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Washington, DC 20590-0001

Re: Docket ID: PHMSA-2017-0151, Pipeline Safety: Class Location Change Requirements

On July 31, 2018, the Pipeline and Hazardous Materials Safety Administration (PHMSA or the Agency) published an advance notice of proposed rulemaking (ANPRM) asking for public comment on potential amendments to the class location regulations for gas pipeline facilities in 49 C.F.R. Part 192.[1] Specifically, PHMSA asked whether it should modify the requirements that apply to population-based class location changes that occur after a pipeline is constructed and placed into service.[2] The current regulations generally require operators to respond to class location changes by (1) reducing maximum allowable operating pressure (MAOP), (2) conducting a new pressure test, or (3) replacing the pipe.[3] The pipeline industry has urged the Agency to provide operators with additional, risk-based options that are more efficient and cost effective.

GPA Midstream Association (GPA Midstream) has served the U.S. energy industry since 1921.[4] GPA Midstream is composed of nearly 100 corporate members that are engaged in the gathering and processing of natural gas into merchantable pipeline gas, commonly referred to in the industry as "midstream activities." Such processing includes the removal of impurities from the raw gas stream produced at the wellhead as well as the extraction for sale of natural gas liquid products (NGLs) such as ethane, propane, butane, and natural gasoline or in the manufacture, transportation, or further processing of liquid products from natural gas. GPA Midstream membership accounts for more than 90% of the NGLs produced in the United States from natural gas processing.

[1] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. 36,861 (July 31, 2018).
[2] 49 C.F.R. § 192.611 (2017).
[3] *Id.*
[4] Additional information about GPA Midstream is available at https://gpaglobal.org/. Prior to April 2016, GPA Midstream was known as the Gas Processors Association.

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GPA Midstream supports PHMSA's decision to issue the ANPRM. The class location regulations are almost fifty years old and do not account for recent developments in pipeline safety technology or integrity management. Public safety is not served by requiring operators to comply with obsolete and unduly burdensome regulations. Modernization of the class location requirements is long overdue.

GPA Midstream is concerned by certain aspects of the ANPRM. PHMSA suggests that unrelated issues identified in previous advisory bulletins or during routine inspections are relevant to the decision of whether to update the class location regulations, and that the conditions in its class location special permits should form the basis for any changes that might emerge in this proceeding. The Agency also suggests that topics that are already being addressed in a separate rulemaking proceeding should limit an operator's ability to obtain class location relief. These suggestions raise serious questions about PHMSA's commitment to making meaningful improvements to the class location regulations.

To demonstrate the need for regulatory relief, Section I of this letter provides background information on the history of the class location requirements and recent advances in pipeline safety technology and risk management. Section II contains GPA Midstream's responses to the questions presented in the ANPRM. These comments reflect our preliminary views and may require revision or further explanation at subsequent phases of this proceeding.

I. Background

The class location concept originated with the 1955 edition of Section 8 of American Standard Code for Pressure Piping (B31.1.8-1955). The B31.1.8-1955 directed operators to use population density indexes to determine the class location of a pipeline segment at the time of construction. These population density indexes were laid out in 1-mile and 10-mile zones that extended a quarter mile in either direction from the centerline of a pipeline. Four class locations, varying based on the characteristics and use of the surrounding land, were recognized in the B31.1.8-1955, and a unique design factor applied to the construction and testing of a pipeline built within each class location. The primary purpose of that design factor was to provide a higher margin of safety for pipelines in more densely populated areas and other at-risk locations, like road or highway crossings.

Thirteen years later, in the 1968 edition of the B31.8 (B31.8-1968), a new provision was added for addressing class location changes that affected pipelines after initial construction. The new provision directed operators to conduct periodic inspections of pipelines operating at pressures above 40 percent of specified minimum yield strength (SMYS) to detect class location changes.[5] If an increase in population density indicated that hoop stress of the pipeline was no longer commensurate with the current class location, the operator had to complete a study and

[5] B31.8-1968, Section 850.4.

take appropriate action to confirm or revise the pipeline's MAOP.[6] Those actions included reducing the MAOP, conducting a new hydrostatic pressure test, or replacing the pipe.[7]

In 1970, PHMSA issued the final rule that established the original minimum federal safety standards for gas pipeline facilities (1970 final rule).[8] The 1970 final rule incorporated the class location provisions from the B31.8-1968, albeit with certain modifications. PHMSA eliminated the 10-mile population density index, narrowed the zone that operators had to evaluate to 1/8 mile on either side of the centerline, and established new class location definitions.[9] The Agency also adopted what is known as the "sliding mile" approach for conducting class location surveys and added a provision allowing operators to adjust the boundaries of a pipeline's class location to accommodate clusters of buildings intended for human occupancy. The sliding mile approach requires operators to consider the number of buildings intended for human occupancy within a 1-mile-long "class location unit" that moves continuously along a pipeline's centerline.

