.

a. Comments

Coalition thought the limitation would expand gathering to include facilities, such as centralized separation, that API RP 80 describes as ''production operations.'' It offered the following alternative wording to preclude production manipulation:

> The beginning of a gathering line * * * shall not be artificially circumvented by:
>
> (1) The installation of one or more pieces of equipment at an extreme downstream location not normally associated with a production operation; or
>
> (2) Natural gas injection into, and subsequent withdrawal from, a gas storage cavern or field.

Similarly, IPAA found the proposal confusing and said it would impact potentially thousands of producers across the country. It urged us to adopt a clear production definition, and suggested the following:

> ''Production Operation'' means any piping and equipment that qualify as a production operation under section 2.3 of API RP–80, with the following limitations: (1) Facilities operated in connection with natural gas storage operations shall be excluded; and (2) separation and dehydration facilities located contrary to the prudent operating standards commonly applicable in the industry to the particular geographic location and solely for the purpose of avoiding regulation as a gathering line under Title 49 of the Code of Federal Regulations, part 192, shall be excluded.

OCC, OIPA, NAPSR, and PST found the proposed limitation ambiguous. They too recommended alternative solutions. OCC and OIPA asked us to clarify the reference to the API RP 80 definition of ''production operations.'' NAPSR and PST recommended adding the phrase ''for the first time'' at the end of the proposed limitation.

b. PHMSA Response

We think the text of the proposed rule (70 FR 47546) was the cause of the commenters' concerns. Nowhere does the proposed text say operators must use API RP 80 in its entirety to determine onshore gathering lines, even though in the SNPRM preamble we proposed such use subject to certain limitations on section 2.2. This omission created uncertainty about use of the API RP 80 definition of ''production operations.'' In addition, commenters may have thought the phrasing of the proposed limitation would narrow the meaning of ''production operations'' in API RP 80. However, we merely intended the limitation to clarify the classification of dual-use equipment positioned downstream from production operations.

To resolve this misunderstanding, the final rule does not add a definition of ''onshore gathering line'' to § 192.3 as proposed. Instead, we created a new § 192.8, titled ''How are onshore gathering lines and regulated onshore gathering lines determined?'' Paragraph (a) of this new section allows operators to determine onshore gathering lines according to API RP 80, subject to certain limitations. Thus, operators must use API RP 80 in its entirety to determine onshore gathering lines, not just section 2.2 as the proposed definition of ''onshore gathering line'' implied.

In addition, in final § 192.8(a)(1), we changed the proposed limitation on the furthermost point of production to focus on the classification of dual-use equipment. The limitation now provides the beginning of gathering may not extend beyond the furthermost downstream point in a production operation. This furthermost point does not include equipment capable of use in either production or transportation, such as separators or dehydrators, unless the equipment is involved in the processes of ''production and preparation for transportation or delivery of hydrocarbon gas'' within the meaning of ''production operation'' under section 2.3 of API RP 80. This change removes any inference that the limitation narrows the meaning of ''production operation'' under section 2.3 of API RP 80.

We did not adopt commenters' suggestions to exclude from production ''equipment at an extreme downstream location not normally associated with a production operation'' or ''facilities located contrary to the prudent operating standards'' because these terms are not precise enough for a safety rule. However, we think the situations they depict are relevant to deciding if equipment falls within the meaning of ''production operation'' under API RP 80. Also, we did not think additional use of the term ''for the first time,'' as two commenters suggested, would lessen the confusion the proposed limitation created. Finally, we did not see any need to exclude from production any equipment used in connection with a natural gas storage cavern or field because section 2.4.4 of API RP 80 indicates the term ''storage'' in the definition of ''production operation'' does not include underground storage of natural gas.

2. Limitation on Furthermost Gas Processing Plant Endpoint

Under section 2.2(a)(1)(A) of API RP 80, gathering ends at the inlet of the furthermost downstream natural gas processing plant not on a transmission line. We proposed the following limitation:

> Under section 2.2(a)(1)(A) of API RP 80, the endpoint may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.

The purpose of the limitation was to maintain consistency with prior DOT interpretations and State agency enforcement actions on gathering.

a. Comments

Coalition and Duke were concerned about the impact the closing of a gas processing plant could have on gathering line classifications. They asked us to clarify that the endpoint of gathering would not change if a plant closes temporarily for maintenance or market reasons.

West objected to placing the burden on operators to prove the need for further downstream processing. It thought the government should have the burden of proving further downstream processing is not needed. In addition, West thought we should allow economic reasons as proof.

b. PHMSA Response

We have not experienced a situation in which the closing of a gas processing plant affected a gathering line classification. Although closings of a few weeks for maintenance reasons would not trigger a classification change, longer closings could occur for a variety of reasons and the duration could be uncertain. So we decided not to make a general statement on how temporary plant closures would affect the end of gathering. Instead, when requested, we will determine the impact of closings on an individual basis as the need to do so arises. We expect certified State agencies with safety jurisdiction over gathering lines under 49 U.S.C. 60105 will do likewise.

Regarding West's burden of proof issue, it is not unusual for part 192 safety rules to include exceptions applicable only if operators can demonstrate certain conditions exist. For example, under § 192.479(c), operators do not have to protect aboveground pipelines from atmospheric corrosion if they demonstrate the corrosion will have certain characteristics. We require operators to demonstrate grounds for exceptions when they are the best source of information on which the exception is based. In the case of gathering lines, we think operators are the best source of information to demonstrate why further downstream processing is necessary to complete the gathering process.

