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-2018-0046

COMMENTS

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AMERICAN GAS ASSOCIATION
AMERICAN PETROLEUM INSTITUTE
AMERICAN PUBLIC GAS ASSOCIATION
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

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I. Introduction

The American Gas Association (AGA),[1] American Petroleum Institute (API),[2] American Public Gas Association (APGA),[3] and Interstate Natural Gas Association of America (INGAA)[4] (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").[5] Pipeline safety is the top priority of the Associations and our members. In general, the Associations support PHMSA's proposal to repeal, replace, or modify existing regulations without compromising safety. The proposed recommendations outline changes which would allow operators more flexibility, increase work efficiency by combining activities such as performing inspections on pipelines, and consolidate reporting for distribution fittings, while continuing to ensure the safe operation of our nation's gas pipeline system. These recommendations support PHMSA's stated purpose of this rulemaking, namely to "ease regulatory burdens on the construction, operation, and maintenance of gas transmission, distribution, and gathering pipeline systems."[6]

Below, the Associations offer detailed comments to assist PHMSA in developing a final rule that enhances pipeline safety, provides clear requirements, and leads to an efficient use of pipeline operators' resources. The Associations wish to highlight the following key recommendations:

1. PHMSA Should Not Define the "Service Line" Portion of a Farm Tap in Section 192.740
2. PHMSA Should Adjust the Monetary Damage Threshold Periodically for Reporting Incidents in Section 191.3
3. PHMSA Should Clarify the Physical Inspection Interval for Remotely Monitored Rectifier Stations
4. PHMSA Should Clarify the Atmospheric Corrosion Monitoring Intervals for Gas Distribution Service Lines which have been Remediated in Section 192.481

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[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] INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 25 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.

[5] Pipeline Safety: Gas Pipeline Regulatory Reform, 85 Fed. Reg. 35,240 (June 9, 2020) [hereinafter, *NPRM*].

[6] *Id.* at 35,241.

5. PHMSA Should Clarify its Minimum Wall Thickness Requirements for 1-inch CTS pipe in Section 192.121
6. The Associations Support PHMSA's Proposal to Align Pressure Vessel Testing Requirements with the ASME Boiler and Pressure Vessel Code (BPVC) and Recommend Modifications to Better Align Part 192 and the ASME BPVC
7. PHMSA Should Extend the Allowance for Pre-tested Short Segments of Pipe and Fabricated Units to Pipelines which Operate at Less Than 100 Pounds Per Square Inch (psi)

II. PHMSA Should Not Define the "Service Line" Portion of a Farm Tap in Section 192.740

Section 192.740 of 49 C.F.R. currently provides requirements for operators to inspect and test pressure regulating, limiting, and overpressure protection devices on "individual service lines directly connected to production, gathering, or transmission pipelines." These lines are commonly referred to as "farm taps." In the NPRM, PHMSA proposed to add §192.740(c)(4) which would specify that §192.740 does not apply to 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."[7] Based on the preamble text, it appears that PHMSA is proposing §192.740(c)(4) in order to define the portion of the farm tap piping that is regulated as a service line.[8] Given the diversity of farm tap configurations in the United States, the Associations object to this definition for the service line portion of a farm tap and urge PHMSA to consider an alternate approach that better aligns with past Gas Pipeline Advisory Committee (GPAC) recommendations. PHMSA should remove proposed §192.740(c)(4) and instead update §192.3, as discussed below.

It is neither practicable nor necessary for safety to establish a uniform service line starting point for every transmission line farm tap. As PHMSA acknowledged just four months ago,[9] farm taps are configured in many different ways, reflecting the diverse nature of America's natural gas pipeline system. It is impracticable and unrealistic for PHMSA to prescribe that distribution service line piping begins at the exact same point for every farm tap. Under proposed §192.740(c)(4), the distribution service line would start at the first pressure regulator on most farm taps because the meter and customer-owned piping are generally downstream of a pressure regulator. Gas transmission operators often transfer custody to local distribution companies (LDCs) at some point along the farm tap, which could be at the first regulator, but the custody transfer point could also be at the first fitting, the first isolation point, or another valve, regulator, or meter further downstream. There is no safety benefit gained by requiring gas transmission operators to treat any of the piping between the first regulator and the beginning of the LDC's piping as distribution piping.