As in the B31.8-1968, the 1970 final rule included requirements for addressing class location changes that arose after a pipeline's initial construction.[10] The final rule stated that "[w]henever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at a hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established [MAOP] for a segment of existing pipeline is not commensurate with the present class location," the operator must conduct a study and take action to confirm or revise the MAOP of the affected segment.[11] In completing the study, the operator had to determine the current class location; analyze the original and currently-applicable design, construction, testing procedures for the segment; the physical condition, operation and maintenance history, and MAOP of the segment; and the extent of the area affected by the class location change. After completing the study, the operator had to confirm or

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[6] MAOP was the highest operating pressure that a pipeline could be subjected to under the B31.8-1968 and previous editions of that industry standard. B31.8-1968, Section 845.22.

[7] B31.8-1968, Section 850.42.

[8] Establishment of Minimum Standards, 35 Fed. Reg. 13,248, 13,258-59 (Aug. 19, 1970). Two years earlier, in a November 1968 final rule, PHMSA adopted the provisions in the B31.8-1968 to serve as its interim federal safety standards for gas pipeline facilities. Part 190—Interim Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline, 33 Fed. Reg. 16,500, 16,500-16,503 (Nov. 13, 1968). The 1970 final rule established the original version of Part 192, which contained the first set of permanent federal safety standards for gas pipeline facilities.

[9] Establishment of Minimum Standards, 35 Fed. Reg. at 13,258-59. The Agency defined four class locations in the regulations: Class 1, which includes an offshore location, or a class location unit with 10 or fewer buildings; Class 2, which includes a class location unit with more than 10, but fewer than 46 buildings; Class 3, which includes a class location unit with 46 or more buildings, or an area where the pipeline lies within 100 yards of either a building or "[a] small, well-defined outside area" (such as a playground, recreation area, outdoor theater, or other such place of public assembly) that is occupied by 20 or more people; and Class 4, which includes a class location unit where buildings with four or more stories above the ground are prevalent.

[10] The 1970 final rule included a regulation imposing a one-time obligation to determine the class location and confirm or establish the MAOP of higher stress pipelines operating at a hoop stress of more than 40 percent of SMYS. Establishment of Minimum Standards, 35 Fed. Reg. at 13,272. The deadlines imposed in that regulation expired in the early 1970s, and PHMSA repealed the provision in a subsequent final rule. Regulatory Review; Gas Pipeline Safety Standards, 61 Fed. Reg. 28,770, 28781 (June 6, 1996). Accordingly, the regulation is longer relevant in determining the extent of an operator's class location obligations under Part 192.

[11] Establishment of Minimum Standards, 35 Fed. Reg. at 13,272.

revise the MAOP of the affected segment, either by using the results of a prior pressure test, reducing the MAOP (if a previous pressure test had not been performed), conducting a new hydrostatic pressure test (to re-establish MAOP), or replacing the pipe.[12]

PHMSA has not made any significant alterations to the class location regulations since the 1970 final rule. The Agency modified the definition of a Class 3 location in the mid-1980s to include a specific frequency threshold for areas where a pipeline was located within 100 yards of either a building or small, well-defined outside area occupied by 20 or more persons.[13] The original definition stated that these areas had to meet the occupancy threshold during "normal use" to qualify as a Class 3 location. The revised definition contained a more explicit frequency requirement, *i.e.*, a building or small, well-defined outside area had to be occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. Several decades later, the Agency responded to a congressional mandate in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 by issuing a notice of inquiry asking for public comment on whether to expand its integrity management requirements beyond high consequence areas (HCAs) and, if so, whether that expansion would mitigate the need for the class location requirements.[14] After reviewing the public comments, PHMSA decided not to pursue any changes to the class location regulations in June 2016.[15]

Although the original class location regulations have essentially remained intact, pipeline safety practices have changed dramatically in the past several decades, particularly with respect to using In-Line Inspection (ILI) tools to conduct integrity assessments. Developed in the 1960s, the first generation of ILI tools used magnetic flux technology to identify metal loss in the bottom quarter of the pipe.[16] The technology continued to advance throughout the 1970s, leading to ILI tools that could provide more reliable and accurate high-resolution data for the entire pipe circumference.[17] Even more dramatic improvement occurred in the 1980s and 1990s.