As for the proof required in the demonstration, no doubt economics would be a factor in any decision involving further downstream processing. However, many of our prior interpretations have based the end of gathering on the first downstream processing plant. Maintaining consistency with this policy as far as possible is desirable for both government and industry. For this reason, we think any future variation should be based on the fundamental qualities of gas processing, which is best determined by engineering analyses rather than economic conditions, which are transitory. Therefore, the proposed limitation is unchanged in the final rule.

3. Limitation on Furthermost Treatment Facility Endpoint

Under section 2.2(a)(1)(B) of API RP 80, gathering ends at the outlet of the furthermost downstream gathering line gas treatment facility. We proposed the following limitation:

The endpoint under section 2.2(a)(1)(B) of API RP 80 applies only if no other endpoint identified under section 2.2(a)(1)(A) [processing], (a)(1)(C) [commingling], or (a)(1)(D) [compression] exists.

We intended this limitation to preclude manipulation of the transition from gathering to transmission by installing equipment used in gas treatment.

a. Comments

Coalition, supported by Duke, said the proposed limitation would make the furthermost treatment endpoint unusable, because processing, commingling, or compression is almost always upstream of a treatment facility. These commenters insisted gathering should continue downstream to a gas treatment facility endpoint no matter if compression, commingling, or processing occurs upstream. Coalition offered an alternative approach to preclude treatment manipulation:

(1) Use the following wording: ''The end of a gathering line * * * shall not be defined by the installation of one or more pieces of gas treating equipment at an extreme downstream location that is not justified by sound engineering and economic principles independent of the pipeline's regulatory classification.'' (2) Explain in the final rule preamble that this endpoint refers to a ''gas treating plant'' or similar facility and is not intended to be a simple piece of equipment like a separator or dehydrator (other than as can be shown, using sound engineering and economic principles, to be needed at that location to meet transmission pipeline specifications).

b. PHMSA Response

Section 2.2.1.2.2 of API RP 80 explains the meaning of a gas treatment facility under section 2.2(a)(1)(B). This provision describes gathering gas treatment (other than treatment in gas processing or compression) as involving significant stand-alone facilities (*e.g.*, a sulfur recovery or large dehydration facility). We think this explanation is sufficient to preclude possible manipulation of the treatment endpoint by installing a simple piece of treatment-related equipment, such as a separator or dehydrator. Thus, Coalition's alternative is not necessary and the proposed limitation is withdrawn.

4. Limitation on Furthermost Commingling Endpoint

Under section 2.2(a)(1)(C) of API RP 80, gathering ends at the furthermost downstream point where gas produced in the same production field or separate production fields is commingled. We proposed the following limitation:

If the endpoint is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other.

With no limit on the distance between separate production fields, a gathering line could continue endlessly, causing reclassification of pipelines from transmission to gathering.

a. Comments

Coalition, Duke, and West said the proposed limitation was not flexible enough to account for future acquisitions and use of maturing fields. Duke said its existing commingled fields were less than 50 miles apart. Although Coalition thought some commingled fields were 125 miles apart, it did not cite an actual example. Coalition and Duke recommended allowing case-by-case regulatory approvals of longer distances based on sound engineering and economic reasons.

b. PHMSA Response

Because, Duke, the largest gas gathering line operator in the U.S., said the proposed 50-mile limit would be adequate for its current systems, the proposed 50-mile limit is unchanged in the final rule. We did not adopt Coalition's request to change the limit to 125 miles because it did not provide any examples of an existing system where the 50-mile limit would be too restrictive. However, to provide flexibility, the final rule allows operators to petition PHMSA, under the procedures in 49 CFR § 190.9, to find a longer limit is justified in a particular case.

5. Limitation on Furthermost Compressor Endpoint

Under section 2.2(a)(1)(D) of API RP 80, gathering ends at the outlet of the furthermost downstream compressor station used to lower gathering line operating pressure to facilitate deliveries into the pipeline from production operations or to increase gathering line pressure for delivery to another pipeline. We proposed the following limitation:

The endpoint may not extend beyond the furthermost downstream compressor used to increase gathering line pressure for delivery to another pipeline.

This limitation is consistent with our past interpretations.

a. Comment

Coalition agreed with the proposed limitation, but asked us to clarify delivery to ''another pipeline'' does not mean delivery to another gathering line.

b. PHMSA Response

Section 3.2.8 of API RP 80 says, ''the definition of gathering line did not directly address the issue of one operator's gathering line beginning or ending with a connection to another operator's gathering line.'' Based on this clarification, we believe the term ''another pipeline'' in section 2.2(a)(1)(D) of API RP 80 does not mean delivering to another gathering line.

B. Defining ''Regulated Onshore Gathering Line''

We proposed to change how part 192 applies to onshore gathering lines outside inlets of the Gulf of Mexico by making the rules fit the level of risk gathering lines present. The proposal would restrict rules to two categories of lines, Type A and Type B, and define these lines as ''regulated onshore gathering lines.'' A description of the proposed definition is in section II of this preamble.

1. Approach To Defining Regulated Lines

a. Comments

Columbia suggested we adopt a simpler definition of ''regulated onshore gathering line'' limited to lines in Class 3 and Class 4 locations and lines in Class 1 and Class 2 locations where a potential impact circle includes 20 or more dwellings. It said the alternative would be easier to understand and apply, and consistent with the scientific-based definition of ''high consequence area'' in § 192.903. PST also suggested a more straightforward approach under which gathering and transmission lines of similar pressures and operating conditions would be regulated alike, and other gathering lines would be regulated the same as distribution lines.

b. PHMSA Response

We did not adopt Columbia's alternative because it would apply the same classification method (potential impact circles with 20 or more dwellings) to high-pressure and low-pressure lines in Class 1 and 2 locations. If impact circles were applied to low-pressure lines in Class 1 and 2 locations, the circles would most likely be too small to include 20 or more dwellings. So the risk of low-pressure lines to fewer than 20 nearby dwellings would not be addressed.

