

**BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
WASHINGTON, D.C.**

Pipeline Safety: Gas Pipeline Regulatory
Reform

}

Docket No. PHMSA-2016-0136

COMMENTS IN RESPONSE TO GAS PIPELINE ADVISORY COMMITTEE MEETING

**FILED BY
AMERICAN GAS ASSOCIATION
AMERICAN PETROLEUM INSTITUTE
AMERICAN PUBLIC GAS ASSOCIATION
GPA MIDSTREAM ASSOCIATION
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA**

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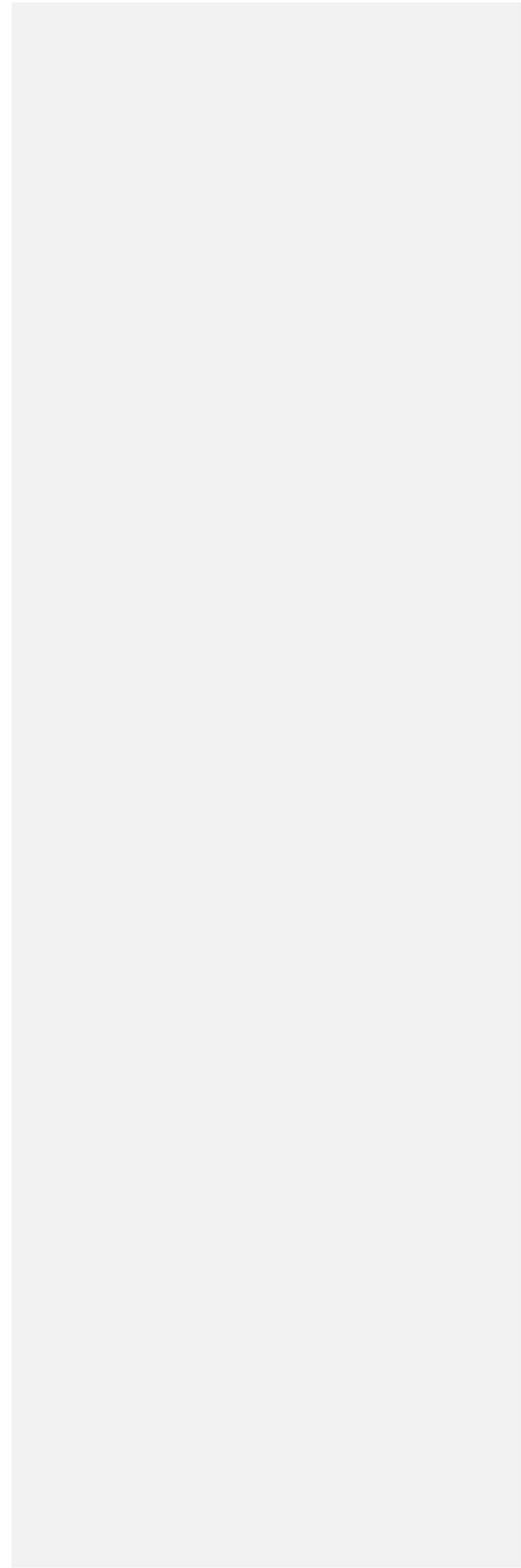


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I. Introduction

The American Gas Association (AGA),¹ American Petroleum Institute (API),² American Public Gas Association (APGA),³ GPA Midstream Association,⁴ and Interstate Natural Gas Association of America (INGAA)⁵ (jointly “the Associations”) submit these comments for consideration by the Pipeline and Hazardous Materials Safety Administration (PHMSA) regarding the gas pipeline provisions of PHMSA’s Notice of Proposed Rulemaking, “Pipeline Safety: Gas Pipeline Regulatory Reform” (“Proposed Rule” or “NPRM”),⁶

On October 7, 2020, PHMSA convened a Gas Pipeline Advisory Committee (GPAC) meeting to review the Proposed Rule.⁷ The meetings provided the GPAC Members, PHMSA representatives, pipeline operators, and the public the opportunity to discuss and provide input on the Proposed Rule. Below the Associations propose changes to the NPRM’s regulatory text to reflect the votes and discussions held by the GPAC and PHMSA. The Associations believe that incorporating these proposed changes into the final rule will ensure that the rule enhances pipeline safety, provides clear requirements, and leads to an efficient use of pipeline operators’ resources.