[12] The 1970 final rule originally required operators to confirm or revise the MAOP of a segment within 1 year of the class location change. Establishment of Minimum Standards, 35 Fed. Reg. at 13,272. That 1-year deadline was later extended to 24 months, which is the timeframe imposed in the current rules. Pipeline Safety: Periodic Updates to Pipeline Safety Regulations (2001), 69 Fed. Reg. 32,886, 32, 895 (June 14, 2004).

[13] Transportation of Natural and Other Gas by Pipeline; Confirmation or Revision of Maximum Allowable Operating Pressure for Gas Pipelines, 50 Fed. Reg. 36,116 (Sept. 5, 1985); Transportation of Natural and Other Gas by Pipeline; Confirmation or Revision of Maximum Allowable Operating Pressure Near Certain Occupied Buildings and Outside Areas, 51 Fed. Reg. 29,504 (Aug. 18, 1986); Transportation of Natural and Other Gas by Pipeline; Confirmation or Revision of Maximum Allowable Operating Pressure Near Certain Occupied Buildings and Outside Areas, 52 Fed. Reg. 32,924 (Sept. 1, 1987).

[14] Pipeline Safety: Class Location Requirements, 78 Fed. Reg. 46,560 (Aug. 1, 2013) Pipeline Safety: Class Location Requirements, 78 Fed. Reg. 59,906 (September 30, 2013). PHMSA initially styled this proceeding as a Notice of Proposed Rulemaking. As part of its notice granting an extension of time to file comment, PHMSA revised the title of the regulatory action to reflect a "Notice of Inquiry."

[15] Letter from Anthony R. Fox, Secretary, U.S. Dep't of Transportation to Honorable Bill Shuster, Chairman, Committee on Transportation and Infrastructure, U. S. House of Representatives, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/55521/report-congress-evaluation-expanding-pipeline-imp-hcas-full.pdf

[16] INTERSTATE NAT. GAS ASS'N OF AM., RESPONSE TO NTSB RECOMMENDATION: HISTORICAL AND FUTURE DEVELOPMENT OF ADVANCED IN-LINE INSPECTION (ILI) PLATFORMS FOR NATURAL GAS TRANSMISSION PIPELINES (Apr. 2012), http://www.ingaa.org/File.aspx?id=19697.

[17] Matt Ellinger, *A History of In-Line Inspection Tools*, Inspectioneering Journal (Mar./Apr. 2017), https://inspectioneering.com/journal/2017-04-27/6416/a-history-of-in-line-inspection-tools.

ILI tools began utilizing ultrasonic technology for wall thickness measurement and crack detection,[18] and new circumferential magnetic flux tools were able to detect axially-oriented features.[19] ILI providers began using electromagnetic technology in the 2000s, which is now used to identify stress corrosion cracking.[20] Today, ILI tools continue to improve by providing more accurate detection and sizing of a wide array of pipeline anomalies.[21] ILI providers, along with industry groups and pipeline operators, are currently working together on developing advanced systems that will allow for enhanced detection of cracking along longitudinal seams and differentiating between metal loss and cracking within dents.[22]

ILI tools play a critical role in PHMSA's integrity management (IM) regulations for gas transmission lines.[23] Established in 2003, the IM regulations require operators to implement a risk management program for pipeline segments that are located in high consequence areas (HCAs).[24] As part of the IM program, operators identify and prioritize potential threats to covered segments and perform an integrity assessment at least once every seven years to determine the condition of the pipe.[25] Most operators use ILI tools to conduct these integrity assessments, although other methods can be used under the IM regulations. Operators analyze the information obtained from ILI tool runs to determine if a covered segment has a condition that requires remediation, or if additional preventative and mitigative measures should be put in place to prevent or mitigate the consequences of a potential failure.[26] Recent statistics indicate that the widespread use of ILI tools has reduced corrosion-related pipeline incidents by 70% since 2000.[27]