PST's alternative parallels our proposal to regulate higher-risk gathering lines the same as transmission lines, but most transmission line rules are more stringent than appear to be necessary for lower-risk gathering lines. Also, gathering lines are not sufficiently similar to distribution lines to apply the same rules to both types of lines.

2. Identifying Regulated Lines by Potential Impact Circles

a. Comments

AGA and Dominion supported using potential impact circles to identify higher-risk regulated gathering, but said the population criteria (proposed 5 or more dwellings) should not be more stringent than the criteria applied to gas transmission lines (20 or more dwellings under § 192.903). Dominion also suggested allowing use of impact circles as an optional identification method for Type B lines, not just Type A lines as proposed.

NAPSR spotted an irregularity in using potential impact circles to identify Type A lines. Some smaller Type B lines (10 inches nominal diameter or less) uprated to operate above 20 percent of SMYS would lose their regulated status if operators use impact circles to identify Type A lines and the circles do not contain the minimum number of dwellings (5) found in the rectangles (300 ft x 1000 ft) previously used to identify the lines as Type B. Likewise, the use of impact circles could cause some currently regulated nonrural lines operating above 20% of SMYS to lose their regulated status, even though similarly situated Type B lines would remain regulated. Consequently, NAPSR suggested we adopt the proposed Type B rectangles and safety rules as the minimum standard of safety for all regulated lines.

b. PHMSA Response

The decision discussed below (in response to NAPSR's comment) to withdraw the proposal on using potential impact circles to identify Type A lines makes the AGA and Dominion comments moot. Nevertheless, we offer the following: Section 192.903 requires 20 or more dwellings in potential impact circles used to identify transmission line segments subject to integrity management rules. These rules apply to the identified segments in addition to other applicable transmission rules. In contrast, we did not propose to apply integrity management rules to Type A lines identified by circles with just 5 dwellings or more. So we do not consider the proposed 5-per-circle method to be more stringent than the 20-per-circle method used for integrity management.

We did not propose potential impact circles to identify Type B lines because for low-pressure lines the circles would most likely be too small to contain at least 5 dwellings. For this reason, they would not equate to the proposed method of 5 or more dwellings per 1000 feet. As further explained under subheading 4 of this section of the preamble, we did not adopt potential impact circles as a method to identify Type B lines.

We believe NAPSR recognized a serious equivalency problem in allowing use of the proposed impact circles to identify Type A lines. The outcome could easily be an unregulated gathering line operating above 20 percent of SMYS next to a regulated Type B line, with both lines exposing the same dwellings to risk. To avoid this situation, we are withdrawing the proposal to use potential impact circles to identify Type A lines. We did not adopt NAPSR's suggested remedy because the compliance cost of detecting 5 dwellings per 1000 feet would likely be disproportionate to the benefits, as discussed below under subheading 4 of this section of the preamble.

3. Identifying Regulated Lines by Operating Stress

a. Comment

Coalition said 20 percent of SMYS is too low to distinguish high-stress Type A lines from low-stress Type B lines. It recommended using 30 percent of SMYS as in §§ 192.935, 192.937, and 192.941 for integrity management and in §§ 192.505 and 192.507 for pressure testing because lines operating at less than 30 percent of SMYS may leak but not rupture.

b. PHMSA Response

To regulate the safety of rural gas gathering lines, PHMSA must consider various physical characteristics, including operating pressure, to decide which lines warrant safety regulation (49 U.S.C. 60101(a)(21)(B) and (b)(2)(A)). We proposed 20 percent of SMYS as indicative of onshore gathering lines whose operating pressure presents a significant enough risk in certain circumstances to warrant the same amount of regulation as transmission lines, except rules on integrity management and smart pig passage. The basis for this 20-percent threshold is the part 192 definition of ''transmission line,'' which includes pipelines other than gathering lines operating at 20 percent of SMYS or more. These pipelines must meet all applicable part 192 safety rules. Because Type A lines can pose risks similar to transmission lines, we do not think 30 percent of

SMYS would be an appropriate threshold for Type A lines.

4. Identifying Regulated Lines Outside Class 3 and 4 Locations by 5 Dwellings per 1000 Feet

a. Comments

Coalition, Dominion, and Duke believed frequently surveying slightly populated areas (Class 1 and 2 locations) to identify line segments with 5 dwellings per 1000 feet would dilute, rather than expand, public safety by diverting attention from heavily populated areas (Class 3 and 4 locations). Coalition and Duke also said because most operators do not have the proposed 5-per-1000 dwelling data, they would have to create a new survey process and train personnel to use it. To apply the 5-per-1000 process initially, Coalition believed operators would survey all their onshore gathering lines (rather than 25 percent as we estimated) at a cost of $99.5 million (four times our estimate). From then on, Coalition estimated operators would resurvey at least 65 percent of lines each year at a cost of over $12.9 million instead of our estimate of 15 percent at $3 million.

To improve cost effectiveness, Coalition recommended an alternative regulatory approach to identify regulated onshore gathering lines in areas outside Class 3 and 4 locations. This approach focuses only on lines in Class 2 locations and uses the following methods rather than 5 dwellings per 1000 feet:

- For Type A lines, areas within (1) a Class 2 location; or (2) a potential impact circle with a minimum radius of 150 feet including 5 or more dwellings.
- For Type B lines, an area 150 feet on either side of the centerline of any continuous 1-mile length of pipeline including more than 10 but fewer than 46 dwellings.
- In addition, for Type A lines, Duke supported our proposed sliding mile approach using 25 or more houses per mile.