Similarly, in the case where the entirety of the farm tap piping is owned by an LDC starting at the first fitting off of the source transmission pipeline, there is no value in requiring the gas distribution operator to treat the section of piping between the source transmission piping and the first regulator as transmission piping unless it meets the definition of transmission piping under §192.3. PHMSA's existing

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[7] *NPRM* at 35,253–54.

[8] *Id.* at 35,242 ("a portion of a farm tap between the first aboveground point where downstream piping can be isolated from source piping (e.g. a valve or regulator inlet) and either the outlet of the customer's meter or the connection to a customer's piping, whichever is further downstream, may be a service line regulated under part 192").

[9] Pipeline Safety: Farm Taps Frequently Asked Questions, 85 Fed. Reg. 21,820 (Apr. 20, 2020) [hereinafter, *Draft Farm Tap FAQs*].

regulatory requirements are rigorous for both transmission lines and distribution lines, and no additional safety benefit is derived by imposing a “one-size fits all” definition applicable to all farm taps.

Because custody transfer from transmission to distribution operators often occurs downstream of the first regulator (including scenarios where transmission operators deliver gas directly to an end user), PHMSA’s proposed guidance that gas transmission operators must treat all farm tap piping after the first regulator as service line piping would require many operators who currently only operate gas transmission pipelines to become gas distribution operators. Although a transmission operator would not be required to develop a DIMP plan in this scenario due to the option to comply with §192.740(b) instead, the operator would still be required to comply with other aspects of the distribution safety regulations and reporting requirements. For example, the transmission operator would be required to odorize the small amount of piping between the first regulator and the custody transfer point. Where farm tap piping is already being odorized downstream, installing upstream odorization adds no safety benefits and creates practical challenges associated with installing the new equipment and ensuring the correct level of odorant. As another example, if a transmission operator has replaced farm tap piping downstream of the first regulator after April 14, 2017, the operator may have installed equipment that does not meet the excess flow valve requirements because the operator treated the replaced piping as transmission, creating a potential compliance question if PHMSA now classifies all piping downstream of the first isolation point as “distribution.” In addition, a transmission operator would need to file a distribution annual report for a de minimis amount of pipe which would increase, not decrease, the regulatory burdens.

To-date, PHMSA has introduced at least four different proposals to define a uniform starting point for distribution service line piping on a farm tap, including this NPRM. However, each of these proposals elicits new concerns because different operators have defined the service line starting point differently for decades and introducing a “one-size-fits-all” solution at this point would be incredibly disruptive to operators and regulators who have developed a common understanding that works for their state. A “one-size-fits-all” solution is simply not appropriate or workable. Proposed §192.740(c)(4) is particularly concerning because PHMSA proposed an alternate approach just a few months ago. In draft Frequently Asked Questions (FAQs) published in April 2020, PHMSA proposed that “[on] a farm tap, the ‘source’ piping ends and the service line begins at the first point where the downstream service line can be isolated from the source piping . . . .”[10] In this NPRM, PHMSA has not explained why the agency now believes that service line piping on a farm tap should start at the first regulator, connection to customer-owned piping, or outlet of the meter. PHMSA’s earlier attempts to define a uniform service line starting point for farm taps also contradict the current NPRM and adds to the confusion. In FAQs published in 2018, that have since been withdrawn, PHMSA indicated that “[f]arm taps typically initiate at the fitting connecting the service line to its source of gas supply.” Earlier rulemakings took a fourth approach, suggesting that the distribution service line piping does not begin on a farm tap off of a transmission line until the custody transfer meter from the transmission operator to an LDC or customer-owned piping.[11]

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[10] *Id.* at FAQ #3. *See also* Comments of AGA, APGA, API and INGAA on Draft Farm Tap FAQs, No. PHMSA-2019-0131(June 19, 2020), https://beta.regulations.gov/document/PHMSA-2019-0131-0009.

[11] *See* Customer Owned Service Lines, 59 Fed. Reg. 5,168 (Feb. 3, 1994) (PHMSA stated that “[a] ‘farm tap’ is a customer-owned service line that begins at a customer meter, usually adjacent to a gas transmission line, and runs (often a considerable distance) to a single consumer. . . . [and] is referred to as a customer-owned service line.”) (emphasis added); Excess Flow Valve—Performance Standards, 61 Fed. Reg. 31,449 (June 20, 1996) (PHMSA stated that “[a] farm tap operates as a service line when a local distribution company operates a metered farm tap on a transmission line delivering gas to a farmer or other landowner.”) (emphasis added).

