

area(s) which result from a CERCLA administrative order, a CERCLA or RCRA consent decree or a court order.

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Limitation of Future Contracting Alternate II (Start) (Apr 2004)

* * * * *

(d) During the life of this contract, including any options, the Contractor agrees that unless otherwise authorized by the Contracting Officer:

(1) It will not provide to EPA cleanup services (e.g., Emergency and Rapid Response Services (ERRS) contracts) within the Contractor's START assigned geographical area(s), either as a prime Contractor, subcontractor, or consultant.

(2) Unless an individual design for the site has been prepared by a third party, it will not provide to EPA as a prime contractor, subcontractor or consultant any remedial construction services at a site where it has performed or plans to perform START work. This clause will not preclude START contractors from performing construction management services under other EPA contracts.

(3) It will be ineligible for award of ERRS type activities contracts for sites within its respective START assigned geographical area(s) which result from a CERCLA administrative order, a CERCLA or RCRA consent decree or a court order.

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Limitation of Future Contracting Alternate III (ESAT) (Apr 2004)

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Limitation of Future Contracting Alternate IV (TES) (Apr 2004)

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Limitation of Future Contracting Alternate V (Headquarters Support) (Apr 2004)

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(c) The Contractor, during the life of this contract, will be ineligible to enter into a contract with EPA to perform response action work (e.g., Response Action Contract (RAC), Emergency and Rapid Response Services (ERRS), Superfund Technical Assistance and Removal Team (START), and Enforcement Support Services (ESS) contracts), unless otherwise authorized by the Contracting Officer.

* * * * *

Limitation of Future Contracting Alternate VI (Site Specific) (Apr 2004)

* * * * *

(d) During the life of this contract, including any options, the Contractor agrees that unless otherwise authorized by the Contracting Officer:

(1) It will not provide any Superfund Technical Assistance and Removal Team (START) type activities (e.g., START contracts) to EPA on the site either as a prime contractor, subcontractor, or consultant.

* * * * *

1552.215-76 [Removed and reserved]

■ 10. Remove and reserve section 1552.215-76.

1552.229-70 [Removed and reserved]

■ 11. Remove and reserve section 1552.229-70.

1552.237-73 [Removed and reserved]

■ 12. Remove and reserve section 1552.237-73.

[FR Doc. 05-21196 Filed 10-24-05; 8:45 am]

BILLING CODE 6580-50-P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 192 and 195

[Docket No. RSPA-04-16855; Amdt. 192-101 and 195-85]

RIN 2137-AD97

Pipeline Safety: Standards for Direct Assessment of Gas and Hazardous Liquid Pipelines

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

ACTION: Final rule.

SUMMARY: Under current regulations governing integrity management of gas transmission lines, if an operator uses direct assessment to evaluate corrosion risks, it must carry out the direct assessment according to PHMSA standards. In response to a statutory directive, this Final Rule prescribes similar standards operators must meet when they use direct assessment on certain other onshore gas, hazardous liquid, and carbon dioxide pipelines. PHMSA believes broader application of direct assessment standards will enhance public confidence in the use of direct assessment to assure pipeline safety.

DATES: This Final Rule takes effect November 25, 2005. Incorporation by reference of NACE Standard RP0502-2002 in this rule is approved by the Director of the Federal Register as of November 25, 2005.

FOR FURTHER INFORMATION CONTACT: L.M. Furrow by phone at 202-366-4559, by fax at 202-366-4566, by mail at U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590, or by e-mail at buck.furrow@dot.gov.

SUPPLEMENTARY INFORMATION:

I. Background

This Final Rule concerns direct assessment, a process of managing the effects of external corrosion, internal corrosion, or stress corrosion cracking

on pipelines made primarily of steel or iron. The process involves data collection, indirect inspection, direct examination, and evaluation. Operators use direct assessment not only to find existing corrosion defects but also to prevent future corrosion problems.

Congress recognized the advantages of using direct assessment on U.S. Department of Transportation (DOT) regulated gas, hazardous liquid, and carbon dioxide pipeline facilities. Section 14 of the Pipeline Safety Improvement Act of 2002 (Pub. L. 107-355; Dec. 17, 2002) directs DOT to issue regulations on using internal inspection, pressure testing, and direct assessment to manage the risks to gas pipeline facilities in high consequence areas. In addition, Section 23 directs DOT to issue regulations prescribing standards for inspecting pipeline facilities by direct assessment.