Commenting on Coalition's approach, Equitable also recommended focusing only on Class 2 locations. But it advised allowing operators a wider choice of identification methods for Type B lines: Potential impact circles like Coalition recommended for Type A lines, our proposed 5-per-1000 method, or Coalition's sliding mile alternative. Equitable said expanding the options to include potential impact circles would allow operators with advanced mapping systems to use them for compliance.

NFGSC sought to add a cluster exception to the proposed 5-per-1000 method for Type B lines to avoid regulating substantial lengths of line posing little risk. It said a Type B gathering line might pass within 150 feet of 5 dwellings clustered near a highway intersection, but not pass near another dwelling for 1,000 feet in either direction. Under the proposed definition, the regulated segment would extend for up to 1,000 feet in each direction, but pose little risk beyond the cluster. NFGSC suggested the regulated segment should extend in each direction only 150 feet from the nearest dwelling in the cluster.

b. PHMSA Response

On further consideration of the proposal, we agree with commenters who suggested frequently searching for pockets of 5 dwellings per 1000 feet in long, thinly populated Class 1 locations, which itself has at most 10 dwellings per mile, does not appear to be a reasonable use of available resources. So we are withdrawing the proposal to define certain lines in Class 1 locations as either Type A or Type B lines. However, as stated in the SNPRM, we are considering amending 49 CFR part 191 to collect reports of gathering line incidents in rural areas. If those reports indicate the risk of gathering lines in Class 1 locations is unacceptable, we will consider the need to expand our gathering line rules to include segments of or all lines in Class 1 locations.

We also think the burden of frequently surveying lines in Class 2 locations to look for line segments with 5 dwellings per 1000 feet is not the least costly way to tackle the risks involved with Type A lines. Thus we are adopting instead the commenters' recommendations to identify Type A lines outside Class 3 and 4 locations as lines in Class 2 locations. Most areas outside Class 3 and 4 locations with a population density of 5 dwellings per 1000 feet are found in Class 2 locations. Also, focusing on Class 2 as a whole, rather than by segments, is a clear and concise risk identification method. It has the advantage of allowing use of customary survey methods, eliminating the need for operators to devise new methods and provide additional training. Our proposed sliding mile approach with 25 or more houses per mile would have some of the same drawbacks as the 5 per 1000 approach. So it too is withdrawn. The change to Class 2 locations appears in final § 192.8(b)(2).

Coalition's recommendation to allow use of potential impact circles with a minimum radius of 150 feet to identify Type A line segments in Class 2 locations would not cure the irregularity NAPSR recognized. In some cases, the practical effect of the minimum radius would simply be a threshold density of 5 dwellings per 300 feet. This density would still be less stringent than the threshold of 5 dwellings per 1000 feet we proposed for Type B lines.

Because Type B lines operate at less than 20 percent of SMYS, they are not likely to have potential impact circles large enough to include at least 5 dwellings. So for Type B lines, the impact circle method does not equate to the proposed 5-per-1000 method we proposed for Class 2 locations. Nor do we think requiring impact circles to have a minimum radius of 150 feet, as commenters suggested, would cure the irregularity NAPSR recognized. So we did not adopt Equitable's comment to allow use of a potential impact circles with a minimum radius of 150 feet for Type B lines.

However, we favor Equitable's idea of offering operators more than one way to identify Type B lines outside Class 3 and 4 locations. As an alternative to the 5-per-1000 method, Coalition and Equitable suggested a variation of Class 2 criteria in which the sliding mile would extend only 150 feet on either side of the centerline instead of 220 yards. Because the potential impact of lines operating is less than 20 percent of SMYS is closer to 150 feet than 220 yards, we think this suggestion is reasonable. We also think small operators or operators who do not have Class 2 survey data may want to use the proposed 5-per-1000 method to minimize regulated mileage. So it remains an option in final § 192.8(b)(2). Also, operators well acquainted with Class 2 location surveys may prefer to treat all low-stress gathering lines in Class 2 locations as Type B lines. Thus, final § 192.8(b)(2) allows this option as well.

Regarding NFGSC's comment, § 192.5(c)(2) provides the following cluster exception for Class 2 and 3 locations: ''When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.'' As NFGSC recommended, we think a similar exception is appropriate for Type B lines identified by any of the options. The exception is in final § 192.8(b)(2).

V. Safety Requirements

A. Applying Operator Qualification (OQ) Rules to Type A Lines Outside Class 3 and 4 Locations

Under proposed § 192.9(c), the safety rules now applicable to nonrural gathering lines would apply to Type A regulated onshore gathering lines. These rules include all part 192 rules for gas transmission lines, except the rules in § 192.150 on passage of smart pigs and in subpart O on integrity management. Consequently, the proposed rules would require operators to comply with OQ rules in subpart N on Type A lines, no matter where the lines are located.

1. Comments

Coalition and Duke said because most gathering incidents are caused by excavation damage or corrosion rather than operator error, application of OQ rules outside Class 3 and 4 locations would impose significant costs with no proportionate reduction in risk. Duke reasoned compliance would be very costly because, for efficient use of personnel, operators would apply OQ rules to all lines in a gathering system not just to regulated segments. These commenters recommended we drop the proposal to require OQ rules for Type A lines outside Class 3 and 4 locations. In addition, Coalition recommended we collect incident data on regulated lines, and if operator error contributes noticeably to incidents, consider extending the OQ rules at that time.