These different approaches highlight the challenges of identifying a uniform distribution service line starting point for all farm taps.

It should be noted that piping with a Maximum Allowable Operating Pressure (MAOP) greater than 20% of Specified Minimum Yield Strength (SMYS) is required to be classified as transmission under §192.3 regardless of its location on a farm tap. This renders a single, uniform service line starting point impossible due to different piping and pressure control configurations on farm taps.

For the last several years, the Associations have consistently offered a durable resolution to this long-standing issue: revise §192.3. The Associations' approach was unanimously endorsed by the GPAC in 2018.[12] Specifically, in the forthcoming "Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments" Final Rule, PHMSA should update §192.3 to (1) incorporate an appropriate distribution center definition that allows the beginning of farm tap piping to be classified as a distribution center[13] and (2) explicitly allow operators to voluntarily designate piping as transmission, even if the pipeline could be classified as distribution under existing §192.3. This approach would allow operators appropriate flexibility to establish and document a reasonable distribution service line starting point for each farm tap based on its particular configuration and other system-specific factors. This approach would also help ensure a more uniform treatment of laterals, regardless of whether a lateral is a "farm tap" or serving some other type of end user.

The Associations recommend revising §192.740(c) as follows:

§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.**~~

III. PHMSA Should Adjust the Monetary Damage Threshold Periodically for Reporting Incidents in Section 191.3

The Associations support PHMSA's proposal to update the threshold for property damage in the definition of an incident to account for inflation. The Associations also support PHMSA's proposal to

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[12] *See* GPAC Meeting Tr. 281:3–284:3 (Mar. 27, 2018), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=971.

[13] The Associations recommend the following definition for "distribution center": *Distribution center* means the initial point where gas piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale, for example: (1) at a metering location, (2) pressure reduction location, such as a gate station or custody transfer point, or (3) where there is a reduction in the volume of gas, such as a lateral off a transmission line.

establish the new threshold to reflect the calendar year when this rule is finalized.[14] 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 still be reported as an incident than would have been in 1984. This results in a distorted view of pipeline safety performance, since reportable incidents are often used as a performance metric for the natural gas industry. Additionally, 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.

The Associations also support PHMSA's proposal to update the reporting threshold every two years to account for inflation via notice on the PHMSA public website. A periodic update will provide certainty and avoid a repeat of the current situation, where the current threshold does not account for over three decades of inflation. Conducting biennial rulemakings to update the threshold seems unnecessarily burdensome for both PHMSA and stakeholders; the current NPRM provides appropriate notice and opportunity for comment on the proposed method to update the threshold. PHMSA should revise §191.3 to clarify the agency's intended process for periodically updating the threshold in its final rulemaking.

IV. <u>PHMSA Should Clarify the Physical Inspection Interval for Remotely Monitored Rectifier Stations</u>

The Associations support PHMSA explicitly allowing remote monitoring of impressed current cathodic protection sources in the pipeline safety regulations. The Associations recommend that PHMSA clarify that operators must physically inspect remotely monitored rectifiers at the cathodic protection test frequency required in §192.465(a) and that the rectifier inspection need not necessarily occur at the exact same time as the cathodic protection testing.

Although rectifier inspections may be performed in conjunction with cathodic protection testing for efficiency purposes, this will not always be the case because the tasks require different tools and may involve different personnel. Furthermore, rectifiers often influence multiple pipe segments, and the currently-proposed wording of §192.465(b)(2) could be interpreted to require a redundant physical inspection of the same rectifier every time each of the segments influenced by that rectifier is tested, or even multiple times per segment if the testing occurs over multiple days.

The Associations recommend revising §192.465(b)(2) as follows:

§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.

[14] *NPRM* at 17 ("PHMSA intends to base any finalized version of this provision on the price level at the time of publication of the final rule").

(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).

