Gas Regulatory Reform Rule

Gas Pipeline Advisory Committee
RIN: 2137-AF36
Docket: PHMSA–2018-0046

October 7, 2020

Outline

Introduction and Background

Vote 1: Topic A. Farm taps (§§ 192.740, 192.1003)

Vote 2: Topic B. Pressure vessel test requirements (§ 192.153)

Vote 3: Topic C. Incident report criteria (§ 191.3)

Vote 4:

- Topic D. Master Meter (§§ 192.1003, 192.1015)
- Topic E. Mechanical Fitting Failure Reporting (§§ 191.12, 192.1009)
- Topic F. Plastic Pipe (§§ 192.7, 192.123, 192.191, 192.283 Appendix B)

Outline

Vote 4:

- Topic D. Master Meter (§§ 192.1003, 192.1015)
- Topic E. Mechanical Fitting Failure Reporting (§§ 191.12, 192.1009)
- Topic F. Plastic Pipe (§§ 192.7, 192.123, 192.191, 192.283 Appendix B)

Vote 5:

- Topic G. Rectifier remote monitoring (§ 192.465)
- Topic H. Atmospheric corrosion (§ 192.481)

Vote 6:

- Topic I. Welder requalification (§ 192.229)
- Topic J. Pre-testing short segments & fabricated assemblies (§ 192.229)

Committee Report

Rule Background: Executive Orders

- **E.O. 13,771** “Reducing Regulation and Controlling Regulatory Costs”
  - Established expectation of two deregulatory actions for each significant regulatory action.
  - Sets departmental regulatory cost-budgeting scheme.
- **E.O. 13,777** “Enforcing the Regulatory Reform Agenda”
  - Requires agencies establish a Regulatory Reform Task Force and identify potential deregulatory actions.
- **E.O. 13,783** “Promoting Energy Independence and Economic Growth”
  - Requires agencies identify burdens on energy resources.

Rule Background: Departmental and PHMSA Actions

- DOT Transportation Infrastructure Notice: 82 FR 26734; 6/8/2017
  - Solicited comments on regulations that pose obstacles for transportation infrastructure
  - The DOT received 200 comments, including 6 relevant to the pipeline safety regulations
- DOT Notice of Regulatory Reform: 82 FR 45750; 10/2/2017
  - Requested comment on rules and other actions eligible for repeal, replacement, suspension, or modification without compromising safety
  - DOT received over 3,000 public comments, approximately 30 relevant to the pipeline safety regulations
- The Office of Pipeline Safety performed its own retrospective review of existing regulations and petitions from stakeholders.

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Rule Background: Departmental and PHMSA Actions

- PHMSA published a Notice of Proposed Rulemaking (NPRM) on June 9, 2020 (85 FR 35240; 6/9/2020)
  - The NPRM proposed regulatory amendments for 10 topics
  - Proposed regulatory amendments were drawn from:
    - Executive Orders
    - Regulatory reform docket comments
    - Infrastructure docket comments
    - Petitions for rulemaking
    - PHMSA staff review
  - PHMSA estimated that the 10 proposed amendments would result in $129 million in annualized cost savings for industry
- PHMSA proposed a parallel NPRM for hazardous liquid issues. Those topics, including part 190 amendments that affect gas pipeline operators, will be considered in a separate meeting.

Estimated Cost Savings ($millions, 7% discount rate)

Provision	Annualized Cost Savings
Farm Taps	**$67 million**
Master Meter Systems	$0.4 million
Mechanical Fitting Failure Reporting	$0.9 million
Incident Definition	$0.03 million
External Corrosion Control Monitoring	Minimal
Atmospheric Corrosion Monitoring	**$61 million**
Plastic Pipe	Not quantified
Test factor for Pressure Vessels	Not quantified
Welding Process requirement	Not quantified
Pre-testing fabricated assemblies and short segments of pipe	Not quantified
Total	**$129 million**

Estimated Cost Savings: Farm Taps

Farm taps **operated by distribution operators:** Based on comments from the AGA, PHMSA estimated:

- Approximately 81,000 farm taps are operated by local distribution companies
- Net cost savings of $1,546 every three years
  - $1,625 for each § 192.740 inspection (Once every three years), minus
  - $79 per farm tap to include it in a DIMP over three years.
- <u>Annual cost savings of 42 million</u>
  (81,071 farm taps × $1,546 every 3 year period ÷ 3 years)

Farm taps **operated by unregulated gathering and production lines:** Based on comments from IPAA and other production and gathering organizations, PHMSA estimated:

- Approximately 75,000 farm taps connected to unregulated source lines
- Average § 192.740 inspection costs of $1,013 every three years
- <u>Annual cost savings of $25 million</u>
  (75,000 farm taps × $1,013 every 3 year period ÷ 3 years)

PHMSA anticipates that operators of farm taps **connected to regulated gathering and transmission pipelines** will continue to comply with § 192.740 and therefore will not experience cost savings.

Total: $67 million per year.

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Estimated Cost Savings: Atmospheric Corrosion Monitoring: See Appendix C

Cost savings from reduced inspection frequency: <u>$34 million in year 1 and increases over time.</u>

- Cost savings represent the difference between the cost to perform atmospheric corrosion inspections on service lines with remotely read meters every 5 years vs every 3 years.
- Service lines with manually read meters are visited routinely by operator personnel and therefore do not result in cost savings.
- Based on annual reports, PHMSA estimated approximately 68 million service lines in year 1, and increases by 0.57% each year.
- Based on industry comments, PHMSA estimates that approximately 47% of service lines include remote meter reading technology and that the share of remotely read meters will increase over the assessment period. In year 1 PHMSA estimates 32 million remote meters.
- PHMSA estimated that an atmospheric corrosion inspection takes 0.2 hours with a $40.13 hourly cost of labor, assuming that a meter reader can inspect 5 service lines in an hour on average.

Cost savings from coordinating inspections: <u>$9 million in year 1 and increases over time.</u>

- Cost savings represent the cost difference between performing an AC survey on its own compared with the cost to add an AC survey to a leakage survey, multiplied by the number of AC surveys each year on a 5-year interval.
- APGA commented that adding an AC inspection to a leakage survey is approximately $4.50 each, excluding overhead labor costs.
- PHMSA estimated a cost savings of $0.984 per inspection, including overhead.

Total Annualized Cost Savings: $61 million

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Estimated Cost Savings: Other Provisions

Master Meter Systems: $480,000 per year (See table 11 of the RIA)

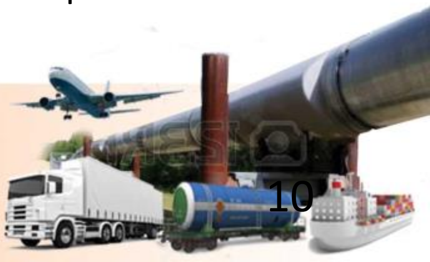
- PHMSA estimates an average hourly cost for IM personnel of $89.87 per hour (wages and benefits).
- New master meter operators (MMO) save 22 hours upfront from avoided IM plan preparation and threat identification burdens.
- Both new and existing MMOs save 4 hours every 5 years from avoided plan update costs.
- PHMSA determined that there are 5,461 existing MMOs, 30 new MMOs each year, and 30 MMOs exit the market each year.

MFF Forms: $940,000 per year (13,073 MFFs per year × 0.95 hrs. net burden reduction × $75.77/hr.)

- Average of 13,073 MFF reports per year
- An MFF report takes approximately 1 hour. PHMSA estimated that providing the total number of MFFs on a distribution annual report would by 5% as burdensome, resulting in a net burden reduction of 0.95 hours per report.
- PHMSA estimated an average labor cost of $75.77 per hour.

Incident Definition: $30,000 per year (40.1 fewer incident reports × 10 hours per report × $75.77/hr.)

- Based on incident reports between 2010 and 2018, PHMSA estimated that approximately 40.1 incidents per year resulted in property damage between $50,000 and $122,000 and did not result in other reportable consequences. These would not be reportable under the proposed rule.
  - 26.4 distribution incidents, 13.1 gas transmission and storage incidents, 0.1 LNG incidents per year.
- Each incident report takes 10 hours to prepare, with an average labor cost of $75.77 per hour.



