**BEFORE THE**
**UNITED STATES DEPARTMENT OF TRANSPORTATION**
**WASHINGTON, D.C.**

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| Notice of Review of Guidance | Docket No. DOT–OST–2017–0069 |

**RESPONSE TO NOTICE OF REVIEW OF GUIDANCE**

**FILED BY**
**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 Department of Transportation concerning the "Notice of Review of Guidance." These comments pertain to guidance issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) and are limited to PHMSA's regulations governing natural gas pipeline and storage facilities.[5]

Pipeline safety is the top priority of the Associations and their members. The Associations strongly support regulations and guidance materials that advance improvements in pipeline safety practices and that embrace modern integrity assessment processes and technologies, with the intent of achieving a perfect safety and reliability record for our nation's natural gas pipeline and storage network. The Associations commend the Department of Transportation for taking steps to reevaluate existing guidance documents "to reflect developments, such as technological changes, that took place after the guidance was issued."[6] In recent decades, there have been dramatic engineering and technological advances which may warrant changes to past guidance.

The Associations believe that the recommendations outlined below will support PHMSA in its objective to promulgate pipeline safety and storage regulations that are "straightforward, clear, and designed to minimize burdens."[7] The reevaluation of certain PHMSA guidance that is recommended by the Associations will enable operators to reallocate resources to activities and programs that would benefit system integrity and public safety, including activities that may be required by pending new regulations.

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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 73 million residential, commercial and industrial natural gas customers in the U.S., of which 95 percent — over 69 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 28 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] PHMSA's regulations covering natural gas pipelines and underground natural gas storage facilities can be found at 49 C.F.R. Parts 191 & 192. The Associations did not review the hazardous liquid pipeline regulations as part of these comments.

[6] Notice of Review of Guidance, 82 Fed. Reg. 1,820 (Feb. 5, 2019).

[7] Notification of Regulatory Review, 82 Fed. Reg. 45,750, 45,757 (Oct. 2, 2017).

## II. General Recommendations Regarding PHMSA Guidance

PHMSA's pipeline safety and storage regulations are the basis for pipeline safety regulatory compliance. Inevitably, some degree of discretion is left to regulated entities in interpreting the regulatory requirements and actually putting those requirements into practice. As questions of regulatory intent arise, PHMSA relies upon numerous tools to provide guidance. Those tools include: frequently asked questions, guidance for PHMSA and state inspectors within inspection forms, enforcement guidance, advisory bulletins, PHMSA responses to requests for interpretations, and other general guidance documents. For each of these types of guidance, PHMSA often does not publish draft versions for public comment before finalizing the guidance materials. The Associations believe that it is always PHMSA's intent to use guidance documents to aid stakeholders in understanding the regulations. However, guidance documents often appear to create new requirements or broaden the application of existing requirements. Such is the case for several of the guidance items outlined in the comments that follow.

The Associations recognize that guidance is often needed in a timely manner, and therefore hesitate to suggest that a public comment period is always necessary before finalizing each and every guidance document. However, the Associations do appreciate the opportunity for review and comment, where appropriate. At a minimum, the Associations believe it is prudent that PHMSA publicly announce when a new or modified version of guidance, in any form, is published – regardless of the intended stakeholder audience. For example, when inspection guidance is modified, all stakeholders, not just state and federal regulators, should be made aware.

## III. Recommendations Regarding Guidance Documents Affecting Gas Transmission Pipelines

### A. PHMSA should review its policy of applying certain design and construction requirements to pipeline repair and replacement projects

The Associations request that PHMSA[8] review its current policy of applying certain design and construction requirements to replacement projects conducted for operations and maintenance reasons (O&M replacements). Through two enforcement orders[9] and two interpretations[10], PHMSA has stated that if an operator replaces a section of pipe, no matter how small, the new section must comply with the current design and construction requirements for new pipelines. This policy can detrimentally affect pipeline safety and produce unnecessary compliance costs, particularly when the depth-of-cover and valve spacing requirements are applied to short, O&M replacements. It is neither practical nor necessary for PHMSA to treat a 10-foot remediation project the same as a 10-mile replacement project.

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[8] For ease of reference, the Associations refer to the Pipeline and Hazardous Materials Safety Administration, and its predecessor agencies, the Research and Special Programs Administration, the Materials Transportation Bureau and all other federal agencies that administered the federal pipeline safety laws, collectively, as PHMSA or the Agency.