In response to the first statutory directive, Section 14, DOT's Research and Special Programs Administration (RSPA) ¹ published regulations in 49 CFR part 192, subpart O, that require operators to follow detailed programs to manage the integrity of gas transmission line segments in high consequence areas. Subpart O also requires an operator electing to use direct assessment in its integrity management program, to carry out the direct assessment according to §§ 192.925, 192.927, and 192.929, as appropriate.²

Sections 192.925, 192.927, and 192.929 cross-reference the American Society of Mechanical Engineers' (ASME), ASME B31.8S-2001, "Managing System Integrity of Gas Pipelines." ASME B31.8S-2001 describes a comprehensive process to assess and mitigate the likelihood and consequences of gas pipeline risks. In addition, § 192.925 cross-references a

¹ The Norman Y. Mineta Research and Special Programs Improvement Act (Pub. L. 108-426, 118; November 30, 2004) reorganized RSPA into two new DOT administrations: the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Research and Innovative Technology Administration. RSPA's regulatory authority over pipeline and hazardous materials safety was transferred to PHMSA.

² The standard on external corrosion direct assessment (§ 192.925) requires operators to integrate data on physical characteristics and operating history, conduct indirect aboveground inspections, directly examine pipe surfaces, and evaluate the effectiveness of the assessment process. Under the standard for direct assessment of internal corrosion (§ 192.927), operators must predict locations where electrolytes may accumulate in normally dry-gas pipelines, examine those locations, and validate the assessment process. The standard for direct assessment of stress corrosion cracking (§ 192.929) involves collecting data relevant to stress corrosion cracking, assessing the risk of pipeline segments, and examining and evaluating segments at risk.

NACE International (NACE) standard, NACE Standard RP0502-2002, "Pipeline External Corrosion Direct Assessment Methodology." NACE Standard RP0502-2002 describes a step-by-step process for identifying and addressing external corrosion activity, repairing defects, and taking remedial action. Other parts of §§ 192.925, 192.927, and 192.929 ensure operators use appropriate criteria in making direct assessment decisions.

II. Proposed Rules

In response to the second statutory directive, Section 23, PHMSA published a notice of proposed rulemaking (NPRM) (69 FR 61771; Oct. 21, 2004). The NPRM proposed standards for using direct assessment on any onshore gas pipeline made primarily of steel or iron and regulated by 49 CFR part 192 or onshore steel hazardous liquid or carbon dioxide pipeline regulated by 49 CFR part 195. Under proposed § 192.490, if an operator chooses to use direct assessment to evaluate the threat of external corrosion, internal corrosion, or stress corrosion cracking on a regulated onshore gas pipeline, the direct assessment would have to be done according to §§ 192.925, 192.927, or 192.929, as appropriate. For regulated hazardous liquid and carbon dioxide pipelines, proposed § 195.588 would

require similar action, except compliance with § 192.927 would not be required, because § 192.927 requirements are only suitable for dry gas pipelines.

III. Advisory Committee Recommendations

The Technical Pipeline Safety Standards Committee (TPSSC) and the Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC) considered the NPRM at meetings in Washington, DC, on December 14 and 15, 2004. The TPSSC, a statutorily mandated advisory committee, advises PHMSA on proposed safety standards and other policies concerning gas pipelines. The THLPSSC is a similar committee that provides advice about hazardous liquid and carbon dioxide pipelines. Each 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. A transcript of each committee's meeting is available in Docket No. PHMSA-98-4470.

After careful consideration of the NPRM, the THLPSSC voted unanimously to recommend the

following: (1) Adopt a single definition of direct assessment for use by hazardous liquid pipeline operators inside and outside high consequence areas; (2) state direct assessment standards directly in part 195, rather than by cross-referencing part 192 standards; (3) consider adopting the consensus standard under development by NACE for direct assessment of stress corrosion cracking; and (4) amend the integrity management rule (§ 195.452) to allow use of direct assessment without prior notice.

As a result of its deliberation, the TPSSC voted unanimously that proposed § 192.490 should not be applied to gas distribution lines. It also voted unanimously that the Final Rule should distinguish direct assessment from similar methods of assessing corrosion. Such a distinction would identify situations where similar methods of addressing corrosion are appropriate but are not regulated under the proposed direct assessment standard.