¹ The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 74 million residential, commercial and industrial natural gas customers in the U.S., of which 95 percent — over 71 million customers — receive their gas from AGA members. Today, natural gas meets more than one-fourth of the United States’ energy needs.

² API is the national trade association representing all facets of the oil and natural gas industry, which supports 9.8 million U.S. jobs and 8 percent of the U.S. economy. API’s more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation’s energy and are backed by a growing grassroots movement of more than 25 million Americans.

³ APGA is the national, non-profit association of publicly-owned natural gas distribution systems. APGA was formed in 1961 as a non-profit, non-partisan organization, and currently has over 740 members in 37 states. Overall, there are nearly 1,000 municipally-owned systems in the U.S. serving more than five million customers. Publicly-owned gas systems are not-for-profit retail distribution entities that are owned by, and accountable to, the citizens they serve. They include municipal gas distribution systems, public utility districts, county districts, and other public agencies that have natural gas distribution facilities.

⁴ GPA Midstream Association has served the U.S. energy industry since 1921 and has nearly 70 corporate members that directly employ more than 75,000 employees that are engaged in a wide variety of services that move vital energy products such as natural gas, natural gas liquids (“NGLs”), refined products and crude oil from production areas to markets across the United States, commonly referred to as “midstream activities”. The work of our members indirectly creates or impacts an additional 450,000 jobs across the U.S. economy. GPA Midstream members recover more than 90% of the NGLs such as ethane, propane, butane, and natural gasoline produced in the United States from more than 400 natural gas processing facilities. In 2017-2019 period, GPA Midstream members spent over \$105 billion in capital improvements to serve the country’s needs for reliable and affordable energy.

⁵ INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 26 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA’s members operate nearly 200,000 miles of pipelines and serve as an indispensable link between natural gas producers and consumers.

⁶ Pipeline Safety: Gas Pipeline Regulatory Reform, 85 Fed. Reg. 35,240 (June 9, 2020).

⁷ Pipeline Safety: Meeting of the Gas Pipeline Safety Advisory Committees (October 7, 2020).

II. Monetary Damage Threshold Comments

PHMSA should incorporate both recommendations passed by the GPAC to adopt an appropriate inflation adjustment based on the Consumer Price Index (CPI) at the date of final rule publication and incorporate a formula into 49 CFR Part 191 for future periodic updates to the threshold.

The Associations support adjusting the property damage threshold for inflation based on the effective date of the rule and periodically thereafter. The cost of repairing or remediating incident damage in today's environment is far greater than it was in 1984. Even with the inflation adjustment, more minor events will be reported as an incident than would have been reported in 1984. The increase in the reporting threshold will reduce the number of calls made to the National Response Center (NRC) for minor events that are easily remediated by the operator.

GPAC member Ms. Sara Gosman expressed concerned that by adjusting the threshold for inflation, "PHMSA would be losing data that could be used to support the agency's analysis of the benefits of the proposed regulation in the future."⁸ This issue was addressed by PHMSA in its response slides but additionally, as noted by GPAC member Mr. Andy Drake: "A lot of the data that we are collecting here would be collected under the annual report the operators are submitting. It would just be reclassified."⁹

III. Atmospheric Corrosion Inspection Intervals Comments

PHMSA should incorporate both recommendations passed by the GPAC on Atmospheric Corrosion control monitoring: (1) to require operators to retain records of the last two atmospheric corrosion inspections and (2) to allow operators to remain on the 5-year atmospheric corrosion inspection cycle for pipelines where atmospheric corrosion is found, if the corrosion is remediated and there is no evidence of systemic atmospheric corrosion.

In the Preliminary Regulatory Impact Assessment, PHMSA identified a \$61,042,456 estimated cost savings¹⁰ related to the changes in §192.481: *Atmospheric Corrosion Monitoring*. These savings are realized only if operators can align Atmospheric Corrosion checks with the 5-year inspection interval for service lines. These savings represent 47% of the cost savings identified for the entire rulemaking. If PHMSA does not incorporate the recommendation from the GPAC included in voting slide #113, the cost savings attributed to this regulatory reform rulemaking will not be realized.