[9] *In the Matter of Viking Gas Transmission*, CPF No. 32102, Final Order (Apr. 27, 1998); *In the Matter of Williams Northwest Pipeline, LLC,* CPF No. 5-2014-1002, Final Order (December 29, 2015).

[10] PHMSA Letter of Interpretation to Eddie Abeyta, New Mexico State Corporation Comm., PI-79-037 (Oct. 24, 1979). PHMSA Letter of Interpretation to Marjorie Brant, Columbia Distribution Co., dated April 5, 1993.

PHMSA should consider revised guidance and/or alternative requirements for depth of cover and valve spacing for O&M replacements, instead of continuing to enforce a blanket policy that requires all replacements to comply with the design and construction requirements for new pipelines. PHSMA should convene a meeting of the Gas Pipeline Advisory Committee to facilitate a public discussion of these topics and receive input from stakeholders.

*Background*

Operators frequently replace short sections of existing pipe to remediate potentially injurious conditions found to be affecting that short section of pipe, to conduct pressure tests, or because other O&M regulations in 49 C.F.R. Part 192 require pipe replacement.[11] These O&M replacements are not "pipe replacement projects" in the traditional sense – only small sections of pipe are being modified. Operators generally do not re-design the pipeline when conducting O&M work.

Because of the differences in objectives between pipeline maintenance and new construction, PHMSA is prohibited by statute from applying new pipeline design and construction requirements to existing pipe.[12] The Pipeline Safety Act provides that "[a] design, installation, construction, initial inspection, or initial testing standard does not apply to a pipeline facility existing when the standard is adopted."[13] PHMSA codified this prohibition by regulation in 49 C.F.R. § 192.13(b) more than four decades ago.[14] The regulation currently provides that "[n]o person may operate a segment of pipeline that . . . is replaced, relocated, or otherwise changed after [certain historical dates] . . ., unless that replacement, relocation, or change has been made in accordance with this part."[15] The applicable historical date for most pipelines is November 12, 1970.

PHMSA adopted § 192.13(b) in the Final Rule that created the original federal gas pipeline safety regulations. Unlike many other regulations, which were included in a series of notices of proposed rulemaking that PHMSA issued following the passage of the Natural Gas Pipeline Safety Act of 1968, section 192.13(b) did not appear until the Final Rule. As a result, the rulemaking history does not include public comment or discussion about the meaning and use of the words "replacement," "relocation," or "change" in the regulation.[16] Nor did the Agency attempt to define these terms or provide any additional clarification.[17] PHMSA's explanation in the preamble was limited to two

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[11] *See, e.g.,* 49 C.F.R. §192.611. Due to commercial restrictions, replacement is often the only viable option allowed under existing regulations when a class location changes.

[12] Natural Gas Pipeline Safety Act of 1968, Pub. L. No. 90-481, 82 Stat. 720, 721 (1968)(codified as 49 U.S.C. § 60104(b)).

[13] *Id.*

[14] Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standards, 35 Fed. Reg. 13,248, 13,251 (Aug. 19, 1970).

[15] 192.13(b).

[16] 35 Fed. Reg. at 13,259.

[17] In 2006, as part of the Gas Gathering Line Definition Final Rule, PHMSA stated in the preamble that ''otherwise changed'' refers to "a substantial physical alteration of a pipeline facility as opposed to a repair or restoration." *See* Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 Fed. Reg. 13,298 (Mar. 15, 2006). However, to date, the Agency has not defined this term, replacement or relocation in the federal regulations.

statements. The Agency characterized the new regulation as needed to "…clearly state the applicability of these regulations with respect to new and existing pipelines, and to avoid confusion as to the retroactive effect of these standards."[18] The Agency also stated that "[w]ith respect to existing pipelines, all changes made after November 12, 1970, must comply with Part 192."[19] The Agency did not discuss the length of the pipe that constituted a "replacement" or the impacts of applying various construction, design, or testing requirements to short, O&M pipe replacements.

Concerns over whether PHMSA's design and construction regulations should apply to short, O&M pipe replacements arose shortly after the codification of § 192.13(b). In 1971, only one year after the adoption of § 192.13(b), the members of the Technical Pipeline Safety Standards Committee (the Committee) expressed concern with the application of § 192.13(b) in the context of short replacements of cast iron pipe. The Committee members stated that, according to a strict reading of the regulations, operators of cast iron pipelines would need to use steel for any replacement and the joining of steel and cast iron would accelerate corrosion risks.[20] The Committee members stated that without an exception from § 192.13(b) for cast iron replacements, operators would be discouraged from replacing pipe.[21] The Agency's counsel at the time confirmed that this was an issue and stated that "[w]e can put in something like 'other than short sections of replacement pipe that are installed' or something to make clear that this does not apply to replacement pipe."[22] Counsel also stated that "[w]e will have to make clear in the regulations what we mean by new installation and by replacement.[23] We realize there is a problem."[24] There is no indication that PHMSA took further action to address O&M replacements after these initial discussions in 1971.