IV. Disposition of Comments and Advisory Committee Recommendations on Proposed Rules

We received written comments on the proposed rules from 19 sources. These sources are categorized as follows:

State pipeline safety agency	Pennsylvania Public Utility Commission.
Gas pipeline operators	Duke Energy Gas Transmission (Duke), El Paso Corporation (El Paso), Nicor Gas (Nicor), NiSource Corporate Services Company (Nisource), Pacific Gas & Electric Company (PG&E), Paiute Pipeline Company (Paiute), Puget Sound Energy (Puget), Southwest Gas Corporation (SWGAS).
Gas pipeline trade associations	American Public Gas Association (APGA), American Gas Association (AGA), Interstate Natural Gas Association of America (INGAA), Northeast Gas Association (NGA).
Gas pipeline industry committee	Gas Piping Technology Committee (GPTC).
Hazardous liquid pipeline trade associations	American Petroleum Institute (API), Association of Oil Pipe Lines (AOPL).
Nonprofit organizations	Cook Inlet Regional Citizens Advisory Council, Pipeline Safety Trust
Consultant	Glen F. Armstrong.

Only one commenter, the Cook Inlet Regional Citizens Advisory Council (Council), created by the Oil Pollution Act of 1990, supported the proposed rules without change. The Council welcomed the additional Federal standards because of the need to control pipeline corrosion. The remaining commenters' issues are stated below along with our disposition of those issues and the advisory committee's recommendations.

Is this rulemaking necessary? AGA, Duke, El Paso, GPTC, INGAA, NiSource, and Puget claimed the integrity management regulations for gas transmission lines (subpart O of part 192) satisfy the statutory directive to prescribe direct assessment standards. Taking a similar position, AOPL and

API contended that Congress did not intend direct assessment standards to apply outside integrity management regulations. To support this position, these commenters stated that Congress did not require operators to use direct assessment on pipelines outside integrity management regulations. They also pointed out that direct assessment was developed for use in integrity management programs.

Because the legislative history does not support the commenter's argument that direct assessment standards should apply only to pipelines subject to integrity management rules, PHMSA believes this rulemaking is necessary. It is reasonable to conclude Congress did not intend to restrict direct assessment standards to pipelines covered by

integrity management regulations. Unlike the first statutory directive concerning direct assessment, which applies only to pipeline facilities in high consequence areas, the second directive applies to pipeline facilities regardless of location. Also, the first and second directives appear in separate sections of the statute (Sections 14 and 23 of Pub. L. 107-355), with no apparent connection. Had Congress wanted to restrict direct assessment standards to pipelines covered by integrity management regulations, it could have expressly linked the second directive to the first or included the second directive in the same section as the first.

Is proposed § 192.490 appropriate for gas distribution lines? AGA, APGA,

Duke, El Paso, GPTC, INGAA, NGA, Nicor, NiSource, Paiute, and PG&E argued direct assessment was developed for gas transmission integrity management and has not been shown to be appropriate for gas distribution lines. They said the relevant technical data and experience do not show direct assessment would be effective on gas distribution lines. In addition, some of these commenters thought because gas distribution lines differ from gas transmission lines in design, operation, configuration, and location, direct assessment may be impractical on gas distribution lines. The many aboveground and belowground utility facilities—both in-service and abandoned—were thought to pose significant technical hurdles. The Pennsylvania Public Utility Commission and the Pipeline Safety Trust also questioned the suitability of direct assessment for gas distribution lines.

These comments came as a surprise to PHMSA because the two documents that are the mainstays of the proposed direct assessment standards, ASME B31.8S-2001 and NACE Standard RP0502-2002, can be interpreted to cover gas distribution lines. Each document states that it applies to onshore pipelines. Although neither document defines "pipeline," ASME's B31.8 Code, to which ASME B31.8S-2001 is a supplement, defines "pipeline" as "all parts of physical facilities through which gas moves in transportation." And "transportation of gas" is defined as the "gathering, transmission, or distribution of gas."

No matter how ASME B31.8S-2001 and NACE Standard RP0502-2002 are interpreted, the comments persuaded us that direct assessment, as depicted by these two documents, is not appropriate for gas distribution lines. Both ASME B31.8S-2001 and NACE Standard RP0502-2002, were developed during the rulemaking proceeding on gas transmission integrity management and in furtherance of that proceeding. Consequently, neither document was developed with a focus on gas distribution lines. Furthermore, although both documents apply to pipelines, they do not take full account of gas distribution line features as comments suggest they should to treat gas distribution lines appropriately.