GPAC member Mr. Rich Worsinger described the existing process an operator takes when AC is identified on a service line. "Where we find rust, we then prepare a work order, come back, and we sand it and prime it and paint it.... If you fully remediate that, I question why would you want to look at that again in three years? We're not finding those issues where we've remediated the meter set, some surface rust on the pipe, and we go back three years later, and it hasn't begun rusting again."¹¹ Like Mr. Worsinger said, these remediated service lines are "like new." His comments demonstrate the

⁸ GPAC Transcript. Page 175.

⁹ GPAC Transcript. Page 185.

¹⁰ PHMSA PRIA. Page 32. Table 24: Estimated Annualized Cost Savings from the Proposed Changes for Atmospheric Corrosion Monitoring.

¹¹ GPAC Transcript. Page 289. Line 9.

confidence operators have in the negligible likelihood of identifying AC on these “new” service lines, thus negating the need for a shorter inspection interval.

IV. Pressure Vessel Testing Requirement Comments

The Associations continue to support PHMSA’s proposal to use a 1.3 times Maximum Allowable Operating Pressure (MAOP) test factor for pressure vessels. In August, the Associations filed comments in this docket supporting the Agency’s proposal to return to the 1.3 test factor previously applied through incorporation by reference of the ASME Boiler and Pressure Vessel Code (BPVC).

In comments submitted on the Proposed Rule, the Pipeline Safety Trust (PST) voiced concern regarding PHMSA’s statutory authority to apply a 1.3 test factor requirement to pressure vessels installed after July 14, 2004.¹² This concern was also raised by public members of the GPAC during its October 2020 meeting.¹³ The PST argued that the proposed changes would violate the non-retroactivity provision in 49 U.S.C. § 60104(b) of the Pipeline Safety Act. The Associations disagree.

Section 60104(b) of the Pipeline Safety Act does not apply to PHMSA’s proposed changes to align § 192.153(e) with the ASME BPVC. Section 60104(b) prohibits application of a *new* design, construction, or initial testing standard to existing facilities. That is not the action PHMSA is taking here. Rather, PHMSA is proposing to reinstate the design standard that applied to these vessels between 2004 and 2015 prior to the Miscellaneous Final Rule and subsequent stay of enforcement. Contrary to PST’s assertions, PHMSA’s proposed action would avoid and correct a retroactive application of a design standard rather than create a new one.

Background

PHMSA’s current proposal to codify a 1.3 test factor for pressure vessels installed between July 14, 2004 and the effective date of the final rule is the last step after numerous years of public discussion and agency evaluation of this issue. On June 14, 2004, PHMSA incorporated the 2001 edition of the ASME BPVC by reference in § 192.153.¹⁴ That edition applied a test factor of 1.3 times Maximum Allowable Working Pressure (MAWP) to pressure vessels fabricated by welding. Between 2004 and 2015, PHMSA continued to accept the 1.3 test factor through subsequently incorporated editions of the ASME standard, and the natural gas pipeline industry followed that standard accordingly in construction of pressure vessels.¹⁵

¹² Comments of the Pipeline Safety Trust on the Gas Pipeline Regulatory Reform Proposed Rule, No. PHMSA-2018-0046-0042 (Aug. 11, 2020), <https://beta.regulations.gov/comment/PHMSA-2018-0046-0042>.

¹³ Transcript of Gas Pipeline Advisory Committee Meeting at 109: 13-22 (Oct. 7, 2020).

¹⁴ Pipeline Safety: Periodic Updates to Pipeline Safety Regulations (2001), 69 Fed. Reg. 32,886, 32,893 (June 14, 2004). *See also*, Pipeline Safety: Gas Pipeline Regulatory Reform, 85 Fed. Reg. 35,248 (June 9, 2020).

¹⁵ PHMSA subsequently incorporated other editions of the ASME BPVC by reference but the 1.3 test factor was included in those documents. *See* Pipeline Safety: Update of Regulatory References to Technical Standards, 71 Fed. Reg. 33,402, 33,404 (June 9, 2006). *See also*, Pipeline Safety: Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Edits, 75 Fed. Reg. 48,593, 48,598 (Aug. 11, 2010). All three editions listed a 1.3 times MAWP test factor for pressure vessels.