V. PHMSA Should Clarify the Atmospheric Corrosion Monitoring Intervals for Gas Distribution Service Lines which have been Remediated in Section 192.481

The Associations support PHMSA's proposal to revise §192.481 *Atmospheric corrosion control: Monitoring* to establish a separate atmospheric corrosion inspection interval for gas distribution service pipelines. Allowing operators to align leak and atmospheric corrosion inspection intervals for gas distribution services lines reduces regulatory burdens while enhancing pipeline safety. The cost savings realized by aligning these two routine inspections can be reallocated to other pipeline safety activities and asset improvement projects. The Associations, however, request PHMSA revise proposed §192.481(d) and remove the word 'evaluate' from §192.481(a). Section 192.481(d) requires operators to default to a 3-year (not to exceed 39 months) interval on distribution service pipelines if atmospheric corrosion is found. The Associations can assume that the proposed narrowing of the inspection interval for these service pipelines is intended to reflect the identification of atmospheric corrosion as a threat on the service pipeline. PHMSA also does not describe its justification for adding the requirement to evaluate to 192.481(a).

The Associations urge PHMSA not to revise the requirements in §192.481 without taking into account the existing and proposed requirements within Subpart P: *Gas Distribution Pipeline Integrity Management (IM)* otherwise known as the operator's Distribution Integrity Management Program (DIMP). Current DIMP regulations require distribution pipeline operators to "identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.[15]" Furthermore, PHMSA has proposed to explicitly reference atmospheric corrosion in §192.1007(b) where the regulation lists the threats that an operator must consider. The Associations agree with PHMSA's assessment that there is an expectation for "operators of service lines in high-corrosion environments to consider atmospheric corrosion in their evaluation of risks under DIMP and conduct atmospheric corrosion inspections more frequently than the minimum requirements in this section (§192.481)." To ensure prompt remediation of identified atmospheric corrosion, the Associations recommend a prescriptive remediation requirement in lieu of a shortened inspection cycle. By remediating through recoating or replacement, operators can continue to keep all service pipelines on a 5-year inspection cycle.

Revising proposed §192.481(d) and removing the additional evaluation requirement also eliminates a host of additional questions and needs for clarification. For example, in PHMSA's proposal, if all above ground piping on a distribution service pipeline found to have atmospheric corrosion is replaced, does that distribution service pipeline still need to be inspected after 3 years? What if other remediation activities are performed on that service pipeline—such as cleaning and coating to remove the threat of further corrosion—can that service pipeline still be inspected on a 5-year interval?

The Associations remind PHMSA of its own justification for updating §192.481: since 1986 there have been no documented distribution incidents related to atmospheric corrosion. Additionally, AGA conducted a study in 2009 which analyzes changes to the frequency of conducting atmospheric corrosions and determined that atmospheric corrosion inspections at intervals greater than 36 months

[15] 192.1007(a)(1)

show no significant change in the incidence of corrosion or gas leaks at potentially longer inspection intervals.[16] Therefore, the Associations believe PHMSA has addressed the threat of atmospheric corrosion fully through prescriptive inspections every 5 years and explicit consideration through DIMP.

The Associations offer the following redlines to the proposed §192.481.

§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	least once every 3 calendar years, but with intervals not exceeding 39 months
Onshore Service Line	least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in paragraph (d) of this section
Offshore	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 disbonded 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**~~ **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.

VI. PHMSA Should Clarify its Minimum Wall Thickness Requirements for 1-inch CTS pipe in Section 192.121

The Associations support the changes proposed to §192.281 and §192.283. These recommendations align with AGA's petition for reconsideration of the plastic pipe rule,[17] and allows operators to use alternate procedures to join polyethlene (PE) which are equivalent and/or more stringent than the heat fusion procedure detailed in ASTM F2620-12. PHMSA also proposed revising its minimal wall thickness tables for PE pipelines, (§192.121(c)(2)(iv)), polyamide 11 (PA-11) (§192.121(d)(2)(iv)), and polyamide 12

[16] https://www.aga.org/globalassets/safety--standards/aga_consolidated_atmospheric_report_oct_22_2009.pdf

[17] *NPRM* at 35,246–247.