NPRM Comment Summary

PHMSA received 43 comment submissions for the NPRM from a diverse group of stakeholders :

- Industry/Operator: TC Energy, Oleksa and Associates, Sander Resources, AmeriGas Propane, Superior Plus Propane, Southwest Gas, Norton McMurray, Theresa Pugh Consulting
- Industry Trades: AGA, API, APGA, INGAA, (the Associations) GPA Midstream Association, Independent Petroleum Association of America, Pennsylvania Independent Oil & Gas Association, Ohio Oil & Gas Association, National Propane Gas Association, Plastics Pipe Institute
- Government: NTSB, NAPSR
- Public Advocacy Groups: Pipeline Safety Trust, FreedomWorks Foundation
- Other Commenters: Citizen comments

General Comments

- The majority of pipeline industry commenters generally supported the proposed regulatory changes, agreed that pipeline safety would not be reduced, and recognized that a cost savings would result. Specific comments or requested modifications are addressed individually in this meeting.
- Multiple public commenters opposed any reduction in regulatory requirements. One commenter requests maintaining the current level of safety standards and another recommends that the pipeline industry reduce pipeline mileage and move toward renewable energy.

PHMSA Response:

- PHMSA appreciates the comments received in response to the NPRM topics. The proposed amendments have been determined to maintain the current level of safety standards.

General Comments

- Multiple commenters supported updates to IBR standards to incorporate more recent revisions. GPA Midstream requested that PHMSA enhance the IBR process to review updated versions of documents already IBR and either adopt the latest edition or provide an explanation for not adopting the document within one year of publication.

PHMSA Response:

- PHMSA will consider these comments and recommendations for future rulemaking actions. PHMSA reviews and, if appropriate, updates standards incorporated by reference periodically. Additional standards not referenced in the NPRM are being considered for updates in separate actions.

General Comments

- The PST commented on the general methodology used for the PRIA, questioning that industry burden is identified as negative costs rather than benefits as well as lacking explicit quantified benefit from the proposed rule elimination or revision. Benefits are presented as “no expected degradation of safety”.
- PST also reminds PHMSA that they believe a cost/benefit test is not appropriate in the context of regulations related to human health and safety, nor an appropriate way to decide whether the regulations should be altered.
- One industry SME requested modification to the PRIA analysis and methodology to account for secondary effects on customers for unplanned, emergency outages.

General Comments

PHMSA Response:

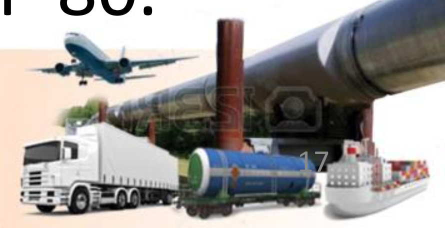
- The Office of Management and Budget (OMB) directs federal agencies to account for economic impacts to a regulated community on the cost-side of the ledger. Therefore, cost-savings to an operator are appropriately treated as negative costs in the RIA (OMB M-17-21; April 5, 2017).
- PHMSA has considered the safety impacts of the proposed rule based on available research and information to ensure that the proposed amendments would not reduce pipeline safety.
- The Pipeline Safety Act, E.O. 12,866, and OMB guidance require PHMSA consider the costs and benefits of pipeline safety standards.
- PHMSA is performing research on the costs that pipeline failures impose on downstream customers, however PHMSA does not anticipate the proposed rule will be adversely impact the reliability of the gas pipeline transportation system.

Topics for Discussion

A. Farm Taps (§§ 192.740, 192.1003)

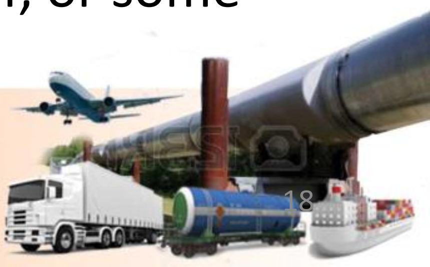
A. Farm Taps (§§ 192.740, 192.1003)
What is a Farm Tap?

- The term **Farm Tap** is not a regulatory classification in part 191 or part 192
- The term colloquially refers to a pipeline providing gas service to customers along a transmission, gathering, or production pipeline rather than from a distribution system.
- Delivering natural gas to a residential or commercial customer is not a production or gathering function under 192.3 or API RP 80.



A. Farm Taps (§§ 192.740, 192.1003) **Background**

- Characteristics of Farm Taps.
  - Operators often agree to provide gas service to landowners along a pipeline in exchange for right-of-way agreements.
  - Farm taps are typically, but not always, in Class 1 locations.
  - Significant portions of a farm tap may be owned and maintained by the customer.
- Farm taps have unique safety considerations.
  - Unlike a typical distribution system, the source pipeline may operate at high pressures and is typically not odorized.
  - By definition the source pipeline is not typically operated by a local distribution company.
  - The “farm tap” itself may be operated by the source pipeline operator, a local distribution company, the customer, or some combination of those entities.



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A. Farm Taps (§§ 192.740, 192.1003)
Background

- The **2015 Miscellaneous Rule** attempted to eliminate duplicative integrity management requirements while addressing over pressurization risks. The rule:
  – Exempted individual service lines directly connected to production, gathering, and transmission pipelines (i.e. farm taps) from DIMP.
  – Required operators inspect pressure regulating devices on farm tap service lines once every 3 years.
- Some farm taps are owned or operated by local distribution companies.
  – Distribution operators favored applying their existing DIMP to implementing the new inspection requirements.
  – Some transmission and gathering operators preferred a prescriptive inspection requirement to establishing a DIMP.

A. Farm Taps (§§ 192.740, 192.1003) **Background**

PHMSA has initiated the following projects with regard to farm taps:

- Exercise of Enforcement Discretion Regarding Farm Taps, March 26, 2019 (84 FR 11253)
  - PHMSA indicated it would not pursue enforcement of § 192.740 for farm taps included under a DIMP.
  - This policy would be codified by the proposed rule.
- Proposed Farm Taps FAQs, April 20, 2020 (85 FR 21820)
  - 20 FAQs on the applicability of parts 191 and 192 with respect to farm taps.
  - PHMSA will publish updated guidance on the agency website.

A. Farm Taps (§§ 192.740, 192.1003)
Proposal

The NPRM proposed the following:

- A service line directly connected to a regulated gathering line or a transmission line that is included in a DIMP is exempt from § 192.740 (codifies enforcement discretion).
- A farm tap service line that is not included in a DIMP must continue to be inspected per § 192.740.
- Service lines directly connected to non-regulated gathering or production source pipelines are exempt from § 192.740, DIMP and annual reporting.

A. Farm Taps (§§ 192.740, 192.1003
Affected Infrastructure

- PHMSA estimated the NPRM would affect ~150,000 farm taps divided between:
  - Farm taps operated by local distribution companies
  - Farm taps connected to unregulated gathering and production pipelines
- PHMSA assumes farm taps operated by transmission or regulated gathering operators will continue to comply with the existing § 192.740 inspection requirement and therefore not be affected.

A. Farm Taps (§§ 192.740, 192.1003) **Comments**

- Some gas gathering operators and producers commented that the part 192 requirements for distribution pipelines do not apply to farm taps connected to production pipelines and rural gathering lines and requested explicit regulatory exceptions/exclusions to all or portions of Parts 191 and 192 for farm taps extending from unregulated lines.
- IOGAWV commented that even as revised, PHMSA’s proposed farm tap rules are not justified. A producer or unregulated gathering line operator with one qualifying farm tap could be subject to hundreds of regulations otherwise not applicable to its business.
- The IPAA noted that many “farm taps” and related facilities are a result of state statutes and regulations which govern contractual agreements between producers and landowners or other parties. Imposing regulations on those farm taps interferes with the parties’ established contractual or state statutory relations.

A. Farm Taps (§§ 192.740, 192.1003) **Comments**

PHMSA Response:

- Regulation of service lines in farm tap configurations is not a new feature of the NPRM or the 2015 Miscellaneous Rule (80 FR 12762).
- The modern definition for the endpoint of a service line was finalized on April 10, 1973. Regulation of farm taps and other delivery lines where a meter is not present was an explicit goal of the May 27, 1971 NPRM for that action.
- PHMSA and its predecessor agencies have been consistent in subsequent regulations, guidance, and interpretations that portions of a “farm tap” that provides gas service to residential and small commercial customers is performing a distribution function.
- Excluding service lines connected to unregulated gathering and production lines from the scope of parts 191 and 192 would be a consequential change outside the scope of the NPRM.