2. PHMSA Response

In response to Coalition's and Duke's comments, PHMSA again reviewed the GPA study results that were submitted to the TPSSC.[3] This study looked at incidents[4] reported by 40 companies representing an aggregate 171,628 miles of non-regulated onshore gas gathering and found 1 incident attributable to human error. PHMSA notes that other operator qualification factors may indirectly contribute to pipeline failures. Furthermore, Congress directed DOT to establish regulations for OQ programs on pipelines. Congress also directed pipeline facility operators to develop and adopt a qualification program should DOT fail to prescribe standards and criteria. Congress further allowed DOT and State pipeline safety agencies to waive or modify any OQ requirements if not inconsistent with pipeline safety laws (49 U.S.C. 60131(e)(5) and (f)). Thus, Congress recognized that compliance with OQ regulations may not be suitable in all situations. In consideration of this data and Congress' intent, PHMSA modified the requirements of subpart N for Type A gathering lines in Class 2 locations. This change will allow operators of Type A lines in Class 2 locations to describe the processes they have in place to ensure that the personnel performing operations and maintenance activities are qualified. Because Congress directed operators to have OQ programs, this change should not impose any additional administrative costs.

B. Applying Safety Requirements to Lines ''Otherwise Changed''

1. Comment

Commenting on proposed § 192.9(d)(1), NFGSC considered the term ''otherwise changed'' unnecessary and vague. It asked us to drop the term unless we clearly explain its meaning.

2. PHMSA Response

Use of the term ''otherwise changed'' in proposed § 192.9(d)(1) parallels its use in existing § 192.13(b). This latter section, which has been part of part 192 since its initial publication in 1970, provides:

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

Though not defined in part 192, ''otherwise changed'' refers to a substantial physical alteration of a pipeline facility as opposed to a repair or restoration.

C. Compliance Times

Under proposed § 192.9(e)(1), design, installation, construction, initial inspection, and initial testing requirements would not apply to new, replaced, relocated, or otherwise changed lines until 1 year after publication of the final rule. Under proposed § 192.9(e)(2), the following compliance deadlines for lines not previously subject to part 192 would apply:

Requirement	Proposed compliance deadline
Control corrosion under subpart I.	2 years after final rule takes effect.
Prevent excavation damage under § 192.614.	6 months after final rule takes effect.
Establish MAOP under § 192.619.	6 months after final rule takes effect.
Install line markers under § 192.707.	1 year after final rule takes effect.
Educate public under § 192.616.	1 year after final rule takes effect.
Other requirements for Type A lines.	2 years after final rule is published.

PHMSA proposed the shorter timelines for provisions that require less time to implement, such as damage prevention. It proposed longer time frames for provisions that may require more time to procure and install materials.

Lastly, as proposed in § 192.9(e)(3), if an onshore gathering line becomes regulated because of a change in class location or an increase in dwelling density, the operator would have 1 year to comply with applicable requirements.

1. Comments

Coalition requested at least 1 additional year to complete training for and to carry out initial classifications if we adopted the Coalition's alternatives to the 5 per 1000 proposal (described in section IV. B. 4. of this preamble). AGA thought operators would need 2 years to complete the proposed classifications, and 4 years for full compliance. Dominion believed most operators would need 3 years for classifications, and large operators would need 4 years to meet corrosion control requirements. Duke said compliance times for large operators should be about twice as long as proposed, and 5 years for full compliance if operators have to determine classifications based on 5 dwellings per 1000 feet.

For lines that become regulated because of a change in class location or dwelling density, Columbia recommended allowing 2 years to meet the proposed safety requirements. It said this timeframe—1 year longer than we proposed—would be consistent with the time allowed for confirmation or revision of MAOP under § 192.611.

2. PHMSA Response

On the whole, comments indicated the proposed compliance times would not allow enough time to complete initial classifications and assure all regulated lines are in compliance. Since the final rule does not mandate 5 per 1000 surveys, we adopted Coalition's comment and, in final § 192.9(e)(2), added 1 year to the proposed times to allow more time for classifications. This change results in 3 years for full compliance. If an operator finds it needs more time final § 192.9(e)(2) allows operators to petition for more time on a case-by-case basis. For consistency with the time allowed for corrosion control, in final § 192.9(e)(2), we added 1 month to the time proposed for compliance

[3] The results of this study were presented at the February 2004 meeting of PHMSA's Technical Pipeline Safety Standards Advisory Committee.

[4] The GPA used the following criteria to define incidents for the informal study:

(1) Death or injury;

(2) Evacuation;

(3) Minor property damage ($5,000–$25,000);

(4) Major property damage (over $25,000).

with ''other requirements for Type A lines.''

After initial classifications, we expect most class location or dwelling density changes would cause only short segments of lines to become newly regulated. The bulk of these changes will probably affect Type B lines, requiring compliance with only a few part 192 safety rules. Operators could largely meet these requirements by folding the segments into their existing programs. In these cases, allowing 2 years for compliance as Columbia suggested does not appear necessary. However, if Type A lines are affected, operators would have to comply with many more requirements. Therefore, for Type A lines, final § 192.9(e)(3) allows 2 years for compliance.

D. Corrosion Control

1. Comment

Regarding proposed §§ 192.9(c) and (d)(2)), PSCWV said where cathodic protection is impractical, operators should have to survey the line for leaks each calendar year, not to exceed 15 months, using gas detection equipment.

2. PHMSA Response

We did not adopt this comment because the SNPRM did not include a proposal to require leak surveys where cathodic protection is impractical. In such cases, which should be few, operators may petition PHMSA or a State agency under 49 U.S.C. 60118 to waive applicable requirements, if not inconsistent with pipeline safety. PSCWV may have been concerned about situations in which § 192.465(e) requires operators to reevaluate unprotected piping but it is impractical to perform an electrical survey to determine the need for cathodic protection. In these situations, § 192.465(e) allows use of alternative means if they include review and analysis of leak repairs and other relevant information.

E. Determining MAOP

For any gathering line part 192 regulates for the first time on and after the effective date of this final rule, proposed §§ 192.619(a)(3) and (c) would allow the operator to determine the line's MAOP based on the line's highest actual operating pressures during the preceding 5-year period.