(PA-12) (§192.121(e)(4)), to be consistent with the copper tubing size (CST) pipe in ASTM D2513, ASTM F2945, and ASTM F2785.[18]

The proposed revision to the table labeled "PE Pipe: Minimum Wall Thickness and SDR Values" (Table 1) of §192.121(c)(2)(iv) revises the wall thickness for SDR11 1-inch CTS pipe from .119 wall thickness to .101. However, gas operators typically use SDR11.5 pipe, which has a .099 wall thickness, for 1-inch CTS pipe. As proposed, the revisions in the NPRM would restrict the use of SDR11.5 pipe. For year, operators have been installing SDR11.5 pipe within their systems, which is in compliance with the current requirements within §192.121. The Associations believe that PHMSA inadvertently restricted the use of SDR11.5. This is further supported by the fact that there have been no incidents associated with the performance of SDR 11.5 pipe in distribution systems. SDR11.5 has been shown to handle pressures which make it well-suited for its use in distribution systems.

If operators were limited to using SDR11 1-inch CTS pipe, operators would need to special order new pipe and potentially be left with extra SDR11.5 1-inch CTS in their warehouses. This could also result in delays in completing safety work as well as routine maintenance projects on the natural gas pipeline systems. The Associations recommend that PHMSA revise Table 1 to show the minimum wall thickness of 0.099 for 1-inch CTS pipe. This allows operators to use SDR11 and SDR11.5 CTS and does not pose an increased risk to public safety.

The Associations offer the following redlines to the proposed §192.121.

Subpart C— PIPE DESIGN

§192.121 Design of Plastic Pipe

(c) Polyethylene (PE) pipe requirements.

…

PE PIPE—MINIMUM WALL THICKNESS AND SDR VALUES

Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
½″ CTS	0.090	7
¾″ CTS	0.090	9.7
½″ IPS	0.090	9.3
¾″ IPS	0.095	11
1″ CTS	~~0.101~~ **0.099**	11**.5**
1″ IPS	0.119	11
1¼″ IPS	0.151	11
	…	

[18] *Id.*

VII. <u>The Associations Support PHMSA's Proposal to Align Pressure Vessel Testing Requirements with the ASME BPVC and Recommend Modifications to Better Align Part 192 and the ASME BPVC</u>

The Associations support PHMSA's proposed modifications to §192.153 to align the gas pipeline pressure vessel testing regulations with the ASME BPVC test requirements. For more than a century, pressure vessels designed, constructed and tested under the ASME BPVC have been utilized in a variety of industries around the world, including: gas processing, petroleum refining, chemical and petrochemical manufacturing, power generation, military facilities, industrial boilers, pulp and paper manufacturing, food processing, aviation railroad and highways, and other manufacturers. The ASME BPVC is recognized and accepted as the standard of safety by many government agencies worldwide. In the United States, this includes the Occupational Safety and Health Administration, the Bureau of Safety and Environmental Enforcement, the Department of Energy, and the Department of Defense.

Per ASME BPVC Section VIII, Division 1, Subsection A, Part UG-100, Hydrostatic Testing, pressure vessels are tested at the facility at which they are fabricated using a pressure test. The pressure test is one of many inspection and testing provisions in Part UG-90 through UG-103. The pressure test is conducted by the manufacturer along with other key inspections under the oversight of a National Board of Boiler and Pressure Inspectors authorized inspector so that a "U" stamp can be placed on the vessel. The ASME BPVC Division 2 and Division 3 Code requirements have similar inspecting and testing provisions.

Therefore, the Associations strongly agree with PHMSA that operators should have the option to visually inspect pressure vessels for damage once the vessel has arrived at a pipeline facility, rather than perform another pressure test. It is not recommended that operators re-test pressure vessels after the manufacturer has already tested and certified the component unless absolutely necessary because re-testing will likely require the oversight of an inspector authorized by the National Board of Boiler and Pressure Inspectors. Pipeline operators do not generally have National Board of Boiler and Pressure Inspectors authorized inspectors on staff, creating a logistical and resource burden if every vessel must be re-tested onsite. Without the involvement of an authorized inspector, re-testing could potentially invalidate the vessel's National Board stamp, creating potential noncompliance with PHMSA and other agency regulations and risking the warranty and insurability of these components. Furthermore, there are no ASME BPVC requirements to re-pressure test vessels once they have arrived onsite.