A. Farm Taps (§§ 192.740, 192.1003)
Comments

- The IPAA and supporting organizations commented that the prior discussions of farm taps have not fully addressed issues related to definitions, terminology and clear requirements for farm taps.
- IPAA and IOGAWV requests that PHMSA explicitly exclude farm taps originating from nonregulated lines in the definition of service line or clarify in the FAQs on Docket PHMSA-2019-0131 that that customer-owned lines and equipment are not jurisdictional.

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A. Farm Taps (§§ 192.740, 192.1003) **Comments**

PHMSA Response:

- The intent of the rule is solely to address the applicability of §192.740 and DIMP requirements for farm taps rather than to resolve broader definitional issues associated with farm tap service lines.
- PHMSA will consider these comments and respond fully to the issue of operator responsibility for customer-owned service lines via the proposed Farm Tap FAQs.
- Excluding service lines connected to unregulated gathering and production lines from the scope of parts 191 and 192 would be a consequential change outside the scope of the NPRM.

A. Farm Taps (§§ 192.740, 192.1003) **Comments**

- The Associations generally supported the amendment but opposed definition of the start of a service line implied in paragraph (c)(4).
- The Associations and others requested that operators be allowed to voluntarily classify farm tap or service line piping in the same manner as the regulated source pipeline (regulated gathering or transmission), even if it could be classified as distribution. All applicable regulations would apply based on the classification.
- TC Energy suggested revisions to §192.740 in lieu of defining where service lines start for farm taps that would instead apply the requirements to "any pipeline, other than one that is operated as part of a gas distribution system that delivers gas to a farm tap customer." [cont.]

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A. Farm Taps (§§ 192.740, 192.1003)
Comments

- Industry commenters requested that PHMSA update or create definitions for “transmission line,” “service line,” “farm taps,” and “distribution center.”
- Industry comments suggested PHMSA allow operators to establish variable start points for service lines reflecting the variability of equipment configurations, ownership changes, operating pressures.
- Industry commenters suggested PHMSA recognize that an operator can deliver to a customer directly from a production, gathering, or transmission line without first passing through a service line.

A. Farm Taps (§§ 192.740, 192.1003) **Comments**

PHMSA Response:

This rulemaking is intended only to address the applicability of §192.740 and DIMP requirements:

- PHMSA will remove paragraph (c)(4), thus eliminating language implying when a service line begins.
- Definitional issues will be addressed to the extent possible by the proposed Farm Tap FAQs (PHMSA-2019-0131)
- Certain aspects of the transmission line definition raised by commenters are being considered as part of Gas Transmission and Gas Gathering NPRM (81 FR 20721) proceedings.
- Future rulemaking may be considered if necessary to address remaining definition-related issues.

A. Farm Taps (§§ 192.740, 192.1003) **PHMSA Recommendation**

This concludes the PHMSA response to comments on the Farm Tap topic.

In light of comments received from the NPRM, PHMSA recommends the Committee consider adopting the proposal with the following changes:

- Remove paragraph 192.740(c)(4), thus eliminating language implying when a service line begins.

A. Farm Taps (§§ 192.740, 192.1003)

Public Comments

A. Farm Taps (§§ 192.740, 192.1003)

GPAC Discussion

A. Farm Taps (§§ 192.740, 192.1003)

Committee Voting Slides

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to farm taps are technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Remove paragraph 192.740(c)(4).

Topics for Discussion

B. Pressure Vessel Tests (§ 192.153(e))

B. Pressure Vessel Tests (§ 192.153(e)) **Background**

- Pressure vessels are commonly used in metering stations, compressor stations, and other facilities to remove liquids and other materials from the gas stream.
- § 192.505(b) requires testing compressor station, regulator station, and measuring stations to Class 3 test requirements (i.e. a test factor of 1.5 times MAOP).
- § 192.153(b) requires pressure vessels be designed, constructed, and tested in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code (BPVC)

B. Pressure Vessel Tests (§ 192.153(e))
Background

- The 1998 and prior editions of ASME BPVC Section VIII Division 1 required pressure vessels be subjected to a test pressure of at least 1.5 times the maximum allowable working pressure (MAWP) (UG-99(b)).
- The 2001 and subsequent editions of the ASME BPVC revised this requirement to 1.3 times the MAWP.
- PHMSA incorporated by reference the 2001 edition of the ASME BPVC effective July 14, 2004.
- However, PHMSA did not make corresponding changes to the test factor in § 192.505(b).

B. Pressure Vessel Tests (§ 192.153(e)) **Background**

- Commenters claimed the structure of part 192 and the conflict between the ASME BPVC and part 192 test requirements has led to confusion.
- Some operators have been testing vessels to 1.3 times the MAWP as specified in the ASME BPVC since July 14, 2004, the effective date of the incorporation by reference of the 2001 edition of the ASME BPVC.
- Industry groups have argued that § 192.505(b) does not apply to pressure vessels and other non-tubing components within compressor stations.

B. Pressure Vessel Tests (§ 192.153(e)) **Background**

- Re-testing or replacing large numbers of otherwise safe vessels to comply with § 192.505(b) could result in operational disruptions, worker safety hazards, and significant costs.
- Commenters argued that PHMSA should accept a manufacturer pressure test of ASME vessels rather than requiring a post-installation, subpart J test.
- The ASME BPVC is accepted by many Federal agencies.
  – Adopted by the Occupational Safety and Health Administration, the Bureau of Safety and Environmental Enforcement, the Department of Energy, and the Department of Defense.
  – The Chemical Safety Board noted it is an internationally recognized good practice (CSB No. 2005-02-I-TX, section 4.4.1).

B. Pressure Vessel Tests (§ 192.153(e)) **Background**

- PHMSA commissioned a report from the Oak Ridge National Laboratory (ORNL) to evaluate the ASME BPVC in 2017.
  - ORNL report determined safety equivalency between 1992 and 2015 editions of the ASME BPVC. The 1992 edition includes a 1.5 test factor while the 2015 edition includes the revised 1.3 test factor.
  - ORNL findings included an independent determination that a 1.3 test factor provided an equivalent level of safety compared with a 1.5 test factor.
- The report evaluated pressure testing requirements in addition to the below requirements:
  - materials;
  - design including failure modes,
  - strength theories, and
  - principles of limit design theory; fabrication and inspection including nondestructive examinations; and overpressure protection.

B. Pressure Vessel Tests (§ 192.153(e)) **Background**

The ORNL report made the following conclusions with regard to the test factor requirements.

- "Hydrostatic pressure testing limits in the 2015 edition provide equivalent safety to hydrostatic pressure testing limits in the 1992 edition"
- Pressure tests in the ASME BPVC are primarily intended to verify the leak tight integrity of the pressure vessel and are not intended to serve as a burst test of the vessel.
- Overpressure protection requirements in both the 1992 and 2015 editions of ASME BPVC section VIII and § 192.201 (max of 1.1 times MAOP) ensure that a vessel will never experience an in-service overpressure greater than 1.3 times MAOP in service. PHMSA notes that these requirements have not changed between the 2001 edition and the 2015 edition evaluated by ORNL.

B. Pressure Vessel Tests (§ 192.153(e)) **Proposed Rule**

- PHMSA proposed to allow operators to continue to operate vessels installed after 2004 but **before the effective date** of the final rule that were tested to 1.3 times the MAOP in addition to the BPVC requirements. These vessels would no longer need to be retested.
- For vessels installed **after the effective date** of the final rule, PHMSA proposed to:
  - Allow 1.3 test factor in addition to BPVC requirements,
  - Clarify that subpart J test duration requirements apply, and
  - For newly-manufactured vessels, allow an operator to use a strength test performed by the manufacturer if the operator inspects and remediates any damage to the vessel in accordance with the BPVC after it is transported to the installation location.

B. Pressure Vessel Tests (§ 192.153(e)) **Comments**

- PST believes that PHMSA is prevented from making changes proposed in §192.153(e) for any pressure vessel that is installed in a pipeline facility prior to the effective date of the rule.