Citing the success of the IM program, the pipeline industry has expressed growing support for allowing operators to use more modern, risk-based approaches to address class location changes. Industry representatives have explained that the options allowed in the current regulations do not account for the actual condition of the pipe and require operators to take actions that impose significant costs without producing any corresponding benefit. While PHMSA can issue special permits authorizing the use of alternative approaches in specific cases, industry representatives have noted that the special permit process does not provide an adequate

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[18] *Id.*

[19] H.R. Vanaei *et al.*, *A Review on Pipeline Corrosion, In-Line Inspection (ILI), and Corrosion Growth Rate Models*, 149 Int'l J. of Pressure Vessels and Piping 43, 46 (Jan. 2017).

[20] Ellinger, *supra* note 17; INTERSTATE NAT. GAS ASS'N AM., *supra* note 16.

[21] Ellinger, *supra* note 17.

[22] Am. Petroleum Inst. & Ass'n Oil Pipe Lines, Pipeline Safety Excellence Performance Report & Strategic Plan 2017-2019 at 38 (2017), http://www.aopl.org/wp-content/uploads/2017/04/2017-API-AOPL-Pipeline-Safety-Report_low-1.pdf [hereinafter "2017 API report"].

[23] 49 C.F.R. Part 192, Subpart O.

[24] HCAs are locations where a pipeline incident could result in significant harm to people or property, such as Class 3 or Class 4 locations or areas that contain identified sites within the potential impact radius for a segment, 49 C.F.R. § 192.903.

[25] 49 C.F.R. §§ 192.913(c)(1), 192.937(a), 192.939(a), (b).

[26] PHMSA recently proposed to extend elements of the IM program to gas transmission line segments located in less populated, moderate consequence areas (MCAs). In April 2016, the Agency issued a proposed rule that would require operators to conduct integrity assessments of gas transmission lines in MCAs at certain intervals using an ILI tool or another approved method. Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722 (Apr. 8, 2016). As with the IM regulations, the proposed rule would require operators to analyze the information obtained from the integrity assessments to determine if a condition requires remediation.

[27] 2017 API report at 38.

remedy for affording relief from what has become an obsolete and unduly burdensome regulatory framework. As explained in more detail below, GPA Midstream shares these views and believes that the Agency should take appropriate action to modernize the class location regulations.

II. Comments

Question 1—When the population increases along a pipeline route that requires a class location change as defined at § 192.5, should PHMSA allow pipe integrity upgrades from Class 1 to Class 3 locations by methods other than pipe replacement or special permits? Why or why not?
Question 1a.—Should part 192 continue to require pipe integrity upgrades when class locations change from Class 1 to Class 3 locations or Class 2 to 4 locations? Why or why not?
Question 1b.—Should part 192 continue to require pipe integrity upgrades from Class 1 to Class 3 locations for the "cluster rule" (see § 192.5(c)) when 10 or fewer buildings intended for human occupancy have been constructed along the pipeline segment? Why or why not?
Question 1c.—Should part 192 continue to require pipe integrity upgrades for grandfathered pipe (e.g., pipe segments without a pressure test or with an inadequate pressure test, operating pressures above 72% SMYS, or inadequate or missing material records; see § 192.619(c))? Why or why not?

GPA Midstream believes that gas pipeline operators should be provided with more options for addressing class location changes. Pipeline technology and risk management principles have advanced significantly in the past 50 years, and PHMSA's class location regulations should be updated to account for these developments.

Pipe replacement should only be required in circumstances where the additional risk created by a class location change cannot be effectively managed by other measures. Operators typically have enough information to determine the steps that should be taken to manage an increase in population density or change in surrounding land use. To the extent that such information is lacking, operators should be afforded the opportunity to conduct whatever tests or inspections might be necessary to determine if the pipe is in suitable condition for safe operation without a replacement.

PHMSA should not impose arbitrary restrictions on an operator's ability to address class location changes with appropriate operations, maintenance, and integrity measures. Operators can conduct a risk assessment to determine the potential threats that might be created for a pipeline segment affected by an increase in population density or change in surrounding land use. Operators should be given significant discretion in using the results of that risk assessment to develop an appropriate program for managing those threats. PHMSA's focus should be on making sure that operators complete the risk assessment within a reasonable amount of time, and that appropriate documentation is maintained to substantiate future compliance.