1. Comment

Coalition recommended we also apply the proposed rules to transmission lines part 192 regulates for the first time because of the final rule.

2. PHMSA Response

Although we expect few reclassifications of gathering to transmission lines, we agree any newly regulated transmission lines should have the same MAOP options as gathering lines. So we adopted Coalition's comment. For simplicity, we based the pressure date in the table in final § 192.619(a)(3) on the publication date of the final rule rather than the first day of the month preceding the publication date as proposed.

F. Editorial Changes

The proposed definition of ''regulated onshore gathering line'' distinguished Type A metallic lines by whether the MAOP produces a hoop stress of 20 percent or more of SMYS. In most cases, determining operating stress level is not a problem. However, on some older lines, the stress level corresponding to MAOP may be unknown because a pipe characteristic relevant to calculating stress, such as SMYS or wall thickness, is unknown. Subpart C of part 192 provides options to deal with these uncertainties. Final § 192.8(b) provides that operators are to apply applicable provisions in subpart C if the stress level is unknown.

The proposal to amend § 192.9 to require operators of Type B lines to control corrosion according to subpart I requirements did not specifically refer to subpart I requirements applicable to transmission lines. Final § 192.9(d)(2) makes it clear Type B lines are to meet transmission line requirements.

We proposed to amend § 192.452 to clarify how subpart I requirements specifically applicable to pipelines installed before or after certain past dates would apply to regulated onshore gathering lines existing when the final rule takes effect and not previously subject to subpart I (lines in rural locations). Final § 192.452(b) extends this provision to any onshore gathering line that becomes a regulated onshore gathering line because of an increase in population.

We have made some wording changes in final §§ 192.452 and 192.619 to use more plain language. These non substantive wording changes do not change any of the proposed or existing requirements in these sections.

VI. Regulatory Analyses and Notices

Privacy Act

Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477) or you may visit *http://dms.dot.gov.*

Executive Order 12866 and DOT Policies and Procedures

This rulemaking is not a significant regulatory action under Section 3(f) of Executive Order 12866 (58 FR 51735; Oct. 4, 1993). Therefore, the Office of Management and Budget (OMB) has not received a copy of this rulemaking to review. This rulemaking is also not significant under DOT regulatory policies and procedures (44 FR 11034: February 26, 1979).

PHMSA prepared a Regulatory Evaluation of this rulemaking and a copy is in Docket No. PHMSA–1998–4868. The evaluation concludes that there will be a net cost savings from implementing this final rule. The savings result from reducing the regulatory burden currently imposed on regulated gas gathering lines by establishing a tiered approach to safety requirements. PHMSA estimates that the total amount of gas gathering pipeline mileage that will be subject to part 192 will be about the same after implementing this rulemaking as it is now. However, requirements applicable to approximately three fourths of the regulated gathering line mileage, that which poses less public safety risk, will be reduced compared to the requirements now applicable to regulated lines. This proposal will result in a total cost of $26.54 million over a 20-year period. PHMSA estimates that the benefit of reducing the frequency of gas gathering pipeline incidents that have public safety consequences will cause a net benefit that is consistent with the increased regulatory burden.

Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), PHMSA must consider whether rulemaking actions would have a significant economic impact on a substantial number of small entities.

This rulemaking will affect operators of gas gathering pipelines. This rulemaking refines the definition of gas gathering pipelines subject to regulation and establishes a tiered regulatory structure, under which regulated gas gathering lines posing less risk will be subject to only some of the requirements now applied to all regulated gathering lines. PHMSA estimates that the overall economic effect of this regulation will be a net reduction in costs to operators.

At present, many operators of such pipelines are subject to federal safety regulation. The particular portions of their pipeline that are subject to regulation may change, in some cases, due to the changes in the definition, but the economic impact on these operators is expected to be a net reduction in costs, consistent with the regulatory analysis.

There may be some operators of gas gathering pipelines that are not now subject to safety regulations that will become so because portions of their pipeline will meet the criteria in the new definition for regulated gas gathering lines. These companies will experience added costs. The costs will depend on the risk posed by their pipelines. The number of companies expected to come under safety regulation for the first time is approximately 25, some of which may be small entities. In this SNPRM, however, PHMSA invited comments specifically on this estimate, but received no comments. Nevertheless, PHMSA believes the estimate may be too high. The Small Business Administration (SBA) also reviewed the SNPRM analysis and the comments filed in response to the SNPRM. The SBA discussed the SNPRM with its constituents and it resulted in the SBA providing favorable comments. Based on these facts, only a few companies will experience increased costs, and PHMSA believes that there will not be a significant economic impact on a ''substantial'' number of small entities.

The regulatory flexibility analysis accompanies the regulatory evaluation and is in the docket for review.

Executive Order 13175

PHMSA has analyzed this rulemaking according to the principles and criteria contained in Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Because the rulemaking will not significantly or uniquely affect the communities of the Indian tribal governments nor impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

Paperwork Reduction Act

This rulemaking contains information collection requirements applicable to operators of regulated onshore gas gathering lines. As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), PHMSA submitted a paperwork analysis to the Office of Management and Budget for its review. A copy of the analysis is in the docket. The OMB control numbers are: OMB No. 2137–0049 (recordkeeping under 49 CFR part 192) and OMB No. 2137–0579 (drug and alcohol testing under 49 CFR part 199).

For Type B regulated onshore gathering lines, operators will have to comply with part 192 information collection requirements regarding corrosion control, damage prevention programs, and public education programs. For Type A regulated onshore gathering lines, operators will have to comply not only with these requirements but also with others under various part 192 rules applicable to gas transmission lines. All operators of onshore gathering lines that are regulated will have to comply with the information collection requirements in 49 CFR part 199 concerning drug and alcohol testing. The small operators while required to collect test information, do not have to send reports annually and therefore are excluded from the reporting burden estimates but not the reporting estimates.