PHMSA Response:

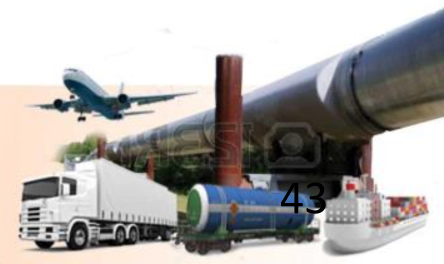
- PHMSA does not view the nonapplication clause as applicable here – The rulemaking will not force any operator to take an action to re-design or construct an existing facility.
- This section is also a response to a Petition for Reconsideration of the Miscellaneous Rule – PHMSA must be able to address challenges to design standards in rulemaking actions.
- Requiring operators to remove pressure vessels that otherwise comply with part 192 and the ASME BPVC and have been operating safely would expose operator employees to unnecessary safety hazards associated with moving and pressure testing large pressure vessels, disrupt pipeline operations, and incur significant costs.
- The change is intended to resolve this issue while minimizing safety, operational, and economic consequences and is consistent with recognized engineering standards.

B. Pressure Vessel Tests (§ 192.153(e)) **Comments**

- PST requests additional technical support to justify the applying a 2015 edition to any vessel designed and fabricated under a prior edition of the standard. The Oak Ridge study does not disclose all changes between the 2001 and 2015 editions, and therefore do not fully support PHMSA's stance that an equivalent level of safety is provided.

PHMSA Response:

- The ORNL report separately determined that hydrostatic pressure testing limits in the 2015 edition provide equivalent safety to hydrostatic pressure testing limits in the 1992 edition (Table 9.2 and section 7.1.2.1). [Continued]



B. Pressure Vessel Tests (§ 192.153(e)) **Comments**

PHMSA Response:

- The report further determines that the overpressure protection requirements ensure that a vessel will not be operated at a pressure exceeding 1.3 times the MAWP in service. The required overpressure protection limits in § 192.201 and the ASME BPVC, including in intermediate editions that have been incorporated by reference into the pipeline safety code in the past, have not changed since the 2001 edition was adopted.
- The ASME BPVC does not specify minimum test durations. Clarifying that test duration requirements apply to new and replaced pressure vessels in the future could result in an increased level of safety depending on the rate of baseline compliance.
- The ASME BPVC is an internationally recognized good practice adopted by several other Federal Government agencies.

B. Pressure Vessel Tests (§ 192.153(e)) **Comments**

- The Associations and National Fuel Gas Company requested that PHMSA remove the requirement to test pressure vessels "in place." They commented that some configurations make testing impractical or unsafe due to facility activity or installation location.

PHMSA Response:

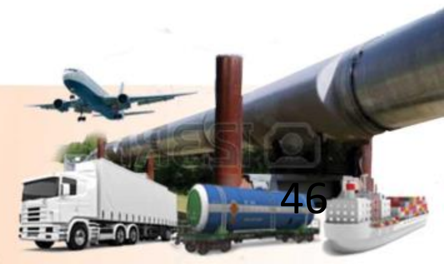
- PHMSA acknowledges that while testing vessels after tie-in complicates the testing and inspection process, these same challenges create risks of damaging the pressure vessel during movement and installation within a pipeline facility.
- PHMSA will clarify that testing or inspection is expected to take place after the vessel has been put on its supports at the intended installation location, but may occur prior to tie-in with station piping.

B. Pressure Vessel Tests (§ 192.153(e))
Comments

- The Associations supported aligning regulations with the ASME BPVC test requirements, especially in the option to visually inspect rather than re-testing.
- Associations also request that visual inspection or retesting apply to all pressure vessel relocations after the effective date, rather than just "newly manufactured" vessels.

PHMSA Response:

- The inspection is typically a visual inspection, however an operator's procedure or a qualified inspector may require other inspection methods based upon damage.
- PHMSA did not propose to allow the use of a manufacturer's test for relocated, existing vessels. [Continued]



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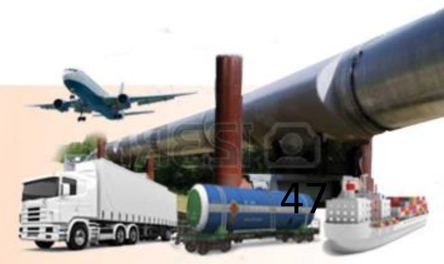
B. Pressure Vessel Tests (§ 192.153(e))
Comments

PHMSA Response:

- A technical article published by the National Board of Boiler and Pressure Vessel Inspectors acknowledges jurisdictional requirements for relocations may apply and notes that safety considerations for relocations and other changes require careful consideration and analysis.
- PHMSA will consider adding regulatory language clarifying the following requirements for relocating existing vessels:
  - The operator must have documentation that the relocated vessel meets current design and construction requirements and be re-tested by the operator in accordance with existing § 192.503(a).
  - The operator must inspect the vessel after installation but prior to tie-in to ensure that there are no injurious defects such as corrosion or cracking.



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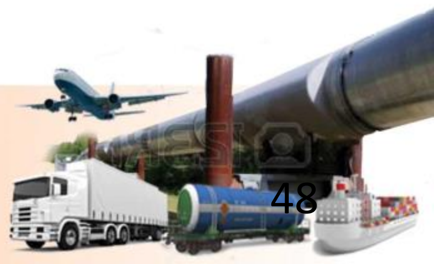
B. Pressure Vessel Tests (§ 192.153(e))

This concludes the PHMSA response to comments on Pressure Vessel Test Requirements.

In light of comments received from the NPRM, PHMSA recommends the Committee consider adopting the proposal with the following changes:

- Clarifying that testing or inspection is expected to take place after a vessel is placed on its supports at its installation location, but may occur prior to tie-in with station piping.
- Clarifying that relocated vessels must meet current design and construction requirements, be retested by the operator, and be inspected after installation, but prior to tie-in, to ensure there are no injurious defects.



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B. Pressure Vessel Tests (§ 192.153(e))

Public Comments

B. Pressure Vessel Tests (§ 192.153(e))

GPAC Discussion

B. Pressure Vessel Tests (§ 192.153(e))

Committee Voting Slides

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to testing requirements for pressure vessels, are technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Clarify that testing or inspection is expected to take place after being placed on its supports at its installation location, but may occur prior to tie-in with station piping.
- Clarify that relocated vessels must meet current design and construction requirements, be retested by the operator, and be inspected after installation, but prior to tie-in, to ensure there are no injurious defects.

Topics for Discussion

C. Incident Report Criteria (§ 191.3)

C. Incident Report Criteria (§ 191.3)

Background

- An incident is defined in § 191.3 as an event that meets any of the following criteria:
  - A death or injury necessitating in-patient hospitalization,
  - **Property damage of $50,000 or more, including loss to the operator, but excluding the cost of loss gas,**
  - An unintentional gas loss of over 3 million cubic feet, or
  - Emergency shutdown of a liquefied natural gas facility or underground natural gas storage facility.
- The property damage criterion has not been adjusted since 1984; as a result the criterion results in less consequential incidents being reported over time due to inflation.
- This issue was raised in comments on DOT's notice of regulatory reform.

C. Incident Report Criteria (§ 191.3)
Proposed Rule

PHMSA proposed the following amendments:

- Raise the property damage criterion to $122,000 consistent with CPI inflation since 1984.
- The other criteria remain unchanged.
- PHMSA estimates the proposed rule would reduce the number of reportable incidents by 18%.
- PHMSA also sought comments on:
  - Procedures for automatic or administrative updates to the criteria in the future similar to those proposed by the Federal Railroad Administration (49 CFR 225.19 and Appendix B to part 225.
  - An appropriate method and frequency of future updates.

C. Incident Report Criteria (§ 191.3)

Comments

- The Associations and other industry commenters supported adjusting the property damage threshold for inflation based on the effective date of the rule and biennially thereafter.
- TC Energy recommended a threshold of $250,000 was more appropriate. They noted that $122,000 would still encompass most minor incidents that are captured at $50,000 based on current costs for labor, repairs materials, permits, etc.
- FreedomWorks Foundation supported removing the property damage threshold from the definition of incident.