Special permits are not a viable alternative to amending the class location regulations. The special permit process takes a significant amount of time to complete and is not intended to serve as a proxy for addressing outdated or unduly burdensome regulations. As important, PHMSA's current practice is to impose more than two dozen conditions in its class location special permits. The Agency developed these conditions nearly 15 years ago without adhering to the standard notice-and-comment rulemaking process or preparing a cost-benefit analysis. Most of the conditions are not relevant to the class location process and do not provide any justifiable improvement in public safety.

PHMSA's alternative MAOP rule demonstrates that codifying the existing class location special permit conditions will not lead to reasonable and cost-effective regulations. Originally adopted in 2008, the alternative MAOP rule ostensibly allows operators to use an alternative design factor and an alternative test pressure factor in establishing the MAOP of a pipeline segment that satisfies certain additional criteria, subject to certain exceptions. The additional criteria and exceptions imposed in that regulation were largely derived from special permits that PHMSA had issued in the years leading up to the final rule. The pipeline industry's experience with alternative MAOP rule shows why a similar approach should not be used in this rulemaking proceeding.

The alternative MAOP rule contains an onerous list of limitations that exclude most pipeline segments. The rule only applies to pipeline segments in Class 1, Class 2, or Class 3 locations that: (1) are built with steel pipe that meets additional design and construction criteria; (2) are remotely monitored and controlled by a supervisory control and data acquisition system; (3) do not contain any mechanical couplings used in place of girth welds; (4) have not experienced any failures indicative of systemic faults in material as determined by a root cause analysis; and (5) satisfy certain non-destructive examination requirements for girth welds installed prior to December 22, 2008. In addition to these extensive limitations, an operator must provide prior notice to PHMSA, submit a senior executive certification, and meet certain additional strength testing requirements to use the alternative MAOP rule for a pipeline segment. The operator must also comply with eleven additional operations and maintenance requirements. These additional operations and maintenance requirements supplement the standard Part 192 provisions and include detailed sub-requirements that impose even further obligations.

Very few operators have used the alternative MAOP rule in the past decade. Many pipeline segments are incapable of meeting the extensive limitations provided in the regulation, and the burden imposed by the additional operations and maintenance requirements cannot be justified from a compliance perspective. Most operators establish a lower MAOP without even considering the alternative MAOP rule, eliminating any benefit that might otherwise be produced by relying on the rule. Public safety is not advanced by establishing elective regulatory programs that no reasonable operator would ever pursue. Given the experience with the alternative MAOP rule, the Agency should not create a new regulation that codifies the existing class location special permit conditions into Part 192.

GPA Midstream does not believe that operators of grandfathered pipe should be subject to any further restrictions or limitations in determining eligibility for class location relief. PHMSA is already developing new regulations for verifying the materials and MAOP of grandfathered pipelines.[28] Operators can address any integrity concerns with grandfathered pipelines by complying with those regulations, and there is no need to establish additional or more stringent requirements that apply to class location changes in this proceeding. The only appropriate consideration would be to require that operators accelerate the verification of materials and MAOP for grandfathered pipeline segments as a condition of obtaining class location relief. Otherwise, the Agency should not give any special condition to this factor.

Q2—Should PHMSA give operators the option of performing certain IM measures in lieu of the existing measures (pipe replacement, lower the operating pressure, or pressure test at a higher pressure; see § 192.611) when class locations change from Class 1 to Class 3 due to population growth within the sliding mile? Why or why not?
2a.—If so, what, if any, additional integrity management and maintenance approaches or safety measures should be applied to offset the impact on safety these proposals might create?

GPA Midstream believes that gas pipeline operators can use risk management principles to address any class location changes that occur after construction without compromising public safety. PHMSA should not impose arbitrary restrictions on an operator's ability to determine what measures might be necessary or appropriate to maintain safe operation. Pipe replacement should only be required in circumstances where the additional risk created by a class location change cannot be effectively managed through these other measures.

Rather than mandating a specific list of activities that must be performed, operators should be allowed to use a risk assessment to develop an appropriate program for managing the integrity of pipeline segments affected by class location changes. PHMSA's focus should be on making sure that operators complete the risk assessment within a reasonable timeframe and maintain appropriate documentation to substantiate compliance.