In the decades since the introduction of § 192.13(b), the Agency has issued only two interpretations on this regulation but neither have discussed the scope of a "replacement" or the practical concerns with applying current design and construction regulations to a small section of pipe.[25]

The enforcement history for section 192.13(b) shows that PHMSA has issued only two enforcement orders involving pipe replacements. In 1998, almost three decades after the adoption of the regulation,

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[18] 35 Fed. Reg. at 13,251.

[19] *Id.* (emphasis added).

[20] In the Matter of the Technical Pipeline Safety Standards Committee, Transcript, (April 13, 1971) at 98-99.

[21] *Id.*

[22] *Id.* at 110.

[23] *Id.* at 115.

[24] *Id.*

[25] PHMSA Letter of Interpretation to Eddie Abeyta, New Mexico State Corporation Comm., PI-79-037 (Oct. 24, 1979). In 1979, PHMSA issued a letter of interpretation stating that the "purpose of section 192.13(b) is to make the design and construction requirements of Part 192 apply to segments of existing pipelines (as of November 12, 1970) that are subsequently replaced, relocated, or otherwise changed. The Agency further explained that "the portion of a service line that was replaced constitutes 'a segment of pipeline' within the meaning of section 192.13(b) and the definition of 'pipeline' under section 192.3). PHMSA Letter of Interpretation to Marjorie Brant, Columbia Gas Distribution Co. In 1993, PHMSA issued a Letter of Interpretation to Marjorie Brant of Columbia. The letter stated that any equipment added to a regulator station would need to comply with Part 192. This letter is no longer available in PHMSA's database of interpretations and therefore it is not clear if the Agency has rescinded this interpretation.

PHMSA issued an enforcement case applying the design and construction requirements to a pipe replacement.[26] In that case, the Agency found that the operator failed to comply with § 192.13(b) and the valve spacing requirement in the design code, § 192.179, in replacing 2000 feet of pipe.[27] Notably, this replacement was made pursuant to the Operations section of Part 192.[28] In 2014, PHMSA issued another enforcement case determining that an operator did not add a valve to maintain the spacing required after a pipe replacement.[29]

In August 2018, the Agency issued a Notice of Probable Violation alleging that an operator should have applied construction level cover to 348 feet of pipe that it had replaced to remediate anomalies identified by in-line inspection.[30] Notably, the 348 feet was broken up into 11 different replacement segments, some as short as ten (10) feet in length.[31] Replacing short segments of pipe to enhance pipeline integrity following in-line inspection is a prime example of an O&M replacement.

PHMSA has not otherwise issued guidance or clarification on applying the design and construction requirements to short, O&M replacements.

*PHMSA's application of design and construction regulations to O&M replacements has been inconsistent*

Looking beyond natural gas transmission pipelines, PHSMA's application of design and construction requirements to O&M replacements has been inconsistent. In 2002, PHMSA issued an interpretation to the Public Utilities Commission of Ohio (PUCO).[32] As part of its request to understand the Operator Qualification requirements, PUCO had asked the Agency whether the replacement of the entire length of a failed customer-owned portion of a service line was considered an O&M task or new construction. In its response, PHMSA stated the following:

"The replacement of a service line with new pipe, whether by insertion or direct burial, is an operations and maintenance [O&M] activity …. <u>It is not new construction because it is designed to maintain the serviceability of an existing service line</u>."[33]

This interpretation exemplifies that there is not a bright line differentiating "repairs" from "replacements" of short pipe segments. If replacing a failed service line is not considered new construction, it is questionable why any in-kind replacement to remediate integrity concerns or to comply with PHMSA's O&M regulations on a natural gas transmission line would be considered new construction. It is also difficult to reconcile this interpretation with the Agency's response in 1979 that

[26] *In the Matter of Viking Gas Transmission*, CPF No. 32102 (Apr. 27, 1998).

[27] *Id.* at 10.

[28] *Id.* at 1.

[29] *In the Matter of Williams Northwest Pipeline, LLC,* CPF No. 5-2014-1002 (December 29, 2015).

[30] *In the Matter of Dominion Energy Transmission, Inc.,* CPF No. 1-2018-1007, Notice (Aug. 8, 2018).