As explained above in section III of this preamble, gas gathering lines in non-rural locations are currently subject to PHMSA's safety regulations. The number of gathering line operators subject to regulation varies by year as pipelines are brought, taken out of service, and as changes occur in the boundaries of non-rural locations. Currently there are 284 onshore natural gas gathering pipeline operators subject to PHMSA safety regulation.

At present, all 284 of these operators are required to comply with part 192 rules applicable to transmission lines, including information collection requirements. The specific portions of these operators' gathering lines that are subject to part 192 regulations may change as a result of the final rule. Some portions may no longer be regulated, while others could become Type A or Type B lines. For Type B lines, the part 192 information collection burden will be significantly reduced, because Type B lines will be subject to far fewer part 192 regulations. The net effect on the paperwork burden faced by these 284 operators is thus expected to be a reduction. However, the magnitude of this reduction is difficult to estimate because PHMSA lacks the data necessary to determine which portions of operators currently regulated gathering lines will continue to be regulated by part 192 and which portions will become Type A or Type B lines.

Under the final rulemaking, some operators of gas gathering lines in rural locations could become subject to part 192 regulations for the first time. PHMSA estimates that no more than 25 operators will be newly subject to part 192 regulations as a result of this final rule. These operators will be required to comply with part 192 regulations proposed for Type A and Type B lines and with part 199 drug and alcohol testing regulations, including associated information collection requirements.

PHMSA's estimate of the paperwork burden on these newly-regulated operators is an average of approximately 40 hours per year. Much of this time will involve clerical personnel, but some involvement by managers and technical personnel will be required. At an estimated average hourly rate of $75 the estimated cost for 25 operators of this new paperwork burden, is $75,000.

PHMSA expects that this increase in cost for newly-regulated operators will be more than offset by the reduction in paperwork burden associated with currently regulated gas gathering lines that become either unregulated or Type B lines, as described above. Thus, the overall paperwork impact will be a small reduction.

Unfunded Mandates Reform Act of 1995

This rulemaking does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of $100 million or more to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the rulemaking.

National Environmental Policy Act

PHMSA has analyzed this rulemaking for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*). Because the rulemaking will require limited physical modification or other work that will disturb pipeline rights-of-way, PHMSA has determined the rulemaking is unlikely to significantly affect the quality of the human environment. Much of the pipeline mileage that will be subject to this final rule is already regulated, and no new actions likely to affect the environment are adopted for currently regulated lines. Also much of the existing rural mileage that become regulated under this final rule is already equipped with cathodic protection and location markers, the two requirements that will involve any installation/ modification work along the pipeline. An environmental assessment document is available for review in the docket. By requiring operators to participate in damage prevention programs and follow the applicable requirements for corrosion control, it may be expected that the number of failures on gathering lines will be reduced. Since gathering lines often contain gas streams laden with condensates and natural gas liquids (NGL's), the reduced number of failures also means a reduced number of spills of these liquids.

Executive Order 13132

PHMSA has analyzed this rulemaking according to the principles and criteria contained in Executive Order 13132 (''Federalism''). In its meetings with state agency officials on gathering lines, PHMSA discussed Federalism issues. None of the rules (1) Has substantial direct effects on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government; (2) impose substantial direct compliance costs on State and local governments; or (3) preempt state law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

Executive Order 13211

Executive Order 13211 (May 18, 2001; 66 FR 28355) requires Federal agencies to prepare a statement of energy effects to ensure that agencies weigh and consider the effects of governmental regulations on the supply, distribution, and use of energy. This statement constitutes the required statement of energy effects for the final rule redefining gas gathering lines and establishing the scope of safety regulations applicable to them.

The Department of Energy (DOE) expressed concerns about the potential adverse effect on the nation's energy supply derived from ''marginal well'' [5] production in the Alaska, Rocky Mountain, and Appalachian regions of the United States. Production from marginal wells represents approximately 10% of the domestic gas supply.[6]

To better understand the potential impact of changing the gas gathering definition and applying a risk-based approach, PHMSA conducted a study in West Virginia to determine if reclassification would occur as a result of applying the new definitions, to compare the effect on the amount of regulated mileage by applying the new ''regulated segment'' criteria, and to evaluate the expected cost increase/reductions expected by applying tiered risk-based compliance activities. West Virginia operators were selected for the study as a representative sample of marginal well production. In the sample study, PHMSA found that the concept of applying a risk-based approach to regulating gas gathering for pipeline safety purposes is viable. The gas gathering definitions will not cause significant reclassification of pipelines from a gathering classification to a transmission or distribution classification. Redefining the areas that PHMSA regulates will focus operator and regulatory resources on areas that could have detrimental consequences to the public, in the event of a pipeline failure. Regulatory compliance activities driven by risk will reduce operating and maintenance compliance costs for gathering lines operating at lower stress levels. Given these facts, current and future domestic natural gas production should not be impacted in a negative manner as a result of the final rule.

As described in more detail in the related regulatory analysis, the operators of some gas gathering pipelines will experience a reduction in costs to comply with safety regulations. This reduction in costs, if shared with operators of producing natural gas wells, could result in some wells operating beyond what would now be their economic end-of-life. This could result, over time, in more natural gas being produced for U.S. consumption than would be the case absent this change. PHMSA also discussed this final rule with the DOE and received no negative comments.

Based on the above considerations, and discussions with the DOE, PHMSA has determined that there will be no significant adverse impact on energy supply, distribution or prices as a result of implementing this final rule.