Q3—Should PHMSA give operators the option of performing certain IM measures in lieu of the existing measures (pipe replacement with a more conservative design safety factor or a combination of pressure test and lower MAOP) when class locations change due to additional structures being built outside of clustered areas within the sliding mile, if operators are using the cluster adjustment to class locations per § 192.5(c)(2)? Why or why not?
3a.—If so, what, if any, additional integrity management and maintenance approaches or safety measures should be applied to offset the impact on safety these proposals might create?
3b.—At what intervals and in what timeframes should operators be required to assess these pipelines and perform remediation measures?

GPA believes that gas pipeline operators should be allowed to use the cluster rule to limit the impact of class location changes. When PHMSA adopted the original class location regulations in the 1970 final rule, the Agency added the cluster rule to allow operators to adjust the boundaries of a class location to accommodate closely grouped buildings intended for human

[28] 81 Fed. Reg. at 20,798-801, 20,812-814.

occupancy.[29] Although later consolidated into a single regulatory provision, PHMSA has not made any substantive changes to the cluster rule in the more than four decades since its issuance.[30]

The cluster rule recognizes that an elevated class location designation should not be applied to the entire length of a class location unit if the buildings intended for human occupancy are concentrated within a well-defined area. The class location framework only provides a rough approximation of the additional risk created by certain levels of population density, and the elevated class location designations should be reserved for areas where the population actually resides. The cluster rule achieves that objective by allowing operators to target resources to higher risk areas; namely, the portion of the class location unit that contains the buildings intended for human occupancy.

PHMSA should not require operators to apply a higher class location designation if a building intended for human occupancy is built outside of a cluster within a sliding mile. The higher class location designation should be reserved for the cluster, which contains the additional buildings intended for human occupancy that create the elevated risk to public safety. Operators should be allowed to determine the class location designation for the remainder of the class location unit solely by considering the number of buildings intended for human occupancy outside of the cluster, particularly if there are 10 or fewer building intended for human occupancy. There is no reason to apply the higher class location designation to the limited number of buildings outside of that area, which are otherwise representative of the sparsely populated, rural areas that contain the vast majority of the nation's gas pipelines.

> *Q4—If PHMSA allows operators to perform certain IM measures in lieu of pipe replacement when class locations change from Class 1 to Class 3, should some sort of "fitness for service" standard determine which pipelines are eligible? Why or why not?*
> *4a.—If so, what factors should make a pipeline eligible or ineligible?*
> *(i) Should grandfathered pipe (lacking records, including pressure test or material records) or pipe operating above 72% SMYS be eligible? Why or why not?*
> *(ii) Should pipe that has experienced an in-service failure, was manufactured with a material or seam welding process during a time or by a manufacturer where there are now known integrity issues or has lower toughness in the pipe and weld seam (Charpy impact value) be eligible? Should pipe with a failure or leak history be eligible? Why or why not?*
> *(iii) Should pipe that contains or is susceptible to cracking, including in the body, seam, or girth weld, or having disbonded coating or CP shielding coatings be eligible? Are there coating types that should disqualify pipe? Should some types of pipe, such as lap-*

[29] Specifically, the relevant portion of the regulation stated that "[w]hen a cluster of buildings intended for human occupancy requires a Class 3 location, the Class 3 location ends 220 yards from the nearest building in the cluster." Establishment of Minimum Standards, 35 Fed. Reg. at 13259. The regulation further stated that "[w]hen a cluster of buildings intended for human occupancy requires a Class 2 location, the Class 2 location ends 220 yards from the nearest building in the cluster." *Id.*

[30] PHMSA initiated a rulemaking proceeding to make clarifying amendments to the cluster rule in the mid-1990s, but ultimately abandoned that effort. Regulatory Review; Gas Pipeline Safety Standards, 57 Fed. Reg. 39,572 (Aug. 31, 1992); Regulatory Review; Gas Pipeline Safety Standards, 61 Fed. 28,770 (June 6, 1996); Regulatory Review; Gas Pipeline Safety Standards; Correction, 61 Fed. Reg. 35,139 (July 5, 1996).