On March 11, 2015, PHMSA departed from the long-standing use of the 1.3 test factor when it amended § 192.153 and introduced a test factor of 1.5 times MAOP.¹⁶ This change could have rendered numerous pressure vessels constructed between 2004 and 2015 non-compliant. INGAA filed a timely petition for reconsideration, noting that PHMSA did not provide a technical justification for changing the test factor from 1.3 times MAWP to 1.5 times MAOP and raising concerns about retroactive application of a new design and initial testing requirement to vessels that had been installed since 2004.¹⁷ PHMSA denied the petition but agreed to study whether there were any safety concerns with using a 1.3 test factor. Thereafter, INGAA filed a petition for review of that decision in the U.S. Court of Appeals for the D.C. Circuit.¹⁸ That petition has been held in abeyance to allow PHMSA an opportunity to conduct a technical study and address INGAA's position. PHMSA also issued a stay of enforcement agreeing not to take any enforcement action relating to violations of §§ 192.153(e) and 192.505(b) that "arise from the installation of pressure vessels that are: (1) covered by 49 C.F.R. §§ 192.153(a)-(b) and 192.165(b)(3); and (2) were put into service between July 14, 2004 and October 1, 2015."¹⁹ The stay of enforcement is still in effect today.

Consistent with the commitment made in the decision denying INGAA's petition for reconsideration, PHMSA commissioned a report by the Oak Ridge National Laboratories (ORNL) on the technical equivalency between the 1.5 test factor in the 1992 edition of the ASME BPVC and 1.3 test factor in the 2001 and subsequent editions of the ASME BPVC. The 1.3 test factor is used in the 2007 edition of the ASME BPVC that is currently incorporated by reference in PHMSA's regulations and the 2015 edition that was current at the time of the ORNL analysis. The ORNL study, presented to the GPAC in 2017,²⁰ found that "[h]ydrostatic pressure testing limits in the 2015 edition [1.3 test factor] provide equivalent safety to hydrostatic pressure testing limits in the 1992 edition [1.5 test factor]."²¹

On June 9, 2020, PHMSA initiated this proceeding by proposing certain changes to the gas pipeline safety regulations. One of the proposals was to amend § 192.153 to clarify that the 1.3 test factor applied to pressure vessels installed between July 14, 2004 and the effective date of the rule.²² In other words, PHMSA proposed to reinstate the requirements in effect prior to the agency's 2015 Miscellaneous Rule, consistent with the terms of the stay of enforcement.²³

¹⁶ Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations, 80 Fed. Reg. 12,762, 12,778 (Mar. 11, 2015).

¹⁷ INGAA Petition for Reconsideration, Docket No. PHMSA-2010-0026, <https://www.regulations.gov/document?D=PHMSA-2010-0026-0057> (April 10, 2015).

¹⁸ Petition for Review, *Interstate Natural Gas Assn's v. Dept. of Transp.*, No. 15-1343 (D.C. Cir. filed Sept. 30, 2015).

¹⁹ See Joint Motion to Hold Proceeding in Abeyance, Exhibit A, No. 15-1343 (D.C. Cir. filed Nov. 13, 2015).

²⁰ Ms. Sara Gosman, a public member of the GPAC who is a member of PST's Board of Directors, supported PHMSA's decision to conduct the ORNL study during the 2017 meeting. Ms. Gosman stated that "PHMSA using this device to learn more about a particular issue to decide whether a particular standard is appropriate for regulation is exactly what I think PHMSA should be doing. So, I'm really pleased to see this." Transcript of Joint GPAC and LPAC Committee Meeting at 206:13–207:3 (Dec. 13, 2017).

²¹ OAK RIDGE NATIONAL LABORATORY, ASME BOILER AND PRESSURE VESSEL CODE EVALUATION AND EQUIVALENCE STUDY FOR LIQUIFIED NATURAL GAS FACILITIES 211, 235, 237, 266 (2017).

²² Pipeline Safety: Gas Pipeline Regulatory Reform, 85 Fed. Reg. at 35,247.

²³ Although pressure vessels were handled in a different rulemaking (PHMSA-2010-0026), the Agency included its proposed regulatory changes in response to the INGAA Petition for Reconsideration and subsequent litigation in this Proposed Rule.