[Continued]

C. Incident Report Criteria (§ 191.3)
Comments

PHMSA Response:

- PHMSA continues to support the proposal to update the $50,000 property damage threshold based on inflation.
- PHMSA will ensure that the value adopted in the final rule is consistent with inflation as of the year of publication.
- PHMSA agrees that regular updates are appropriate and will consider procedures similar to those proposed by the Federal Railroad Administration (proposed in FRA-2014-0099):
  - A formula is adopted into Appendix B to part 255.
  - FRA would announce regular updates based on this formula on their website.
- PHMSA does not believe an arbitrarily higher damage threshold or eliminating the damage threshold as a criterion are appropriate.

C. Incident Report Criteria (§ 191.3)

Comments

- PST opposed increasing the property damage threshold, particularly when it results in collecting additional data for known issues.
- PST opposed frequent, incremental changes to the incident definition, commenting that it would affect the ability to compare trends over time. PST instead recommend a comprehensive review of the definition of an incident if the current definition is not meeting PHMSA’s needs.
- NAPSR suggested that PHMSA first study the effects that changing the reportable criteria dollar amount would have on providing information for state programs, the public, and PHMSA analyses associated with rulemaking actions.

[cont.]

C. Incident Report Criteria (§ 191.3)
Comments

PHMSA Response:

- Inflation adjustment ensures the consistency of reporting trends. A static property damage criterion changes over time in inflation adjusted terms.
- PHMSA's analyses of trends already account for inflation. The significant incident trend analysis filters out incidents that don't meet the other criteria and result in less than $50,000 in 1984 dollars. A full description can be found at this address: https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-20-year-trends.
- PHMSA will consider changes to the significant incident definition based on the final rule to ensure consistent long-term trending of significant incidents.

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C. Incident Report Criteria (§ 191.3)

This concludes the PHMSA response to comments on Incident Report Criteria.

In light of comments received from the NPRM, PHMSA recommends the Committee adopting the proposal with the following changes:

- Adopt an appropriate inflation adjustment based on the CPI at the date of final rule publication.
- Incorporate a formula in part 191 for future updates similar to the proposed FRA procedures (FRA-2014-0099).

C. Incident Report Criteria (§ 191.3)

Public Comments

C. Incident Report Criteria (§ 191.3)

GPAC Discussion

C. Incident Report Criteria (§ 191.3)

Committee Voting Slides

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to the property damage threshold for reporting incidents, are technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Adopt an appropriate inflation adjustment based on the CPI at the date of final rule publication.
- Incorporate a formula in part 191 for future updates similar to the proposed FRA procedures.

Topics for Discussion

D. Master Meters (§§ 192.1003, 192.1015)
E. Mechanical Fitting Failure (MFF) Reports (§§ 191.12, 192.1009)
F. Plastic Pipe (§§ 192.7, 192.123, 192.191, 192.283, Appendix B)

D. Master Meters (§§ 192.1003, 192.1015): **Background**

- A master meter is defined in part 191 as a distribution system that purchases metered gas from a local distribution company for resale within a defined area.
  - Ex: apartment complex, trailer park, etc.
- There are tens of thousands in existence.
- A typical master meter system is less than a mile in length, and serves fewer than 300 customers, and operates at a low operating pressure vs typical distribution system.

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D. Master Meters (§§ 192.1003, 192.1015)
Background

- Master meter systems must currently comply with the following simplified DIMP requirements specified in § 192.1015:
  - Have knowledge of their system,
  - Identify threats,
  - Rank risks,
  - Identify and implement measures to mitigate risks,
  - Measure performance, monitor results, and evaluate effectiveness,
  - Periodically evaluate and improve the program.
- Many master meter systems rely on a third-party computer program to generate a DIMP.

D. Master Meters (§§ 192.1003, 192.1015) **Background**

- DIMP has had a low safety impact for master meter systems.
  - Inspection reports indicate effective implementation and compliance with DIMP has been a challenge despite inspector focus.
  - Most master meter systems are small, simple systems that don’t require a risk-management regime to protect adequately
- Therefore, DIMP requirements for master meter systems place an unnecessary burden on operators and inspectors.
  - The number of master meter systems and implementation problems creates a significant DIMP inspection workload for State inspectors.
  - The requirements draw operator’s efforts towards risk management requirements they neither need nor understand.
- Focusing operator and inspector efforts on compliance with basic prescriptive requirements is likely to have a greater impact on safety with less burden. These include:
  - Operations and maintenance procedures, in subparts L and M including abnormal operating procedures;
  - Continuing surveillance requirements in § 192.613;
  - Failure investigation requirements § 192.617.

D. Master Meters (§§ 192.1003, 192.1015) **Proposed Rule**

- PHMSA proposed to exempt master meter systems from DIMP.
- PHMSA also sought comment on if it was appropriate to extend incident reporting requirements to master meter systems.

D. Master Meters (§§ 192.1003, 192.1015) **Comments**

- The National Propane Gas Association and many others commented in support of master meter exclusions. They further stated that small liquefied petroleum gas (LPG) operators should be subject to the same exclusions.
  - Note: A small LPG system is defined in § 192.1001 as a gas distribution system that serves fewer than 100 customers from a single source of LPG (typically a propane tank).
- NAPSR commented in favor of the exclusions, and also requested to exclude small LPG systems and other small distribution operators with fewer than 100 customers.
- PST did not oppose DIMP exemptions for master meters provided that other minimum safety standards continue to apply and are effectively enforced.

D. Master Meters (§§ 192.1003, 192.1015) **Comments**

PHMSA Response:

- The Transportation Research Board (TRB) published a study of the safety requirements applicable to small LPG systems in 2018.
  - The TRB recommended a PHMSA administered process for approving State waiver programs that would allow a state to exempt small LPG systems from specific requirements on a case-by-case basis rather than a general exception from DIMP or any other requirement.
  - TRB Special Report 327, “Safety Regulation for Small LPG Distribution Systems.” Available as a free download from https://www.nap.edu/catalog/25245/safety-regulation-for-small-lpg-distribution-systems.
- Based on the comments and the conclusions of the TRB study, PHMSA believes that this issue requires additional analysis and notice and comment procedures.
- PHMSA will consider these comments and the recommendations from the TRB study in a future rulemaking action.

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D. Master Meters (§§ 192.1003, 192.1015) **Comments**

- One industry SME commented to oppose extending incident reporting requirements to master meter systems and small LPG operators. The commenter suggested that the poor data quality from such operators would degrade the usefulness of the incident database.

PHMSA Response:

- PHMSA will evaluate if it is appropriate to apply incident reporting to master meter systems to ensure consistency in the Pipeline Safety Regulations in future rulemaking actions.
- PHMSA notes that existing § 191.9 does not except small LPG operators from incident report requirements.

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E. Mechanical Fitting Failure (MFF) Reports

E. MFF Reports: §§ 191.12,192.1009
Background

- Mechanical fittings are devices that join pieces of pipe using mechanical pressure rather than welding or heat fusion.
- These devices are common on distribution lines, especially service line connections.
- In 2011 PHMSA required operators report leaks caused by mechanical fitting failures (MFF) except those that are non-hazardous leaks.
- A leak is a much broader category compared to an incident since it is not limited by minimum consequence criteria.
- The MFF form includes basic cause and manufacturing information.

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E. MFF Reports: §§ 191.12,192.1009
Background

- PHMSA has not identified statistically significant trends in the MFF data.
- The Plastic Pipe final rule addresses failures caused by insufficient pullout restraint and inadequate resistance to anticipated loads.
- The low reporting criteria results in an average of approximately 15,000 reports per year.
- Attributes about mechanical joint failures are repeated in incident reports for more significant events.

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E. MFF Reports: §§ 191.12,192.1009
Proposed Rule

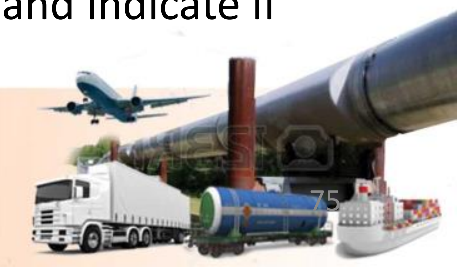
- PHMSA proposed to eliminate the MFF report and to reinstate cross-referenced information in the incident report form.
- PHMSA also proposed to add a count of leaks due to MFFs to the gas distribution annual report form. This allows PHMSA to continue measuring overall trends in mechanical joint performance over time and amongst operators.
- The proposed change eliminates approximately 12,000-18,000 reports per year and reduces the burden of providing MFF information by ~95%.
- The change has no safety impact. Keeping a count of leaks provides performance information that is valuable to PHMSA and State inspectors.