List of Subjects in 49 CFR Part 192

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

■ For the reasons discussed in the preamble, PHMSA amends 49 CFR part 192 as follows:

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

■ 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; and 49 CFR 1.53.

■ 2. In § 192.1,

■ a. Revise the section heading,

■ b. Revise paragraph (b)(4),

■ c. Remove paragraph (b)(5), and

■ d. Redesignate paragraph (b)(6) as (b)(5).

The changes read as follows:

§ 192.1 What is the scope of this part?

* * * * *

(b) * * *

(4) Onshore gathering of gas—

(i) Through a pipeline that operates at less than 0 psig (0 kPa);

(ii) Through a pipeline that is not a regulated onshore gathering line (as determined in § 192.8); and

(iii) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612.

* * * * *

■ 3. In § 192.7, revise the section heading, and in paragraph (c)(2) amend the table of referenced material by redesignating items (B)(4) and (B)(5) as (B)(5) and (B)(6) and adding an a new item (B)(4) to read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

* * * * *

(c) * * *

(2) * * *

Source and name of referenced material	49 CFR reference
B. * * *	* * *
(4) API Recommended Practice 80 (API RP 80) ''Guidelines for the Definition of Onshore Gas Gathering Lines'' (1st edition, April 2000)	§ 192.8

* * * * * * *

[5] A marginal well is generally defined as a well that produces less than 60,000 cubic feet of gas per day.

[6] ''Interstate Oil and Gas Compact Commission, Marginal Oil and Gas: Fuel for Economic Growth (2003 Edition).''

■ 4. Add a new § 192.8 to read as follows:

§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

(a) An operator must use API RP 80 (incorporated by reference, see § 192.7), to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the onshore gathering line is a regulated onshore gathering line under paragraph (b) of this section.

(1) The beginning of gathering, under section 2.2(a)(1) of API RP 80, may not extend beyond the furthermost downstream point in a production operation as defined in section 2.3 of API RP 80. This furthermost downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is involved in the processes of ''production and preparation for transportation or delivery of hydrocarbon gas'' within the meaning of ''production operation.''

(2) The endpoint of gathering, under section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.

(3) If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR § 190.9).

(4) The endpoint of gathering, under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthermost downstream compressor used to increase gathering line pressure for delivery to another pipeline.

(b) For purposes of § 192.9, ''regulated onshore gathering line'' means:

(1) Each onshore gathering line (or segment of onshore gathering line) with a feature described in the second column that lies in an area described in the third column; and

(2) As applicable, additional lengths of line described in the fourth column to provide a safety buffer:

Type	Feature	Area	Safety buffer
A	—Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is more than 125 psig (862 kPa).	Class 2, 3, or 4 location (*see* § 192.5)	None.
B	—Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is 125 psig (862 kPa) or less.	*Area 1.* Class 3 or 4 location *Area 2.* An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location. (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings. (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continous 1000 feet (305 m) of pipeline and including 5 or more dwellings.	If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2 (b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.

■ 5. Revise § 192.9 to read as follows:

§ 192.9 What requirements apply to gathering lines?

(a) *Requirements.* An operator of a gathering line must follow the safety requirements of this part as prescribed by this section.

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in § 192.150 and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in § 192.150 and in subpart O of this part. However, an operator of a Type A regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) *Type B lines.* An operator of a Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines;

(3) Carry out a damage prevention program under § 192.614;

(4) Establish a public education program under § 192.616;

(5) Establish the MAOP of the line under § 192.619; and

(6) Install and maintain line markers according to the requirements for transmission lines in § 192.707.

(e) *Compliance deadlines.* An operator of a regulated onshore gathering line must comply with the following deadlines, as applicable.

(1) An operator of a new, replaced, relocated, or otherwise changed line must be in compliance with the applicable requirements of this section by the date the line goes into service, unless an exception in § 192.13 applies.

(2) If a regulated onshore gathering line existing on April 14, 2006 was not

previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the line listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:

Requirement	Compliance deadline
Control corrosion according to Subpart I requirements for transmission lines.	April 15, 2009.
Carry out a damage prevention program under § 192.614.	October 15, 2007.
Establish MAOP under § 192.619.	October 15, 2007.
Install and maintain line markers under § 192.707.	April 15, 2008.
Establish a public education program under § 192.616.	April 15, 2008.
Other provisions of this part as required by paragraph (c) of this section for Type A lines.	April 15, 2009.

(3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section.

■ 6. In § 192.13,

■ a. Revise the section heading, and

■ b. Revise paragraphs (a) and (b), to read as follows:

§ 192.13 What general requirements apply to pipelines regulated under this part?

(a) No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless:

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

(2) The pipeline qualifies for use under this part according to the requirements in § 192.14.

Pipeline	Date
Offshore gathering line.	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006.	March 15 2007.
All other pipelines	March 12, 1971.

(b) No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
Offshore gathering line.	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006.	March 15, 2007.
All other pipelines	November 12, 1970.

* * * * *

■ 7. In § 192.452,

■ a. Revise the section heading,

■ b. Designate the existing text as paragraph (a),

■ c. Add ''*Converted pipelines.*'' as the heading of newly designated paragraph (a), and

■ d. Add a new paragraph (b), to read as follows:

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

(a) *Converted pipelines.* * * *

(b) *Regulated onshore gathering lines.* For any regulated onshore gathering line under § 192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under § 192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

■ 8. In § 192.619, revise the section heading and paragraphs (a)(3) and (c) to read as follows:

§ 192.619 What is the maximum allowable operating pressure for steel or plastic pipelines?

(a) * * *

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than § 192.612) after April 13, 2006. —Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.	March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

* * * * *

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with § 192.611.

Issued in Washington, DC, on March 10, 2006.

Brigham A. McCown,

Acting Administrator.

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