Impact of PHMSA's Latest Proposal to Modify § 192.153

PHMSA's proposal to modify § 192.153 is not prohibited as a retroactive change. The agency is not proposing a new standard to apply to preexisting facilities.²⁴ For pressure vessels installed between July 14, 2004 and the effective date of the final rule, the Agency is simply reinstating the requirements that existed in § 192.153 prior to the 2015 Miscellaneous Final Rule and consistent with the stay of enforcement. As PHMSA explained at the GPAC meeting in October 2020, the proposed changes to § 192.153 "will not force any operator to take an action to re-design or construct an existing facility."²⁵ Per the NPRM, "pressure vessels that were properly designed and tested in accordance with the ASME BPVC since 2004 would be in compliance with the revised PSR, provided they were tested to at least 1.3 times MAOP."²⁶ Thus the regulation in fact avoids what would have been a retroactive change made by the 2015 Miscellaneous Rule.

Section 60104(b) of the Pipeline Safety Act prohibits PHMSA from applying new design, construction, or initial inspection standards to existing facilities. In enacting this legislation, Congress was attempting to address concerns of pipeline operators that had facilities already in existence when the federal pipeline safety regulations were enacted. Here, PHMSA is not trying to apply a new design or initial testing standard retroactively in this rulemaking proceeding.²⁷ Rather, as previously discussed, PHMSA is reinstating the test factor that applied to pressure vessels installed prior to the 2015 rule consistent with the terms of the stay of enforcement.²⁸ Restoring the 1.3 test factor does not create a new obligation. It merely codifies existing policy and provides, according to ORNL, an equivalent measure of safety.

The GPAC also discussed whether the NPRM in 2011 provided notice to the industry that PHMSA expected operators to apply a 1.5 test factor to pressure vessels.²⁹ The Associations emphasize that an NPRM does not create a legal obligation.³⁰

²⁴ The Supreme Court has explained that "a regulation has retroactive effect when it takes away or impairs vested rights acquired under existing laws, or creates a new obligation, imposes a new duty, or attaches a new disability, in respect to transactions or considerations already past." *Mejia v. Gonzales*, 499 F. 3d. 991, 997 (9th Cir. 2007) (quoting *I.N.S. v. St. Cyr*, 533 U.S. 289 (2001)).

²⁵ GPAC Slide Deck at 42 (Oct. 7, 2020), <https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1127>; *See also*, Transcript of Gas Pipeline Advisory Committee Meeting at 86: 14-17 (Oct. 7, 2020).

²⁶ Pipeline Safety: Gas Pipeline Regulatory Reform, 85 Fed. Reg. at 35,248.

²⁷ PHMSA legal staff further confirmed that "the purpose of [60104(b)] is to prevent PHMSA from requiring operators to dig up existing pipeline that was installed according to the code at the time. . . . You know, we cannot make operators go dig up the pipeline to comply with those new design standards. That's not really what's going on here." Transcript of Gas Pipeline Advisory Committee Meeting at 126:1-10 (Oct. 7, 2020).

²⁸ The 2015 modifications to section 192.153 were ultimately stayed and that stay remains in effect today. As a result, an operator's obligation today remains limited to the 1.3 test factor until the stay is lifted.

²⁹ Transcript of Gas Pipeline Advisory Committee Meeting at 128: 6-10, 17-22; 129:1-2; 138:19-22 (Oct. 7, 2020).

³⁰ Courts have historically held that proposed rules have no legal effect and do not reflect an Agency's final, considered judgment. *See Commodity Futures Trading Comm'n v. Schor*, 478 US 833 (1986) ("It goes without saying that a proposed regulation does not represent an agency's considered interpretation of its statute and that an agency is entitled to consider alternative interpretations before settling on the view it considers most sound.") *See also, US v. Springer*, 354 F.3d 772 (11th Cir. 2004) (finding that "[a] major purpose of formal rulemaking is to ensure that agencies gather as much relevant information as possible before promulgating final rules that will have the force and effect of law. For this reason, an agency that exercises its discretion to propose a rule has no duty to promulgate its proposal as a final rule. Thus, it is well settled that proposed regulations have no legal effect.").