Given these considerations and the TPSSC's unanimous recommendation that we not apply the proposed direct assessment standards to gas distribution lines, we decided to exclude distribution lines from final § 192.490. Removing "pipeline" from the proposed wording and adding "transmission line" in its place accomplishes this change.

Would the proposed standards discourage the voluntary use of corrosion control methods? AGA, Armstrong, Duke, El Paso, GPTC, INGAA, NGA, Nicor, NiSource, Paiute, PG&E, Puget, and SWGas were concerned the proposed standards (§§ 192.490 and 195.588) would discourage operators from voluntarily using corrosion control methods related to direct assessment on pipelines not subject to the integrity management regulations. Their concern stemmed from the difficulty of recognizing when direct assessment is being used. They said performance of any one of the four steps that constitute direct assessment could imply use of direct assessment and lead to disagreements with government inspectors over whether direct assessment is being used. For example, some commenters said performing a close interval electrical survey resembled the indirect examination step of direct assessment. Others thought examining buried pipe for corrosion could be considered the direct examination step. El Paso, INGAA, Nicor, and Armstrong suggested the Final Rule clarify that operators may use corrosion control methods related to direct assessment without having to meet the proposed direct assessment standards.

We recognize disagreements could arise over whether the use of a corrosion control method is part of the direct assessment process. However, we do not think such disagreements are likely to be serious enough to discourage operators from continuing to use such methods separately from direct assessment. To minimize potential disagreements, operators may explain in their corrosion control procedures the situations in which they use methods related to direct assessment separately from direct assessment.

In view of the commenters' concern, PHMSA has added provisions to final §§ 192.490 and 195.588 to clarify application of the direct assessment standards. The statement provides that the direct assessment standards do not apply to methods related to direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process. This change is consistent with the TPSSC's second recommendation.

Are the gas pipeline standards cross-referenced in proposed § 195.588 suitable for hazardous liquid and carbon dioxide pipelines? In their comments on proposed § 195.588, AOPL and API opposed cross-referencing §§ 192.925 and 192.929 primarily

because these standards refer to ASME B31.8S-2001. They argued ASME B31.8S-2001 was developed for natural gas transmission lines and without the involvement of hazardous liquid pipeline operators. They were also concerned that cross-referencing part 192 gas pipeline standards could lead to misunderstandings by hazardous liquid pipeline operators. The THLPSSC similarly opposed cross-referencing part 192 standards.

In developing the NPRM, we assumed the cross-referenced part 192 standards and their cross-references to ASME B31.8S-2001 would be suitable for hazardous liquid and carbon dioxide pipelines. However, the AOPL and API comments and the THLPSSC's recommendation have caused us to doubt that assumption. In addition, we are concerned that application of the part 192 direct assessment standards to hazardous liquid and carbon dioxide pipelines could present compliance problems. Contributing to this concern is the comment that ASME B31.8S-2001 was not developed with an eye to hazardous liquid pipelines. In fact, paragraph 1.1 of ASME B31.8S-2001 specifically states that the scope of ASME B31.8S-2001 is limited to "onshore pipeline systems * * * that transport gas."

Therefore, we decided not to include cross-references to part 192 standards or to ASME B31.8S-2001 in final § 195.588. Instead, final § 195.588 includes a complete statement of direct assessment standards, with cross-references only to NACE Standard RP0502-2002.

Should the integrity management regulations for hazardous liquid and carbon dioxide pipelines allow use of direct assessment without advance notice? The integrity management regulations for hazardous liquid and carbon dioxide pipelines (§ 195.452) prescribe three ways to assess pipeline integrity: internal inspection via a smart pig, pressure testing, and any other technology the operator demonstrates can provide an equivalent understanding of pipe conditions. However, before another technology, such as direct assessment may be used, the operator must notify PHMSA at least 90 days in advance (§§ 195.452(c)(1)(i)(C) and 195.452(j)(5)(iii)).

In contrast to § 195.452, the proposed direct assessment standards do not include a requirement to give 90 days' advance notice as a precondition to using direct assessment. We see no need to propose such a requirement since the current Part 192 direct assessment standards do not require operators to

give advance notice before using direct assessment.