[31] *Id.* at 2.

[32] PHMSA Letter of Interpretation, PI-02-0101 (Sept. 18, 2002).

[33] *Id.* (emphasis added).

the portion of the service line that is replaced would need to comply with the construction requirements of the code.[34]

Finally, PHMSA has taken a different approach in Part 193, which applies to LNG facilities. The Agency stated that an operator can make an in-kind replacement of an existing LNG facility without complying with the siting design requirements.[35] PHMSA also allows for an impracticability exception if the replaced facility would be incompatible with the original specifications for the facility.[36]

PHMSA should review its policy for O&M replacements under Part 192 with these exceptions in mind.

*Treating O&M replacements as new construction raises safety concerns and is a poor use of resources*

PHMSA should reevaluate the impacts of applying valve spacing and depth of cover requirements to O&M pipe replacements. Both depth of cover and valve spacing are design and construction requirements. Natural gas transmission operators evaluate their operating systems on an ongoing basis to identify opportunities to reduce risk. Operators make short pipe replacements when their risk evaluation indicates that a short replacement is warranted to reduce risk, or to comply with PHMSA's O&M regulations. In some cases, O&M pipe replacements must be conducted immediately. The operator cannot delay remediation of a potentially injurious condition because it is waiting on a long-lead valve to arrive or because it needs to change the entire segment's depth of cover. PHMSA should not require operators to re-design a pipeline segment simply because of an O&M replacement.

<u>Valve Spacing</u>

PHMSA introduced valve spacing requirements as part of the first federal pipeline safety regulations in 1970.[37] Section 192.179(a) provides that an operator must add sectionalizing block valves on each transmission line based on the class location of the pipe. The more populated the area around the pipeline, the closer the valves.

As noted above, PHMSA issued an enforcement order to Viking Gas Transmission in 1998 interpreting that operators must apply the valve spacing requirements to O&M pipe replacements. In 2014, PHMSA issued another enforcement case relevant to valve spacing. The Agency alleged that Williams Northwest Pipeline, LLC did not add a valve to maintain the spacing required for a Class 3 location after a pipe replacement.[38]

PHMSA did not assess whether safety would be improved by adding additional valves to a short, O&M replacement section in either of these cases. Nor did PHMSA consider the costs of applying the design requirements to short replacements of pipe. Indeed, there is no indication that PHMSA has ever

[34] PHMSA Letter of Interpretation to Eddie Abeyta, New Mexico State Corporation Comm., PI-79-037 (Oct. 24, 1979).

[35] PHMSA Letter of Interpretation to William Cope, Southern LNG Co., LLC (Dec. 22, 2011).

[36] 49 C.F.R. § 193.2005(b)(2).

[37] Establishment of Minimum Standards, 35 Fed. Reg. 13,248 (August 19, 1970).

[38] *In the Matter of Williams Northwest Pipeline, LLC,* CPF No. 5-2014-1002, Final Order (Dec. 29, 2015).

analyzed the benefits or costs of applying the design and construction requirements to all pipe replacements.

It many cases, installing new valves on existing pipelines provides limited safety benefit. Valves may help mitigate some effects of a natural gas transmission pipeline incident, but they do not prevent the incident. When studying opportunities to improve pipeline incident response time, the Government Accountability Office (GAO) noted that "PHMSA has an opportunity to improve the ability of pipeline operators to respond to incidents by developing a *performance-based* approach for incident response times."[39] Furthermore, GAO noted that "[b]ecause the advantages and disadvantages of installing an automated valve are closely related to the specifics of the valve's location, it is appropriate to decide whether to install automated valves on a case-by-case basis."[40] Although this particular statement references automated valves, the logic applies to both manual and automated valves. Similarly, Oak Ridge National Labs has studied this issue extensively and concluded that "without fire fighter intervention, the swiftness of block valve closure has no effect on mitigating potential fire damage to buildings and personal property in Class 1, Class 2, Class 3, and Class 4 HCAs resulting from natural gas pipeline releases."[41] Finally, the American Society of Mechanical Engineers has studied the safety impacts of valve spacing, and concluded that "valves are useful for maintenance and line modification but they do not control or affect public safety" because they "have no impact on the likelihood of a failure and only a small reduction in the consequences of a failure on a natural gas transmission pipeline."[42] Thus, in many cases, an unqualified requirement to install new block valves on all short, O&M replacements would not reduce risk.