V. Consolidated Recommendations for Changes to Regulatory Text of Proposed Rule

Below is a consolidated set of the Associations’ proposed modifications to the NPRM regulatory text in red.

§ 191.3 Definitions

Incident means any of the following events:

(1) [. . .]

(ii) Estimated property damage of \$122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost; or [. . .]

Commented [A1]: See above comments. Per Oct 7 GPAC Meeting Topic C Voting Slide (62), the Associations request that PHMSA incorporate both recommendations passed by the GPAC to adopt an appropriate inflation adjustment based on the CPI at the date of final rule publication and incorporate a formula in Part 191 for future updates like proposed FRA procedures.

~~§ 191.12 – Distribution system: Mechanical Fitting Failure Report.~~

~~Each mechanical fitting failure, as required by §192.1009, must be submitted on a Mechanical Fitting Failure Report Form PHMSA F 7100.1-2. An operator must submit a mechanical fitting failure report for each mechanical fitting failure that occurs within a calendar year not later than March 15 of the following year (for example, all mechanical failure reports for calendar year 2011 must be submitted no later than March 15, 2012). Alternatively, an operator may elect to submit its reports throughout the year. In addition, an operator must also report this information to the State pipeline safety authority if a State has obtained regulatory authority over the operator's pipeline.~~

Commented [A2]: Per Oct 7 GPAC Meeting Topic F Voting Slide (91): “The proposed rule as published in the Federal Register and Draft Regulatory Evaluation, with regard to mechanical fitting failure reports are technically feasible, reasonable, cost-effective, and practicable.”

The Associations support PHMSA’s proposal to eliminate the MFF reporting requirements and include a count of leaks due to MFFs to the gas distribution annual report form. The Associations believe this still provides transparency for the data as well as reduces regulatory burden without compromising safety.

§ 192.121 Design of Plastic Pipe

[. . .]

(c) Polyethylene (PE) pipe requirements.

...

Commented [A3]: Per Oct 7 GPAC Meeting Topic D Voting Slide (90) “...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.”

PE PIPE—MINIMUM WALL THICKNESS AND SDR VALUES

Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
1/2" CTS	0.090	7
3/4" CTS	0.090	9.7
1/2" IPS	0.090	9.3
3/4" IPS	0.095	11

1" CTS	0.101 <u>0.099</u>	<u>11.5</u>
1" IPS	0.119	11
1¼" IPS	0.151	11
	...	

§ 192.153 Components fabricated by welding

- (a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, see §192.7).
- (b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section 1 of the ASME BPVC (*Rules for Construction of Pressure Vessels* as defined in either Section VIII, Division 1 or Section VIII, Division 2; incorporated by reference, see §192.7), except for the following:
 - (1) Regularly manufactured butt-welding fittings.
 - (2) Pipe that has been produced and tested under a specification listed in appendix B to this part.
 - (3) Partial assemblies such as split rings or collars.
 - (4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.
- (c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.
- (d) Except for flat closures designed in accordance with the ASME BPVC (Section VIII, Division 1 or 2), flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage or more, or is more than 3 inches in (76 millimeters) nominal diameter.
- (e) The test requirements for pressure vessels, defined for this paragraph as components with a design pressure established in accordance with paragraph (a) or paragraph (b) of this section are as follows:
 - (1) Pressure vessels installed after July 14, 2004 are not subject to the strength testing requirements of §192.505(b) and §192.619(a)(2), but must be pressure tested in accordance with paragraph (a) or paragraph (b) of this section and with a test factor of at least 1.3 times MAOP.
 - (2) Pressure vessels must be pressure tested for the duration specified as follows:
 - (i) Pressure vessels installed after July 14, 2004, but before [Insert the Effective Date of the Rule] are exempt from §§ 192.505(c), 192.505(d), and 192.507(c) and must instead be tested for a duration consistent with the ASME BPVC requirements referenced in paragraph (a) or (b) of this section.