In their comments on proposed § 195.588, AOPL and API suggested direct assessment of external corrosion should be listed directly in § 195.452 as a permissible method of integrity assessment. They believe that when external corrosion direct assessment is performed according to NACE Standard RP0502–2002, it is an acceptable use of “other technology” for which 90 days advance notice is no longer necessary. As discussed above under Advisory Committee Recommendations, the THLPSSC also favored listing direct assessment directly in § 195.452 as a recognized assessment method that would bypass the 90-day advance notice requirement.

The purpose of the 90 days advance notice requirement in § 195.452 is to provide time for PHMSA and State pipeline safety agencies to review technology other than pigging and pressure testing to learn what information the technology provides about pipe conditions. According to information on a PHMSA Web site (<http://primis.phmsa.dot.gov/iim/notifications.imd>), several operators have submitted notices of their intent to use direct assessment on hazardous liquid or carbon dioxide pipelines. In a majority of cases, there were no PHMSA or State government objections to the use of direct assessment. Objections were raised where the notification lacked information explaining how the direct assessment was to be performed.

When applied to direct assessment, we believe the 90-day advance notice requirement of § 195.452 is no longer useful and is inconsistent with the proposed rules. Direct assessment is now being used under the part 192 integrity management regulations without advance notice. As a result, government inspectors are fully aware of the direct assessment technology and the situations for which it is suited, making advance case-by-case review under § 195.452 unnecessary. In addition, requiring operators to follow prescribed standards when using direct assessment will remove the primary objection previously raised about operators’ advance notices—insufficient information to explain the method of assessment. Therefore, we are changing § 195.452(c)(1)(i)(C) and 195.452(j)(5)(iii) to allow use of direct assessment in accordance with final § 195.588 without 90 days advance notice.

What standard should apply to direct assessment of stress corrosion cracking on hazardous liquid and carbon dioxide pipelines? The NPRM proposed that

§ 192.929 be the standard for direct assessment of stress corrosion cracking on hazardous liquid and carbon dioxide pipelines. This standard relies largely on cross-references to ASME B31.8S–2001.

Besides their objections to cross-referencing part 192 standards and particularly ASME B31.8S–2001, AOPL and API suggested that we not adopt any standard for the direct assessment of stress corrosion cracking on hazardous liquid pipelines. They said because methods of detecting stress corrosion cracking are developing rapidly, direct assessment may not be the optimum technology for hazardous liquid pipelines. The THLPSSC recommended we consider adopting the consensus standard that NACE International was developing for direct assessment of stress corrosion cracking.

As explained above, we decided not to cross-reference directly or indirectly ASME B31.8S–2001 in final § 195.588, because the document is closely identified with gas pipelines. Consequently, since provisions of ASME B31.8S–2001 are an important part of the proposed stress corrosion standard, we have not included a direct assessment standard for stress corrosion cracking in final § 195.588. As the THLPSSC recommended, we will consider the recently published NACE Standard RP0204–2004, Stress Corrosion Cracking (SCC) Direct Assessment Methodology, for possible future rulemaking action. By removing the proposed cross-reference to § 192.929, final § 195.588 consists of the text of § 192.925 without its cross-references to ASME B31.8S–2001.

V. Editorial Changes

- Final §§ 192.490 and 195.588 do not include the proposed phrase “or to meet any requirement of this Subpart regarding that threat.” The phrase was used in the proposed rules to draw attention to situations in which operators might choose to use direct assessment. However, the phrase appears to be unnecessary and, according to comments, possibly confusing.

- Final § 192.490 clarifies that “direct assessment” means direct assessment as defined in § 192.903.³ This definition applies to “direct assessment” as it is

³ Section 192.903 defines “direct assessment” as “an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment’s integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.”

used in subpart O of part 192, including § 192.925, 192.927, and 192.929—the bases of the proposed direct assessment standards. Also, in final § 192.490, instead of using the proposed term “ferrous” to limit pipelines to which the direct assessment standards apply, we used “made primarily of steel or iron.” This change removes the possibility of confusion over the meaning of ferrous.

- We added a similar definition of “direct assessment” to § 195.553, which contains definitions applicable to subpart H of part 195, including final § 195.588. This addition satisfies the first THLPSSC recommendation. The definition of “external corrosion direct assessment,” which was proposed through the cross-reference to § 192.925, is also added to § 195.553.