E. MFF Reports: §§ 191.12,192.1009 Comments

- The NPGA and many others generally support removing MFF reports.
- Dresser and NORMAC opposed adding MFF data to the distribution annual report since they are already captured under other categories of leaks.
- PST opposes removing MFF report requirements on the basis that data is valuable in identifying problems. Removing reporting requirements that are relatively low in cost and could potentially provide insight to future trends in safety as well as regulatory effectiveness is shortsighted.

PHMSA Response:

- PHMSA disagrees with changes proposed in the comments from the NPGA and industry, PST, and manufacturers.
  - Nine years of data collection of approximately 15,000 MFF reports each year have not provided statistically significant trends in failures of mechanical joints.
  - Conversely, gas distribution incidents result in approx. 100 reports annually for all causes combined.
  - A future combination of incident reports and a count of leaks on the gas distribution annual report will adequately meet PHMSA’s information needs and indicate if circumstances change in the future.



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E. MFF Reports: §§ 191.12,192.1009 Comments

- Dresser and NORMAC also provided requests to revise the incident report forms and instructions to clarify joint failure causes.
- NORMAC requested that PHSMA address the distinction between “mechanical fitting” and “joint” by changing terminology in the proposed rulemaking to ensure that its regulations and other actions focus on joints, the making of joints, and the qualifying of joining procedures.

PHMSA Response:

- Other changes to the incident and annual report form are outside the scope of this rule; however, PHMSA will consider the issues raised during future updates to forms and instructions via the normal Paperwork Reduction Act process.

F. Plastic Pipe

F. Plastic Pipe
(§§ 192.7, 192.123, 192.191, 192.283, Appendix B)
Background: Polyethylene Standards and Diameter Limit

- PHMSA published a final rule addressing a number of plastic pipe topics on 11/20/2018 (83 FR 58694).
  - The rule added allowed a design factor of 0.40 rather than 0.32 with certain conditions, including minimum wall thickness based on ASTM D2513, “Standard Specification for Polyethylene Gas Pressure Pipe, Tubing and Fittings” published by ASTM International. That edition did not include wall thickness specifications for sizes larger than 12 inches.
  - PHMSA indicated in preamble of that rule that it would evaluate newer editions of ASTM D2513 and consider allowing larger-diameter pipe with a 0.40 design factor in the future.
- PHMSA staff has reviewed ASTM D2513-18a and determined incorporating it by reference in part 192 is justified.
- ASTM D2513-18a includes minimum wall thickness specifications for sizes up to 24 inches and PHMSA has no technical issue with allowing a 0.40 design factor for those sizes.

F. Plastic Pipe
(§§ 192.7, 192.123, 192.191, 192.283, Appendix B)
Background: Joining Procedures

- ASTM F2620, "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings" describes procedures for making heat fusion joints.
- Section 192.281(c) requires heat fusion joints on PE pipe comply with ASTM F2620-12.
- Section 192.285(b)(2) allows visual inspection and testing in accordance with ASTM F2620-12 as an option for evaluating a polyethylene pipe joiner's test joint prepared for requalification.

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F. Plastic Pipe
(§§ 192.7, 192.123, 192.191, 192.283, Appendix B)
Background: Joining Procedures

- In the preamble of the Plastic Pipe Rule, PHMSA indicated that alternative procedures comparable to ASTM F2620 could be acceptable if the operator can demonstrate the differences are sound and provide an equivalent or better level of safety, however this is not clear in the regulatory text.
- AGA submitted a petition for reconsideration suggesting allowing other procedures qualified in accordance with § 192.283, including two standards developed by the Plastics Pipe Institute.
- Newer editions of ASTM F2620 include safety improvements and clarify how they relate to other industry documents, including those referenced by AGA.

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F. Plastic Pipe

(§§ 192.7, 192.123, 192.191, 192.283, Appendix B)

Proposed Rule

- **ASTM D2513** PHMSA proposed to:
  - Incorporate by reference the 2018a edition of ASTM D2513, and
  - Allow a 0.40 design factor for PE pipe with a diameter up to 24 inches outside diameter.
- **Joining Procedures** PHMSA proposed to:
  - Incorporate by reference the 2019 edition of ASTM F2620 – the newer document clarifies how the standard relates to other standard practices referenced in AGA's petition.
  - Clarify that written procedures that have been demonstrated to be equivalent to or superior to ASTM F2620 are permitted.


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F. Plastic Pipe

(§§ 192.7, 192.123, 192.191, 192.283, Appendix B)

Proposed Rule

Miscellaneous amendments and corrections

- § 192.121
  - Revise “design formula” to “design pressure”
  - Correct the minimum wall thickness for 1” CTS pipe
  - Clarify that pipe produced on the effective date of the plastic pipe final rule may use the revised design factor
- § 192.283(a)(3): Correct “no more than” to “no less than” and clarify that the test is a tensile test.
- § 192.285: Clarify that specimen PE heat-fusion joints inspected under § 192.285(b)(2)(i) must be visually inspected in accordance with F2620 and tested in accordance with § 192.283(a).

F. Plastic Pipe

(§§ 192.7, 192.123, 192.191, 192.283, Appendix B)

Comments

- The Associations and many other industry entities generally support the changes to plastic pipe regulations.
- PST responded with “no comment” on this item.
- Many industry commenters stated support of this item without additional comment.

PHMSA Response:

- PHMSA appreciates feedback on the proposed rule.

F. Plastic Pipe

(§§ 192.7, 192.123, 192.191, 192.283, Appendix B)

Comments

- The Associations commented that the proposed revision to table labeled “PE Pipe: Minimum Wall Thickness and SDR Values” (Table 1) of §192.121(c)(2)(iv) does not include SDR 11.5, 1” CTS pipe, which has a 0.099 wall thickness and is in common use. The Associations request that PHMSA include SDR 11.5 pipe in Table 1.
- NAPSR requested clarification on this issue as well.

PHMSA Response

- A 0.099 inch wall thickness most closely corresponds to SDR 11 for 1” CTS pipe, however PHMSA does not object to adopting a 0.099 inch wall thickness.
- PHMSA notes that the two specifications are within allowable tolerances of each other in the ASTM codes.

F. Plastic Pipe

(§§ 192.7, 192.123, 192.191, 192.283, Appendix B)

Comments

- Plastics Pipe Institute (PPI) supports the IBR of updated industry standards to ensure the latest materials, testing and innovations are recognized in 49 CFR part 192. The IBR of ASTM D2513-18a, while not the latest standard version, provides important updates related to UV protection and dimensions.
- PPI requests reference to specific example procedures PPI TR-33 and PPI TR-41 (however is not requesting IBR of those procedures).

PHMSA Response:

- PHMSA appreciates the feedback on the proposed rule.
- PHMSA cannot IBR documents that have not been subject to notice and comment. However, if an operator can demonstrate that their alternative procedure based on those documents provides an equivalent or superior level of safety compared with ASTM F2620, it would be acceptable under the proposed amendment.

F. Plastic Pipe
(§§ 192.7, 192.123, 192.191, 192.283, Appendix B)
Comments

- PPI strongly supports the change to increase allowable dimensions for polyethylene pipe up through 24 inches along with the corresponding wall thickness table.
- PPI also requests that PHMSA update §192.121(a) to allow hydrostatic design basis (HDB) ratings established at 180°F, which is allowable in the PPI TR-4, incorporated in the Plastic Pipe Rule, but not in § 192.121.

PHMSA Response:

- PHMSA proposed no changes to the design formula and this comment is out of scope, PHMSA will evaluate the issue for future rulemaking if appropriate.
- PHMSA notes that operators are permitted to interpolate the design formula down from 180°F but cautions that not all PE compounds are rated at that temperature.

D. Master Meter, E. MFF Report, and F. Plastic Pipe

This concludes the PHMSA response to comments on Master Meter, MFF Report, and Plastic Pipe topics.