Estimated costs to install new block valves on an existing pipeline are included in Table 1 below. The Associations estimate that thousands of short, remedial replacements have occurred on pipelines that were installed prior to the implementation of PHMSA's valve spacing requirements in 1970. The Associations expect similar O&M replacements to continue in the future on pre-1970 lines. Thus, an unqualified requirement to consider valve spacing for every pipe replacement, regardless of length, would cost hundreds of millions of dollars.

**Table 1: Estimated costs to install valves on existing gas transmission pipelines[43]**

| Valve Size (NPS) | Installation Cost per Valve |
|---|---|
| 24" | $600,000 |
| 30" | $700,000 |
| 36" | $800,000 |

[39] U.S. Government Accountability Office, Better Data and Guidance Needed to Improve Pipeline Operator Incident Response, GAO 13-168 (Jan. 23, 2013).

[40] *Id.* at 2.

[41] Oak Ridge National Labs, Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety (Oct. 31, 2012).

[42] Eiber, Robert and Kiefner and Associates, Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing, ASME Standards Technology, LLC (Jul. 2010).

[43] Source: operator survey representing approximately 145,000 miles of natural gas transmission pipeline operators

A holistic approach to pipeline risk management would be more effective in promoting pipeline safety. Instead of focusing specifically on valve spacing, a pipeline company could allocate these resources towards more effective pipeline safety management practices, such as integrity assessment programs. Integrity assessment programs identify and prevent the mechanisms that lead to pipeline degradation, thus preventing leaks from ever occurring. By comparison, an operator could assess approximately 6,000 miles with in-line inspection[44] or excavate and remediate approximately 1,000 anomalies[45], instead of installing 100 30" block valves.

The Associations request that PHMSA review its position on valve spacing requirements for O&M pipe replacements and engage with stakeholders on this issue during the upcoming "Amendments to Parts 192 and 195 to require Valve installation and Minimum Rupture Detection Standards" Notice of Proposed Rulemaking.[46] Although PHMSA could address this issue through additional guidance, the upcoming rulemaking offers a better opportunity to provide clear and durable direction to operators. There are a variety of reasonable, risk-informed approaches that PHMSA could employ to clarify when a pipe replacement must comply with the design and construction requirements for valve spacing. For example, PHMSA could consider revising the scope of § 192.179 such that it only applies to replacement projects where the majority of the pipe between two existing block valves is replaced. Also, PHMSA could allow operators to employ the new valve automation requirements on existing pipelines where a replacement has occurred, in lieu of installing additional valves. The Gas Pipeline Advisory Committee is an appropriate forum to consider these and other alternatives.

Depth of Cover

When constructing a pipeline, PHMSA requires operators to add certain levels of 'cover' or burial depth depending on the location of the pipeline.[47] After initial construction, the cover can naturally recede due to erosion. PHMSA has acknowledged that operators do not need to maintain the original depth of cover for the life of the pipeline unless the reduced cover could impact the safety of the pipeline.[48] The Agency has also stated that "there is not any evidence to support the proposition that maintaining original cover would be cost-effective as a general safety rule."[49] In addition, the class location around an existing pipeline may change. Nothing in the class location change regulations (§§ 192.609 and 192.611) requires the pipeline to meet the design and construction requirements for the new class

[44] Although in-line inspection costs will vary substantially based on the type of tool and other operational factors, data from the Associations' member survey indicates an average cost of $10,000 per mile for in-line inspection.
[45] Although the costs of an anomaly evaluation dig will vary substantially based on the specific circumstances of the excavation, data from the Associations' member survey indicates an average cost of $62,500 to conduct an anomaly evaluation dig.
[46] Amendments to Parts 192 and 195 to require Valve installation and Minimum Rupture Detection Standards, RIN 2137-AF06.
[47] 49 C.F.R. § 192.327. The required cover levels for new construction can vary between 18-36 inches depending on the location of the pipeline.
[48] PHMSA Letter of Interpretation to Arthur Gnann, North Carolina Natural Gas Corp., PI-77-03 ( Jan. 27, 1977); *See also,* PHMSA Letter of Interpretation to the Honorable Thomas A. Luken, House of Representatives, PI-84-0103 (Aug. 6, 1984) at 1.
[49] PHMSA Letter of Interpretation to the Honorable Thomas A. Luken, at 2.

location, provided that the pipeline maximum allowable operating pressure (MAOP) meets the requirements of § 192.611.