- (ii) Pressure vessels installed on or after [EFFECTIVE DATE OF FINAL RULE] must be tested for the duration specified in either § 192.505(c), 192.505(d), 192.507(c), or 192.509(a), whichever is applicable for the pipeline in which the component is being installed.
- (3) After [EFFECTIVE DATE OF FINAL RULE], if a newly manufactured pressure vessel is relocated to a pipeline facility after an initial pressure test by the manufacturer, the operator must either:
 - (i) Pressure test the vessel in-place after it has been transported and placed at its installation location in accordance with the requirements of this section; or
 - (ii) Visually inspect the pressure vessel and confirm that the component was not damaged during transportation and placement at its installation location into the pipeline. Inspection records for the component must be kept for the operational life of the pressure vessel. If the pressure vessel has been damaged, it must be remediated or retested in accordance with the ASME BPVC requirements referenced in paragraphs (a) or (b) of this section.
- (4) After [EFFECTIVE DATE OF FINAL RULE], if a pressure vessel that has previously been in operation is relocated to a new fixed location, other than a relocation of a pressure vessel for temporary maintenance and repair activities, the operator must:**
 - (i) Confirm that the relocated vessel meets current design and construction requirements;
 - (ii) Pressure test the vessel after it has been transported and placed at its installation location in accordance with the requirements of this section; and
 - (iii) Visually inspect the pressure vessel and confirm that the component was not damaged during transportation and placement at its installation location. Inspection records for the component must be kept for the operational life of the pressure vessel. If the pressure vessel has been damaged, it must be remediated or retested in accordance with the ASME BPVC requirements referenced in paragraphs (a) or (b) of this section.
- (5) The requirements of paragraph (4) do not apply to pressure vessels that are used for temporary maintenance and repair activities, including but not limited to portable launchers or receivers, temporary odorant tanks, and blowdown mitigation equipment. Pressure vessels used for temporary maintenance and repair activities must be visually inspected for safety and integrity prior to use.

Commented [A4]: Per Oct 7 GPAC Meeting Topic B Voting Slide (51): "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."

Not all vessels are placed on supports (some are installed on pads, foundations, etc.) so the Associations recommend simply saying "placed at its installation location."

Commented [A5]: Per Oct 7 GPAC Meeting Topic B Voting Slide (51): "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."

Commented [A6]: Per Oct 7 GPAC Meeting Topic B Voting Slide (51): "Clarify that the retesting requirements applicable to pressure vessels do not apply to those pressure vessels that are used for temporary maintenance and repair activities, such as portable launchers or receivers, temporary odorant tanks, blow down equipment, and other similar equipment, but they must be inspected for safety and integrity prior to usage."

§ 192.465 External corrosion control: monitoring

[. . .]

- (b) Cathodic protection rectifier or other impressed current power source must be periodically inspected as follows:
 - (1) Each cathodic protection rectifier or impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 1/2 months between inspections, to ensure adequate amperage and voltage levels needed to provide cathodic protection are maintained. This may be done either through remote measurement or through an onsite inspection of the rectifier.

- (2) Each remotely monitored rectifier must be physically inspected for continued safe and reliable operation at the frequency of cathodic protection tests required under whenever cathodic protection tests are performed pursuant to §192.465(a).

Commented [A7]: Per Oct 7 GPAC Meeting Topic G Voting Slide (111): "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."

§ 192.481 Atmospheric corrosion control: Monitoring

- (a) Each operator must inspect and evaluate each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore other than a Service Line	At least once every 3 calendar years, but with intervals not exceeding 39 months
Onshore Service Line	At least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in paragraph (d) of this section
Offshore	At least once each calendar year, but with intervals not exceeding 15 months

- (b) During inspections, the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbanded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.
- (c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by §192.479.
- (d) If atmospheric corrosion is found on a service line during the most recent inspection, then at least one of the following requirements must be met:
- (1) The next inspection of that service pipeline or portion of pipeline must be within 3 calendar years, with an interval not exceeding 39 months, or
 - (2) The operator shall:
 - (i) Verify there is no evidence of systemic atmospheric corrosion due to the environment or similar factors; and
 - (ii) 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.

Commented [A8]: Per Oct 7 GPAC Meeting Topic H Voting Slide (113): "If atmospheric corrosion is found, evaluated, and remediated following an inspection, and there is no evidence of systemic atmospheric corrosion due to the environment or similar factors, the operator can inspect for atmospheric corrosion on a 5-year cycle rather than the proposed 3-year cycle."

§ 192.491 Corrosion control records.