In light of comments received from the NPRM, PHMSA recommends the Committee consider adopting the proposal with the following changes:

- Regarding master meters, no changes to the NPRM are recommended.
  - PHMSA will consider the comments received with regard to small LPG systems, the TRB report and propose appropriate revisions to the regulation of such systems in a future rulemaking action.
- Regarding the MFF amendments, no changes to the NPRM are recommended.
- Regarding Plastic pipe, modify the minimum wall thickness table for PE to specify a 0.099 inch minimum wall thickness for 1” CTS pipe rather than 0.101 inches.

D. Master Meter, E. MFF Report, and F. Plastic Pipe

Public Comments

D. Master Meter, E. MFF Report, and F. Plastic Pipe

GPAC Discussion

D. Master Meter, E. MFF Report, and F. Plastic Pipe

Committee Voting Slides

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to master meter applicability, mechanical fitting failure reports, and plastic pipe, are technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Regarding plastic pipe, revise the minimum wall thickness tables for plastic pipe to specify 0.099 inch minimum wall thickness for 1" CTS pipe rather than 0.101 inch.

Topics for Discussion

G. Rectifier Remote Monitoring (§ 192.465)

H. Atmospheric Corrosion (§ 192.481)

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G. Rectifier Remote Monitoring (§ 192.465) **Background**

- A rectifier impresses a direct current onto a pipeline, providing protection from corrosion.
- Rectifier stations must be inspected six times a year under § 192.465.
- It is not clear in the regulations that these inspections may be conducted remotely, however PHMSA has interpreted the requirement to be technology-neutral.
- The code does not specify what constitutes a rectifier inspection.

G. Rectifier Remote Monitoring (§ 192.465) **Proposed Rule**

- PHMSA proposed to explicitly permit remote monitoring and clarify that a rectifier inspection consists of recording amperage and voltage readings.
- For rectifiers being inspected remotely, PHMSA proposed to require the operator physically inspect the device during annual cathodic protection surveys (§ 192.465(a)) to ensure it has not been damaged.

G. Rectifier Remote Monitoring (§ 192.465) Comments

- The Associations, PST, and many other industry organizations supported allowing rectifier remote monitoring with annual physical inspections.
- The Associations recommend PHMSA adopt an annual physical inspection based on the cathodic protection survey requirements, rather than require inspections exactly when cathodic protection surveys take place. The commenter noted the proposed language could require an operator inspect a rectifier more than once annually if it affects multiple pipeline segments or if CP surveys occur over a few days.
- NPGA and other supporting entities supported the proposal but suggested that physical inspection should be required as needed based on rectifier malfunction rather than specifying annual inspections.

PHMSA Response:

- PHMSA agrees to clarify that physical inspection is expected to occur annually.
- Not all malfunctions would be readily apparent remotely and an operator has several opportunities to perform a once-annual physical inspection during other maintenance tasks, such as CP surveys.

G. Rectifier Remote Monitoring (§ 192.465) Comments

- One individual commenter opposes reducing the reduction of inspection standards and requests an increase of monitoring standards to align with industry practices.

PHMSA Response:

- The proposed rule codifies existing PHMSA interpretation and enforcement guidance of the requirement. Operators are not currently required to physically inspect a rectifier six times annually, but may continue to do so if that is their procedure.
- Depending on the technology employed, remote monitoring could enhance safety by allowing on-demand or real-time evaluation.

H. Atmospheric Corrosion

H. Atmospheric Corrosion (§ 192.481) **Background**

- Pipeline facilities exposed to the atmosphere (e.g. aboveground, in vaults, or indoors) are susceptible to atmospheric corrosion and must be cleaned and suitably coated (see § 192.479).
- The rate of atmospheric corrosion varies with environmental conditions such as humidity, pollution, and other factors.
- All exposed onshore gas pipelines must be inspected for atmospheric corrosion once every 3 years. If corrosion is found, the operator must protect against the corrosion as described in § 192.479.
- Virtually all distribution service lines include some aboveground component (e.g. risers and meter sets)

H. Atmospheric Corrosion (§ 192.481)
Background

- Comments on the DOT Notice of Regulatory Reform suggested changes to atmospheric corrosion requirements for distribution pipelines.
  - One suggestion to extend the inspection interval to 5 years, consistent with the required frequency of leakage surveys.
  - One suggestion to eliminate a specified inspection interval and instead manage atmospheric corrosion under DIMP
- Syncing the frequency of atmospheric corrosion assessments with leakage surveys would allow both tasks to be accomplished by a single crew during the same inspection.
- PHMSA is not aware of an incident caused by atmospheric corrosion on a distribution *service line*.

H. Atmospheric Corrosion (§ 192.481)
Proposed Rule

- PHMSA proposed to extend the atmospheric corrosion control inspection interval from every 3 calendar years to every 5 calendar years for distribution service pipelines in § 192.481.
- However, PHMSA proposed to require assessment within 3 years if atmospheric corrosion was identified on the previous inspection.
- PHMSA also proposed to clarify that consideration of corrosion threats under DIMP includes atmospheric corrosion. Significant atmospheric corrosion threats may require more frequent inspections or other measures to mitigate risks.

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H. Atmospheric Corrosion (§ 192.481) **Proposed Rule**

- PHMSA has determined that the low risk of atmospheric corrosion on service lines and safeguards in the proposed rule prevent adverse safety impacts.
  - Distribution mains and other higher-pressure lines are excluded from the proposed change.
  - The rule requires a shorter inspection interval if corrosion is identified.
  - Explicit consideration of atmospheric corrosion under DIMP may require an operator to take additional mitigative measures if there are significant atmospheric corrosion threats.

H. Atmospheric Corrosion (§ 192.481)

Comments

- The Associations and other industry entities support a 5-year interval on atmospheric corrosion inspections for service lines.
- The associations and NPGA suggested that a shorter 3-year interval when corrosion is identified is unnecessary if the facility is remediated.

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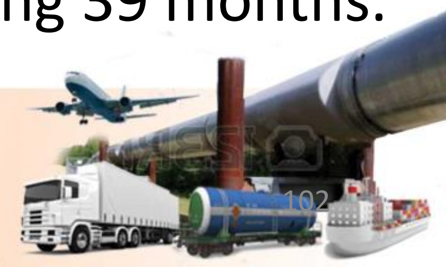
H. Atmospheric Corrosion (§ 192.481)
Comments

The Associations suggested the following remediation alternative

(d)If atmospheric corrosion is found on a service line **during the most recent inspection, then operators must:** (i) **Repair or replace portions of the service pipeline found to have atmospheric corrosion that could reduce the pipeline's integrity and apply new coating, as necessary, to all affected portions of the service pipeline that are above-ground within 12-months of identification of atmospheric corrosion; or**

(ii)**Meet the requirements of paragraph (c) of this section and perform** the next inspection of that pipeline or portion of pipeline within 3 calendar years, with an interval not exceeding 39 months.



H. Atmospheric Corrosion (§ 192.481) **Comments**

PHMSA Response:

- PHMSA has safety concerns with replacing a shorter reassessment interval with remediation when atmospheric corrosion has already been identified.
  - Remediation is already required by the existing §192.481(c), through reference to §192.479.
  - Evidence of corrosion is an indication that a corrosive environment may exist.
- Any final action must be consistent with public safety and environmental protection in accordance with the pipeline safety laws.
- PHMSA believes that the enhanced remediation alternative requires further analysis and notice and comment procedures to ensure that it is consistent with these goals.

H. Atmospheric Corrosion (§ 192.481)
Comments

- NPGA and supporting organizations requests clarification on whether 3-year interval when corrosion is identified applies to the whole system or just the location where corrosion was identified.
- NAPSR and others suggested a corresponding change to recordkeeping requirements to support the revised inspection intervals. Specifically, an operator should retain records for the last two inspections to ensure that their use of the 5-year inspection interval is supported.

PHMSA Response:

- The shorter inspection interval would apply to the service line on which the atmospheric corrosion was identified, PHMSA will clarify this in the final rule.
- PHMSA will clarify the recordkeeping requirements of this section in § 192.491(c) based on the comment from NAPSR to ensure the operator's inspection interval and inspection results are adequately documented.