- In final § 195.588, we substituted “pipeline segment” for the terms “covered segment” and “covered pipeline segment” to avoid the possibility that the definition of these terms in § 192.903—a segment of transmission pipeline located in a high consequence area—would unintentionally constrain the scope of final § 195.588. A footnote resolves a similar problem in final § 192.490.

- Section 192.925(b) provides that if coating damage is detected by external corrosion direct assessment, the operator must integrate that information with data gathered and integrated under certain other requirements (§§ 192.917(b) and 192.917(e)(1)). These other requirements, which involve evaluating and addressing risks besides corrosion, including third-party damage, apply only to gas transmission lines subject to the integrity management regulations in subpart O of part 192. Although the proposed direct assessment standards for other pipelines included cross-references to § 192.925, the NPRM did not address extending §§ 192.917(b) and 192.917(e)(1) to pipelines outside subpart O by virtue of the cross-references. The focus of the NPRM was strictly on using direct assessment to evaluate and address corrosion risks. Using direct assessment data to evaluate non-corrosion risks to pipeline integrity was not discussed. So it would be inappropriate to infer that the proposed references to § 192.925 meant that operators who voluntarily use external corrosion direct assessment on pipelines outside subpart O would also have to comply with §§ 192.917(b) and 192.917(e)(1). To ensure this possible inference does not affect the Final Rules, final §§ 192.490 and 195.588 exclude pipelines outside subpart O from the § 192.925(b) requirement related to integrating coating damage data. Nevertheless, for

hazardous liquid and carbon dioxide pipelines that are subject to the integrity management regulations in § 195.452, the detection of coating damage is an important factor to consider in the information analysis required by § 195.452(g) and the continual integrity evaluation required by § 195.452(j)(2).

VI. Regulatory Analyses and Notices

Executive Order 12866 and DOT Policies and Procedures. PHMSA does not consider this rulemaking to be 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 the Final Rule to review. PHMSA also does not consider this rulemaking to be significant under DOT regulatory policies and procedures (44 FR 11034; February 26, 1979).

PHMSA has evaluated the costs and benefits of this Final Rule and a copy of the evaluation is in the docket. The evaluation concludes operators will incur only minimal costs to comply with the Final Rule.

Regulatory Flexibility Act. Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), PHMSA must consider whether rulemaking actions have a significant economic impact on a substantial number of small entities. Based on the facts available about the anticipated impacts of this rulemaking, I certify that this rulemaking will not have a significant impact on a substantial number of small entities.

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 Final Rule 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. Operators have just recently begun to use direct assessment to assess the effects of corrosion on onshore gas transmission lines subject to the integrity management regulations in subpart O of part 192. The use of direct assessment on other pipelines regulated by part 192 or part 195 is voluntary. This Final Rule does not change this voluntary use status. It merely sets standards for performing direct assessment if operators choose to use it.

Pipeline operators covered by the Final Rule who choose to use direct assessment would have to prepare appropriate plans and procedures and

keep records as required by Section 7 of *NACE Standard RP0502-2002*. To help estimate the paperwork burden these operators would face, the NPRM invited comments on how many operators plan to use direct assessment voluntarily and what the burden hours and cost would be.

None of the commenters foresaw any voluntary use of direct assessment or commented on the potential paperwork burden. This result was not a surprise, for direct assessment is a new process and so far its use is mostly limited to gas transmission lines subject to subpart O of part 192. Under these circumstances, it is reasonable to expect that few, if any, operators will be affected by the Final Rule. So no net increase in paperwork burdens is likely from this Final Rule. For this reason, we believe that submitting an analysis of the burdens to OMB under the Paperwork Reduction Act is unnecessary.

Unfunded Mandates Reform Act of 1995. This Final Rule 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 the Final Rule for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*). Because the Final Rule affects only those operators that voluntarily use direct assessment and because it largely involves processes of data collection and evaluation, we have determined that it is unlikely to significantly affect the quality of the human environment. An Environmental Assessment is available for review in the docket.

Executive Order 13132. PHMSA has analyzed the Final Rule according to the principles and criteria contained in Executive Order 13132, "Federalism." No part of the rule (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) imposes substantial direct compliance costs on State and local governments; or (3) preempts State law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

Executive Order 13211. This Final Rule is not a "Significant Energy Action" under Executive Order 13211. It is not a significant regulatory action under Executive Order 12866 and is not likely to have a significant adverse effect

on the supply, distribution, or use of energy. Further, this rulemaking has not been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

List of Subjects

49 CFR Part 192

Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

49 CFR Part 195

Ammonia, Carbon dioxide, Incorporation by reference, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

■ In consideration of the foregoing, PHMSA amends 49 CFR parts 192 and 195 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. Add § 192.490 to read as follows:

§ 192.490 Direct assessment.