The Associations also believe that PHMSA should remove the requirement to inspect vessels after "installation." For many vessels, it may be impracticable or unsafe to inspect for damage after installation. For example, gas compressor pulsation bottles are often installed amidst a multitude of piping, compressor throws, access platforms, and other equipment making post-installation access to the bottle impracticable or unsafe. When maintenance is performed on these bottles, they are often removed from their installed location. For similar reasons, in the unlikely event that an operator does elect to pressure test a vessel onsite, PHMSA should remove the requirement to test the vessel "in place." In the compressor bottle example described above, performing a hydrostatic test after the bottle had been installed in a tight location and potentially connected to piping and compressor equipment is impracticable and risks causing corrosion or other damage to downstream compression equipment because it would be difficult to completely remove the water from the system when the vessel is already installed.

Finally, PHMSA should broaden §192.153(e)(3) to apply to all pressure vessel relocations, rather than just "newly manufactured" vessels. A post-transportation visual inspection for damage is appropriate for equipment relocated from one field location to another, just like it is an appropriate safety measure for new vessels first brought to a site. In the NPRM preamble, PHMSA states that "a pressure vessel that has been used for any purpose prior to installation on a pipeline facility must be pressure tested again in place . . ." This statement fails to recognize the unique, comprehensive certification and compliance process involved in pressure vessel manufacturing and testing. As noted previously, this re-testing creates numerous challenges for pipeline operators with respect to the vessel's National Board of Boiler and Pressure Inspectors stamp. The ASME BPVC and the requirements of the National Board of Boiler and Pressure Vessel Inspectors reflect input of the world's leading experts on pressure vessels; if re-testing relocated vessels was warranted, these expert bodies would include that requirement, which they do not. Inspection, not pressure testing, is the appropriate solution to ensure that relocated vessels are fit-for-service.

Based on the above comments, the associations recommend the modifications in **red** below to proposed §192.153(e)(3):

§192.153 Components fabricated by welding

[. . .]

(3) After [Insert Effective Date of the 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 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 installation into the pipeline**~~. Inspection records for the **fabricated** 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.

VIII. PHMSA Should Extend the Allowance for Pre-tested Short Segments of Pipe and Fabricated Units to Pipelines which Operate at Less Than 100 Pounds Per Square Inch (psi)

The Associations support PHMSA's proposal to allow operators to extend the allowance for pre-testing fabricated assemblies to include steel pipelines that operate at a hoop stress less than 30 percent of SMYS and at or above 100psi. As noted in the NPRM "*this provision is currently applicable to higher-stress pipelines operating at a hoop stress greater than 30 percent of SMYS only, extending the broader pre-testing provision to lower-stress pipelines would not increase safety risks. This proposed change will provide greater flexibility and efficiency for operators of lower-stress pipelines, especially during maintenance activities.*"[19]

Similarly, the Associations urge PHMSA to consider the inclusion of other pipelines which also pose less of a safety risk. Specifically, the Associations recommend that PHMSA extend the allowance for pre-tested short segments of pipe and fabricated units to pipelines that operate at pressures less than 100psi (§192.509). Furthermore, the Associations recommend that PHMSA clarify this allowance extends to short segments or prefabricated units installed on services and plastic pipelines (§192.511 and §192.513). This provides clarity and consistency within the regulations. In 2019 alone, distribution system operators reported 84,608 excavation damages on their DOT Distribution Annual Reports. Assuming $ 200 per post-installation pressure test, the cost is nearly $17 million annually just to

[19] *NPRM* at 35,248–249.

pressure test pipe replaced due to excavation damage. The use of pre-tested pipe would significantly reduce these costs as operators could pretest full joints or coils of pipe for use on multiple short segment replacements and repairs without compromising safety.

To avoid confusion, the Associations also recommend that PHMSA remove the hydrostatic test requirements for short segments of pipe and pre-fabricated units from §192.507 since natural gas, inert gas, and air are also allowable test media for pipelines operating at a hoop stress less than 30% of SMYS under §192.503(c).

The Associations offer the following redlines to the proposed §192.507, §192.509, §192.511 and §192.513:

§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.

§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.

§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.

§192.513 Test requirements for service lines.

[. . .]

(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.

Respectfully Submitted,
Date: August 10, 2020

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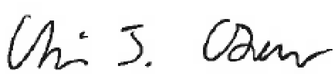

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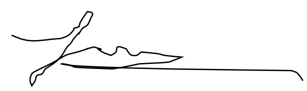

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