However, on August 6, 2018, the Agency brought an enforcement action alleging that an operator should have added new construction depths of cover to 348 feet of O&M pipe replacements. The fact pattern in this case is not unique. Similar to many pipelines, the operator, in the interest of safety, voluntarily replaced certain short sections of existing pipe ranging from 10 to 40 feet in length as part of its ongoing assessment of the pipeline and repair of anomalies. PHMSA stated that the operator should have used 36 inches of cover for the short sections of replacement pipe while a lesser depth of cover is acceptable for the remaining pipeline.

PHMSA's apparently new position in this recent case creates adverse safety impacts and a disincentive for elective pipeline assessments and repairs. The only options to significantly increase depths of cover for small sections of replaced pipe are to (1) lower a substantial section of pipeline, exposing the line to strain and low spots where liquids could collect and present a corrosion risk, (2) install elbows or bends to lower the replaced pipe, which would again subject the small sections to liquid buildup and may make the pipeline segment incapable of assessment with in-line inspection, or (3) provide additional cover for the replaced sections, which would result in irregular mounds of soil along the right-of-way and potentially lead to disputes with landowners. Moreover, depending on the location of the right-of-way, operators may face access and environmental permitting issues in order to add additional cover. None of these are safe and practical solutions.

On account of the anticipated changes to the Part 192 regulations,[50] the Associations expect that operators will be expanding the use of integrity assessment programs and conducting even more assessments and O&M pipe replacements, to remediate anomalies, in the future. All stakeholders agree that these programs are among the most effective means to ensure pipeline safety. However, requiring all projects, no matter how small, to comply with the depth-of-cover requirements applicable to new pipe construction will likely increase cost and regulatory complexity and may reduce an operator's incentive or ability to complete voluntary assessments and remediations.

A variety of other requirements and improvements to Part 192 ensure safety when a pipeline's depth of cover changes over time. For example, PHMSA requires operators to conduct patrols (§ 192.705) and install pipeline markers (§ 192.707). An operator must also comply with damage prevention programs (§192.614), state One Call requirements, and public awareness programs (§192.616). If the depth of cover becomes unsafe, then the operator must rectify the situation (§ 192.703(b)). Furthermore, operators have implemented voluntary practices to help mitigate the risk of excavation damage, including providing operator personnel to observe ongoing excavations[51] and applying soft excavation techniques within the tolerance zone of the line locate.[52]

PHMSA has taken a different approach for hazardous liquid pipelines, allowing an exception from new construction depth of cover requirements if it is impracticable to comply with the minimum

[50] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722 (Apr. 8, 2016).

[51] Common Ground Alliance, Best Practices, 5.33 (Mar. 2018).

[52] *Id.* at 5.20.

requirements.[53] In those situations, the Agency allows an operator to apply protection that is "equivalent to the minimum required cover."[54]

The Associations request that PHMSA convene a stakeholder workshop to review the implications of requiring new construction depths of cover for short, remedial replacements and consider issuing revised guidance and/or alternative requirements to maintain the safety of the pipeline without requiring an operator to lower a pipeline, add bends, or disrupt the right-of-way. This could be accomplished during a meeting of the PHMSA Gas Pipeline Advisory Committee.

*Going Forward*

The Associations request that PHMSA reevaluate its prior guidance that applied design and construction requirements to O&M replacements and consider revised guidance and/or alternative requirements, where appropriate. PHMSA's current approach often results in increased costs and unnecessary regulatory burdens, which may reduce the incentive for operators to voluntarily perform pipeline integrity assessments and O&M replacements. PHMSA's current approach provides minimal safety benefits at a high cost. It is common sense that operators must be able to remediate anomaly locations without changing the entire pipeline's depth of cover or installing additional valves.

The Associations suggest that the upcoming automated valve rule and associated Gas Pipeline Advisory Committee meetings present an important opportunity to receive stakeholder feedback on valve spacing issues. Similarly, a Gas Pipeline Advisory Committee meeting can serve as a public forum to discuss the depth of cover issues. Going forward, PHMSA should solicit input from the Gas Pipeline Advisory Committee before using guidance to apply any other design and construction requirements to O&M activities.

**B. PHMSA should clarify its enforcement guidance for the inspection and testing of voluntarily-installed relief devices**

PHMSA should revise its recently issued interpretation (PI-18-0010) on the inspection of secondary relief devices and amend its enforcement guidance to clarify that 49 C.F.R. §§ 192.731, 192.739, and 192.743 only require operators to inspect and test primary relief devices. If an operator's own risk management program identifies the opportunity to reduce risk by installing secondary relief devices, then the operator's risk management program and procedures should dictate an appropriate testing frequency. PHMSA should not disincentivize the voluntary installation of safety devices by requiring annual inspection and testing, which is an overly-burdensome and unnecessarily prescriptive frequency for devices that are redundant by nature.