Each operator that uses direct assessment as defined in § 192.903 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard ¹
External corrosion	§ 192.925 ²
Internal corrosion in pipelines that transport dry gas.	§ 192.927
Stress corrosion cracking	§ 192.929

¹ For lines not subject to subpart O of this part, the terms "covered segment" and "covered pipeline segment" in §§ 192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed.

² In § 192.925(b), the provision regarding detection of coating damage applies only to pipelines subject to subpart O of this part.

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 3. The authority citation for part 195 continues to read as follows:

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

■ 4. In § 195.3(c), amend the table of referenced material by adding item G.(2) to read as follows:

§ 195.3 Matter incorporated by reference in whole or in part.

* * * * *
(c) * * *

Table with 2 columns: Reference and Section. Row 1: G. * * * (2) NACE Standard RP0502-2002 "Pipeline External Corrosion Direct Assessment Methodology" (2002). § 195.588

- 5. Amend § 195.452 as follows:
■ a. Redesignate paragraph (c)(1)(i)(C) as (c)(1)(i)(D);
■ b. Remove "or" from the end of paragraph (c)(1)(i)(B);
■ c. Redesignate paragraph (j)(5)(iii) as (j)(5)(iv);
■ d. Remove "or" from the end of paragraph (j)(5)(ii); and
■ e. Add new paragraphs (c)(1)(i)(C) and (j)(5)(iii) to read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

* * * * *

- (c) * * *
(1) * * *
(i) * * *
(C) External corrosion direct assessment in accordance with § 195.588; or
* * * * *
(j) * * *
(5) * * *
(iii) External corrosion direct assessment in accordance with § 195.588; or
* * * * *

■ 6. In § 195.553, add definitions for "direct assessment" and "external corrosion direct assessment (ECDA)" as follows:

§ 195.553 What special definitions apply to this Subpart?

* * * * *

Direct assessment means an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

External corrosion direct assessment (ECDA) means a four-step process that combines pre-assessment, indirect

inspection, direct examination, and post-assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

* * * * *

■ 7. Add § 195.588 to read as follows:

§ 195.588 What standards apply to direct assessment?

(a) If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion, you must follow the requirements of this section for performing external corrosion direct assessment. This section does not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

(b) The requirements for performing external corrosion direct assessment are as follows:

(1) General. You must follow the requirements of NACE Standard RP0502-2002 (incorporated by reference, see § 195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment.

(2) Pre-assessment. In addition to the requirements in Section 3 of NACE Standard RP0502-2002, the ECDA plan procedures for pre-assessment must include—

- (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;
(ii) The basis on which you select at least two different, but complementary, indirect assessment tools to assess each ECDA region; and
(iii) If you utilize an indirect inspection method not described in Appendix A of NACE Standard RP0502-2002, you must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(3) Indirect examination. In addition to the requirements in Section 4 of NACE Standard RP0502-2002, the procedures for indirect examination of the ECDA regions must include—

- (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;
(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination, including at least the following:

(A) The known sensitivities of assessment tools;

(B) The procedures for using each tool; and

(C) The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) For each indication identified during the indirect examination, criteria for—

(A) Defining the urgency of excavation and direct examination of the indication; and

(B) Defining the excavation urgency as immediate, scheduled, or monitored; and

(iv) Criteria for scheduling excavations of indications in each urgency level.

(4) Direct examination. In addition to the requirements in Section 5 of NACE Standard RP0502-2002, the procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE Standard RP0502-2002 provides guidance for criteria); or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE Standard RP0502-2002 provides guidance for criteria);

(iii) Criteria and notification procedures for any changes in the ECDA plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis you will reclassify and reprioritize any of the provisions specified in Section 5.9 of NACE Standard RP0502-2002.

(5) Post assessment and continuing evaluation. In addition to the requirements in Section 6 of NACE Standard UP 0502-2002, the procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in pipeline segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the pipeline segment at an interval less than that specified in

Sections 6.2 and 6.3 of NACE Standard RP0502-2002 (see Appendix D of NACE Standard RP0502-2002).

Issued in Washington, DC, on October 19, 2005.