H. Atmospheric Corrosion (§ 192.481) **Comments**

- PST generally opposes reducing corrosion inspection intervals, but recognizes that atmospheric corrosion hasn't been a factor in recent incidents. As a result, they stated that they mildly oppose this change and request more prescriptive corrosion monitoring regulations.
- NAPSR suggested PHMSA consider an alternative of establishing a shorter interval of 3-4 years for residential leak survey requirements, and that the atmospheric corrosion and leak surveys can be conducted simultaneously as proposed.
- American Assn. of Laboratory Accreditation requested a change from a prescriptive inspection interval to a risk-based determination with a maximum interval of 5 years not to exceed 63 months.

PHMSA Response:

- PHMSA determined that due to the low risk of atmospheric corrosion and the conditions in the proposed rule ensure that the safety of distribution service lines is maintained.
- PHMSA agrees that a prescriptive maximum interval is necessary, but is persuaded that 5 years is an appropriate maximum interval for atmospheric corrosion surveys for service line where no active corrosion or atmospheric corrosion threats have been identified.
- Explicit consideration of atmospheric corrosion under DIMP effectively serves as a risk-based determination not to exceed 5 years.

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H. Atmospheric Corrosion (§ 192.481) **Comments**

- The Associations requested removing of the term “evaluate” from §192.481(a). PHMSA did not present specific guidance and criteria for evaluation. A prescriptive “inspect and remediate” requirement coupled with explicit consideration through DIMP would meet PHMSA’s justification for revising §192.481 and the term “evaluate” is not necessary.

PHMSA Response:

- PHMSA’s intent was not to change the content of the inspection itself. PHMSA will consider removing the term “evaluate” consistent with the existing language in § 192.481
- As indicated in the comments, operators are required to evaluate corrosion under DIMP.

G. Rectifier Remote Monitoring and H. Atmospheric Corrosion

This concludes the PHMSA response to comments on Rectifier Remote Monitoring and Atmospheric Corrosion topics.

In light of comments received from the NPRM, PHMSA recommends the Committee consider adopting the proposal with the following changes:

- Regarding rectifier monitoring, require physical inspections of remotely monitored rectifier stations once each calendar year consistent with required CP surveys rather than exactly when CP surveys occur.
- With regard to atmospheric corrosion:
  - Remove the term “evaluate” consistent with the existing language in § 192.481.
  - Clarify recordkeeping requirements in § 192.491(c) to ensure operators retain records necessary to substantiate a 5-year inspection interval.
  - PHMSA does not recommend allowing remediation as an alternative to a shorter inspection interval when corrosion is found.

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G. Rectifier Remote Monitoring and H. Atmospheric Corrosion

Public Comments

G. Rectifier Remote Monitoring and H. Atmospheric Corrosion

GPAC Discussion

G. Rectifier Remote Monitoring and H. Atmospheric Corrosion

Committee Voting Slides

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to remote monitoring of rectifiers and atmospheric corrosion, are technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Regarding rectifier monitoring: require physical inspections of rectifier stations once each calendar year consistent with required CP surveys rather than exactly when CP surveys occur.
- Regarding atmospheric corrosion:
  - Remove the term “evaluate” from § 192.481, and
  - Revise § 192.491(c) to require operators retain records of the last two atmospheric corrosion inspections.

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Topics for Discussion

I. Welding Process Requirement
(§ 192.229 (b))

J. Pre-Testing Short Segments (§ 192.507 (d))

I. Welding Process Requirement (§ 192.229 (b))

- **Background:** the Gas Piping Technology Committee (GPTC) petitioned to extend the interval for remaining engaged in a welding process (the welding process requirement) from six months to at least twice each year, but not exceeding 7.5 months.
- Unlike the process requirement, most other welder requalification requirements use a flexible calendar year format.
- **Proposed Rule:** PHMSA proposed to extend the interval for engaging in a welding process to 7.5 months.

I. Welding Process Requirement

(§ 192.229 (b))

Comments

- No specific comments were submitted in opposition of the welder requalification proposal. Many industry commenters supported this item without additional comment.
- PST responded with “no comment” on this item.

PHMSA Response:

- PHMSA appreciates the feedback on the proposed rule

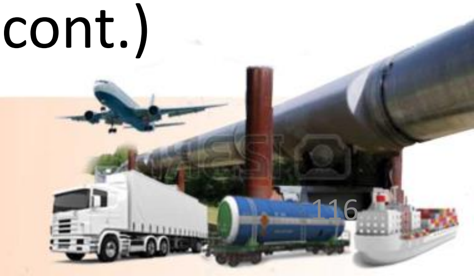
J. Pre-Testing Short Segments of Pipe and Fabricated Assemblies

J. Pre-Testing Short Segments (§ 192.507(d))

- **Background**
  - Generally pipeline facilities must be pressure tested after installation.
  - If post-installation testing is impracticable, certain components may be tested pre-installation.
    - Section 192.503(e) permits pre-installation testing of individual components, but excludes short sections of pipe and fabricated assemblies.
    - Section 192.505(d) permits pre-testing short segments of pipe and fabricated units on steel pipelines operating at a hoop stress of 30 percent or more.
    - There is no similar allowance for fabricated assemblies and short segments of pipe for lower-stress lines despite relatively lower risk.
- **Proposal:** PHMSA proposed to extend the allowance for pretested pipe and assemblies to steel pipe operating an MAOP producing a hoop stress less than 30 percent of SMYS but above 100 psig.

J. Pre-Testing Short Segments (§ 192.507(d)) Comments

- The Associations and many other industry entities generally supported PHMSA's proposal with the following suggestions:
  - Extend the requirement to pre-tested short segments of pipe and fabricated units for pipelines operating below 100 psi (§192.509).
  - Extend the requirement to short segments or prefabricated units installed on services and plastic pipelines (§§ 192.511 and 192.513).
- Many industry commenters and NAPSR stated support of this item without additional comment.
- PST does not object to extending the pre-testing provisions to lower stress pipelines as proposed. (cont.)



J. Pre-Testing Short Segments (§ 192.507(d)) Comments

- National Fuel estimated that an onsite pressure test adds between 15-25% (20% average) to the cost of a short segment pipeline replacement to repair an excavation damage, leak or visually questionable pipe joint. Assuming $500 per pressure test and a pressure test for each excavation damage related leak, the commenter estimated costs of approximately $8.8 million annually for pressure testing excavation damage repairs on mains.

PHMSA Response:

- It is not necessarily straightforward to extend pre-testing to other categories of lines (generally distribution lines) due to the proximity to customers and the differences in design, construction, inspection, and testing requirements for such facilities compared with higher-pressure lines.
- PHMSA has determined that extending pretesting requirements to pipe below 100 psi, plastic pipe, and service lines requires additional analysis with notice and public comment procedures.

J. Pre-Testing Short Segments (§ 192.507(d)) Comments

- The Associations and many other industry entities suggested removing or revising the term "hydrostatic," as natural gas, inert gas, and air are also allowable test media for pipelines operating at a hoop stress less than 30% of SMYS.

PHMSA Response:

- PHMSA agrees with comments to remove the word "hydrostatic" from § 192.507(d) since § 192.507 allows pressure tests with other media.

I. Welding Process Requirement and J. Pre-Testing Short Segments

This concludes the PHMSA response to comments on the Welding Process Requirement and Pre-Testing topics.

In light of comments received from the NPRM, PHMSA recommends the Committee adopting the proposal with the following changes:

- Regarding the welding process requirement, no changes to the NPRM are recommended.
- With regard to pre-testing:
  - Remove the word “hydrostatic” from proposed §192.507(d).
  - PHMSA does not recommend extending the proposed pre-testing allowance beyond § 192.507 in this final rule. PHMSA may consider this issue in a future rulemaking action.

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I. Welding Process Requirement and J. Pre-Testing Short Segments

Public Comments

I. Welding Process Requirement and J. Pre-Testing Short Segments

GPAC Discussion

I. Welding Process Requirement and J. Pre-Testing

Committee Voting Slides

The proposed rule as published in the Federal Register and the Draft Regulatory Evaluation, with regard to welder requalification and pre-testing short segments of pipe and fabricated units, are technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Regarding pre-testing, remove the word “hydrostatic” from proposed §192.507(d).

Committee Report

Committee Voting Slides

The transcript of this meeting (duly recorded and accurately transcribed), together with the presentation slides documenting the committee's votes during this meeting, represent the report of this proceeding.

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