*PHMSA's guidance is inconsistent regarding the inspection and testing of voluntarily-installed relief devices*

Operators install relief devices to meet the requirements of 49 C.F.R. §§ 192.169, 192.195 and 192.201. These code-required relief devices are "primary" relief devices. However, an operator may also choose

[53] 49 C.F.R. 195.248(b)(1). *See also* 192.327(c).

[54] *Id.*

to voluntarily install "secondary" relief devices to meet other safety or operational objectives, beyond PHMSA's regulatory requirements.

PHMSA requires pipeline operators to inspect and test natural gas pressure relieving, regulating, and limiting devices once each calendar year at intervals not exceeding 15 months.[55] PHMSA does not define "pressure relieving device," "pressure limiting station," or "pressure regulating station" in its regulations, therefore the scope and application of §§ 192.731, 192.739, and 192.743 is somewhat unclear. At various points in time, PHMSA has stated in interpretations and enforcement orders that these testing and inspection requirements apply (1) to all relief devices,[56] (2) only those involved in the transportation of gas,[57] and (3) only primary devices.[58] The conflicting interpretations and enforcement orders cause uncertainty in what actions an operator must take to stay in compliance.

Of particular importance, in a 2010 enforcement order, PHMSA clearly stated that voluntarily-installed secondary relief devices are not required to comply with § 192.739.[59] In a subsequent Decision on Petition for Reconsideration in the same matter, the Agency explicitly clarified that the annual inspection and testing requirements do not apply to "devices that are not otherwise required to be installed on the pipeline facility for overpressure protection. For example, if an operator has a relief valve of requisite capacity to protect the pipeline facility in case of a failure of pressure control…PHMSA does not intend to enforce § 192.739 against additional relief valves the operator chooses to install on the facility…"[60] PHMSA also confirmed that the operator's relief valves were not subject to inspection and testing where there was "other means of protection, such as a second 'monitor' regulator, pilot-operated shutoff valve, or high pressure shutdown switch."[61]

After PHMSA provided this clear guidance in 2010 and 2011, the Associations' members considered the matter to be settled. Unfortunately, PHMSA issued a completely contradictory letter of interpretation in October 2018, stating that "all relief devices…must be installed, maintained and inspected in accordance with the applicable paragraphs of §§ 192.201, 192.731, 192.739, and 192.743."[62] PHMSA's 2018 interpretation letter did not acknowledge the existence of the precedents set in 2010 and 2011 and therefore has created confusion across the industry regarding whether voluntarily-installed, secondary devices must now be inspected annually.

[55] 49 C.F.R. §§ 192.731, 192.739, and 192.743.

[56] PHMSA Letter of Interpretation to Chief, Central Region, PI-76-066 (Oct. 4, 1976); PHMSA Letter of Interpretation to Mahendra Jhala , California Public Utilities Comm., PI-99-0100 (Feb. 8, 1999).

[57] *See* PHMSA Letter of Interpretation to Charles H. Kent (Panhandle Eastern Pipeline Co.), PI-77-005, (Jan. 28, 1977); PHMSA Letter of Interpretation to Kathleen O'Leary, Columbia Gulf Transmission Co., PI-79-018 (Jun. 1, 1979).

[58] *In the Matter of Dominion Transmission, Inc.* CPF No. 1-2009-1006, Final Order, (December 30, 2010). PHMSA acknowledged that a fuel gas bypass relief valve, personally operated by company employees, is a secondary form of protection, and therefore is not covered by the testing and inspection requirements of § 192.739.

[59] *Id.*

[60] *In the Matter of Dominion Transmission, Inc.* CPF No. 1-2009-1006, Decision on Petition (October 13, 2011).

[61] *Id.*

[62] PHMSA Letter of Interpretation to David J. Chislea, Michigan Public Service Commission, PI-18-0010 (Oct. 4, 2018)

*Implementation of PHMSA's 2018 guidance on the inspection and testing of voluntarily-installed relief devices may decrease safety and increase operator costs*

PHMSA's policy change in 2018 may negatively impact safety. PHMSA's 2018 interpretation may deter companies from voluntarily installing new secondary devices and may encourage operators with existing secondary devices to remove them. For those operators who choose to maintain secondary relief devices on a voluntary basis, PHMSA's new interpretation would needlessly increase the cost of retaining that existing equipment. The Associations estimate that there are thousands, if not tens of thousands, of voluntarily-installed, secondary relief devices operating on pipeline systems today. Thus, PHMSA's 2018 policy change could add substantial annual costs, without demonstrable safety improvements.