- (a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner, or spacing, need not show specific distances to each buried anode.
- (b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.
- (c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that operators must maintain a record of the two prior inspections

conducted pursuant to § 192.481, and records related to §§192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

Commented [A9]: Per Oct 7 GPAC Meeting Topic H Voting Slide (112): "Revise 192.491(c) to require operators retain records of the last two atmospheric corrosion inspections."

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

- (a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.
- (b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium—
 - (1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or
 - (2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.
- (c) The pressure must be maintained at or above the test pressure for at least 1 hour.
- (d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation **hydrostatic** pressure test must be conducted in accordance with the requirements of this section.

Commented [A10]: Per Oct 7 GPAC Meeting Topic J Voting Slide (125): "Regarding pre-tested, remove the word "hydrostatic" from proposed §192.507(d)."

§ 192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

[. . .]

(c) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation pressure test must be conducted in accordance with the requirements of this section.

Commented [A11]: PHMSA notes on GPAC Slide 117 that "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."

The Associations support PHMSA affirming in a future rulemaking that pretesting fabrications and short segments meets the testing requirements under §§ 192.509, 192.511 and 192.513.

§ 192.511 Test requirements for service lines.

[. . .]

(d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation pressure test must be conducted in accordance with the requirements of this section.

Commented [A12]: PHMSA notes on GPAC Slide 117 that "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."

The Associations support PHMSA affirming in a future rulemaking that pretesting fabrications and short segments meets the testing requirements under §§ 192.509, 192.511 and 192.513.

§ 192.513 Test requirements for plastic pipelines.

[. . .]

(e) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation pressure test must be conducted in accordance with the requirements of this section.

Commented [A13]: PHMSA notes on GPAC Slide 117 that "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."

The Associations support PHMSA affirming in a future rulemaking that pretesting fabrications and short segments meets the testing requirements under §§ 192.509, 192.511 and 192.513.

§ 192.740 Pressure regulating, limiting, and overpressure protection - Individual service lines directly connected to regulated gathering or transmission pipelines.

[. . .]

- (c) This section does not apply to equipment installed on:
 - (1) Service lines that only serve engines that power irrigation pumps;

- (2) Service lines included in a distribution integrity management plan meeting the requirements of subpart P of this part; **and**
- (3) Service lines directly connected to unregulated gathering or production pipelines; **and**
- (4) ~~Pipe segments upstream of either: the inlet to the first pressure regulator, the connection to customer owned piping, or the outlet of the meter, whichever is further upstream.~~

Commented [A14]: Per Oct 7 GPAC Meeting Topic A Voting Slide (33): "Remove paragraph 192.740(c)(4)."

§ 192.1003 What do the regulations in this subpart cover?

- (a) *General.* Unless exempted in paragraph (b) of this section this subpart prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator must follow the requirements in this subpart.
- (b) Exceptions. This subpart does not apply to:
 - (1) Individual service line directly connected to a, production, or unregulated gathering pipeline.
 - (2) Individual service lines directly connect to either a transmission or regulated gathering pipeline and maintained in accordance with §192.740(a) and (b); and
 - (3) Master meter systems.

~~§ 192.1009 What must an operator report when a mechanical fitting fails?~~

- ~~(a) Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit a report on each mechanical fitting failure, excluding any failure that results only in a nonhazardous leak, on a Department of Transportation Form PHMSA F-7100.1-2. The report(s) must be submitted in accordance with §191.12.~~
- ~~(b) The mechanical fitting failure reporting requirements in paragraph (a) of this section do not apply to the following:

 - ~~(1) Master meter operators;~~
 - ~~(2) Small LPG operator as defined in §192.1001; or~~
 - ~~(3) LNG facilities.~~~~

Commented [A15]: Per Oct 7 GPAC Meeting Topic F Voting Slide (91): "The proposed rule as published in the Federal Register and Draft Regulatory Evaluation, with regard to mechanical fitting failure reports are technically feasible, reasonable, cost-effective, and practicable."

The Associations support PHMSA's proposal to eliminate the MFF reporting requirements and include a count of leaks due to MFFs to the gas distribution annual report form. The Associations believe this still provides transparency for the data as well as reduces regulatory burden without compromising safety.

Respectfully submitted,
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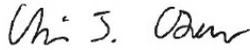
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