Brigham A. McCown,
Acting Administrator, PHMSA.

[FR Doc. 05-21233 Filed 10-24-05; 8:45 am]

BILLING CODE 4910-60-P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 648

[Docket No. 031015257-3308-02 ; I.D. 101705B]

Fisheries of the Northeastern United States; Atlantic Surfclam and Ocean Quahog Fisheries; Suspension of Minimum Atlantic Surfclam Size Limit for Fishing Year 2006

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

ACTION: Temporary rule; suspension of the Atlantic surfclam minimum size limit.

SUMMARY: NMFS suspends the minimum size limit of 4.75 inches (120 mm) for Atlantic surfclams for the 2006 fishing year. This action is taken under the authority of the implementing regulations for this fishery, which allow

for the annual suspension of the minimum size limit based upon set criteria. The intended effect is to relieve the industry from a regulatory burden that is not necessary, as the majority of surfclams harvested are larger than the minimum size limit.

DATES: Effective January 1, 2006, through December 31, 2006.

ADDRESSES: Written inquiries may be sent to Patricia A. Kurkul, Regional Administrator, National Marine Fisheries Service, Northeast Regional Office, One Blackburn Drive, Gloucester, MA 01930-2298.

FOR FURTHER INFORMATION CONTACT: Brian R. Hooker, Fishery Policy Analyst, (978) 281-9220; fax (978) 281-9135.

SUPPLEMENTARY INFORMATION: Section 648.72(c) of the regulations implementing the Fishery Management Plan (FMP) for the Atlantic Surfclam and Ocean Quahog Fisheries allows the Administrator, Northeast Region, NMFS (Regional Administrator) to suspend annually, by publication of a notification in the Federal Register, the minimum size limit for Atlantic surfclams. This action may be taken unless discard, catch, and biological sampling data indicate that 30 percent of the Atlantic surfclam resource is smaller than 4.75 inches (120 mm) and the overall reduced size is not attributable to harvest from beds where growth of the individual clams has been reduced because of density-dependent factors.

At its June 2004 meeting, the Mid-Atlantic Fishery Management Council (Council) voted to recommend that the Regional Administrator suspend the minimum size limit for the 2005, 2006, and 2007 fishing years. In accordance with the provisions of the FMP, the Regional Administrator will publish the suspension of the surfclam minimum size if the proportion of undersized surfclams is under 30 percent of the total surfclam landings for each fishing year.

Commercial surfclam data for 2005 were analyzed to determine the percentage of surfclams that were smaller than the minimum size requirement. The analysis indicated that 6.8 percent of the overall commercial landings were composed of surfclams that were less than 4.75 inches (120 mm). Based on these data, the Regional Administrator adopts the Council's recommendation and suspends the minimum size limit for Atlantic surfclams from January 1, 2006, through December 31, 2006.

Classification

This action is authorized by 50 CFR part 648 and is exempt from review under Executive Order 12866. Authority: 16 U.S.C. 1801 et seq.

Dated: October 20, 2005.

Alan D. Risenhoover,
Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.
[FR Doc. 05-21302 Filed 10-24-05; 8:45 am]
BILLING CODE 3510-22-S

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 StandardsAGENCY: 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.

FOR FURTHER INFORMATION CONTACT: DeWitt Burdeaux by phone at 405-954-7220 or by e-mail at dewitt.burdeaux@dot.gov.

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 "furthestmost 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, NAPSRS opposed the unqualified use of API RP 80 because of its use of the term "furthestmost downstream" to identify the beginning and possible ends of gathering. NAPSRS suggested several limitations to prevent manipulating the term "furthestmost 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, NAPSRS'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 NAPSRS contended, the "furthest 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 NAPSRS'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 NAPS'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 furthestmost 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 furthestmost 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 furthestmost 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 furthestmost 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 furthestmost 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 furthestmost downstream endpoint under sections 2.2(a)(1)(A) through (D), or in the absence of such an endpoint, the furthestmost 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 "furthestmost 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 "furthestmost 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 Furthestmost Point of Production

Under section 2.2(a)(1) of API RP 80, gathering begins at the furthestmost 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 furthestmost 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 furthestmost downstream point in a production operation. This furthestmost 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 Furthestmost Gas Processing Plant Endpoint

Under section 2.2(a)(1)(A) of API RP 80, gathering ends at the inlet of the furthestmost 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