*Going forward*

PHMSA should revise its 2018 letter of interpretation and issue guidance confirming that operators can establish and document their own schedule for inspecting and testing voluntarily-installed, secondary relief devices, based on the operator's own risk evaluation and O&M procedures. There is precedent for allowing the inspection of relief devices on intervals other than one year. For example, § 192.740 allows testing every three years for relief devices installed on individual service lines directly connected to production, gathering, or transmission pipelines.[63]

### C. PHMSA should make inspection protocols and Inspection Assistant "considerations" available in advance of integrated inspections.

PHMSA should provide inspection protocol questions in advance of all inspections. PHMSA should also publish the "considerations" contained within its Inspection Assistant program.

*PHMSA should provide inspection protocol questions in advance of all inspections*

In recent years, PHMSA began providing inspection protocol questions in advance of its integrated inspections. Providing these questions in advance dramatically improves the effectiveness and efficiency of the inspections, both for operators and for PHMSA inspectors. Unfortunately, this guidance is not provided consistently. PHMSA should provide inspection protocol questions in advance of all inspections.

By providing protocol questions in advance, operators are able to ensure that the right personnel are available, identify which procedures and records that the PHMSA inspector will want to review, and obtain records that may not be physically located at the inspection location. This information collection will ultimately be required during the actual inspection anyway, so there is no additional information collection burden in allowing operators to get the work done in advance.

The Associations believe that both operators and PHMSA view the inspection process as an opportunity to identify any critical compliance gaps that should be remedied in order to improve pipeline safety. Providing inspection protocol questions in advance helps inspectors get to these core issues more quickly during an inspection.

[63] 49 C.F.R. § 192.740.

*PHMSA should publish the "considerations" contained within its Inspection Assistant program*

PHMSA should also publish the "considerations" that are listed within the PHMSA "Inspection Assistant" program. The Associations' members have observed that inspectors interpret these considerations in significantly different ways. Making the Inspection Assistant considerations available to operators will facilitate a common understanding of the inspection protocols and help promote consistency across different PHMSA regions and inspectors.

*Going forward*

PHMSA should provide inspection protocol questions in advance of all inspections and publish the "considerations" contained within its Inspection Assistant program. PHMSA should continue to look for such opportunities to improve the efficiency of the inspection process.[64]

## IV. <u>Recommendations Regarding Guidance Documents Affecting Gas Distribution Pipelines</u>

### A. PHMSA should ensure alignment between the Distribution Integrity Management Inspection Forms and regulatory requirements

PHMSA should amend the inspection and enforcement guidance within Form 24 for Gas Distribution Integrity Management – Knowledge of the System to align the examples provided to inspectors with the expectations in the regulation, § 192.1007(a)(5).

*The guidance provided to PHMSA's state partners for Distribution Integrity Management Program (DIMP) inspections is inconsistent with the regulation language.*

PHMSA's Form 24: *Distribution Integrity Management Program (GDIM) Implementation Inspection Form* asks distribution operators if "required data on any new pipeline installations since August 2, 2011" has been captured. The guidance provided to inspectors lists examples of the types of pipeline attribute data that should be captured by the operator, "e.g. location, wall thickness / SDR, manufacturer, lot/production number." However, the regulatory language within § 192.1007(a)(5) requires operators to "provide for the capture and retention of data on any new pipeline installed. The data must include at a minimum, the location where the new pipeline is installed and the material of which it is constructed."

The guidance PHMSA provides to state pipeline safety inspectors in Form 24 expands the pipeline attributes operators are expected to capture for new pipelines. The regulation specifically only lists the location and material of the pipeline, while the inspection guidance includes wall thickness / SDR, manufacturer, and lot/production number. While the Associations recognize collection of these additional attributes is important, their omission does not warrant a code violation. However, because they are included in the inspection form, operators and state regulators often find themselves disagreeing on what the regulation requires.

Interestingly, this discrepancy has been addressed in PHMSA's new Gas Distribution Integrated Assessment Question Set, but not on the inspection guidance utilized by state partners. The question in the PHMSA Gas Distribution IA Question Set simply states "System Knowledge – New Pipe Data – Do the procedures require the capture and retention of data on any new pipeline installed?"

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[64] The duration of inspections is increasing. For example, one recent gas transmission pipeline inspection lasted over two years.

*Going Forward*

PHMSA should revise Form 24 to align with the requirements within § 192.1007(a)(5) and to match their IA Question Set.

Respectfully submitted,
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