welded, flash-welded, or low-frequency electric resistance welded pipe be ineligible? Should pipe where the seam type is unknown be ineligible? Why or why not?
(iv) Should pipe with significant corros7ion (wall loss) be eligible for certain IM measures, or should it be replaced? Why or why not?
(v) Should anomalies be repaired similar to IM, allowed to grow to only a 10-percent safety factor (§ 192.933(d)) before remediation in high population areas such as Class 2, 3 and 4 locations, or should they have an increased safety factor for remediation should these class location factors be eliminated? Why or why not?
(vi) Should pipe that has been damaged (dented) or has lost ground cover due to 3rd party activity (excavation or other) be eligible? Why or why not?
(vii) Should pipe lacking cathodic protection due to disbonded coating be eligible? Why or why not?
(viii) Should pipe with properties such as low frequency electric resistance weld (LF-ERW), lap welded, or other seam types that have a history of seam failure due to poor manufacturing properties or seam types that have a derating factor below 1.0 be eligible? Why or why not?
4b.—Should PHMSA base any proposed requirements off its criteria used for considering class location change waivers (69 FR 38948; June 29, 2004), including the age and manufacturing and construction processes of the pipe, and O&M history? Why or why not?
4c.—In the 2004 Federal Register notice (69 FR 38948), PHMSA outlines certain requirements pipelines must meet to be eligible for waiver consideration, including no bare pipe or pipe with wrinkle bends, records of a hydrostatic test to at least 1.25 times MAOP, records of ILI runs with no significant anomalies that would indicate systemic problems, and agreement that up to 25 miles of pipe both upstream and downstream of the waiver location must be included in the operator's IM program and periodically inspected using ILI technology. Further, the criteria provides no waivers for segments changing to Class 4 locations or for pipe changing to a Class 3 location that is operating above 72% SMYS. Should PHMSA require operators and pipelines to meet the threshold conditions outlined earlier in this document (Section 3A; "Class Location Change Special Permits—Special Permit Conditions) or other thresholds to be eligible for a waiver when class locations change? Why or why not?

GPA Midstream does not believe that a long list of eligibility factors should be included in a modernized version of the class location regulations. Operators should be allowed to conduct a risk assessment to determine what steps are necessary to safely manage a pipeline segment after a class location change. PHMSA should not impose unnecessary restrictions on an operator's discretion in making such determinations. The Agency should focus on making sure that the risk assessment is completed within a reasonable amount of time, and that appropriate documentation is maintained to substantiate future compliance.

PHMSA is issuing new regulations for grandfathered pipeline segments installed prior to the adoption of the original pipeline safety regulations.[31] The regulations are expected to include detailed requirements for verifying the materials and MAOP of grandfathered pipelines, and any long-term integrity concerns should be addressed by an operator's compliance with those

[31] 81 Fed. Reg. at 20,798-801, 20,812-814.

requirements. There is no need to revisit that issue again in this proceeding, except perhaps by establishing an accelerated schedule for verifying the materials and MAOP for grandfathered pipeline segments as a condition of obtaining class location relief.

Operators should be afforded the opportunity to conduct whatever tests or inspections might be necessary to determine if a pipeline is in suitable condition for safe operation following a class location change. Operators should also be allowed to develop and implement a program for addressing any threats identified in conducting those tests or inspections through appropriate remedial action. Anomalies, defects, or other conditions that could compromise the integrity of the pipeline should be repaired within an expedited timeframe.

> *Q5—As it is critical for operators to have traceable, verifiable, and complete (TVC) records to perform IM, should operators be required to have TVC records as a prerequisite for performing IM measures on segments instead of replacing pipe when class locations change? Why or why not?*
> *5a.—If so, what records should be necessary and why? Should records include pipe properties, including yield strength, seam type, and wall thickness; coating type; O&M history; leak and failure history; pressure test records; MAOP; class location; depth of cover; and ability to be in-line inspected?*
> *5b.—If operators do not have TVC records for affected segments and TVC records were a prerequisite for performing IM measures on pipeline segments in lieu of replacing pipe, how should those records be obtained, and when should the deadline for obtaining those records be?*

GPA Midstream does not agree that "it is critical for operators to have traceable, verifiable, and complete records to perform IM."[32] As indicated by the narrow context with which TVC was first introduced,[33] this heightened recordkeeping standard should only apply to MAOP records. PHMSA does not currently require operators to apply the TVC recordkeeping standard to IM records. While the Agency is currently working through proposals to add the TVC recordkeeping standard to other pipeline records, the Agency has not proposed to amend the IM recordkeeping requirement (49 C.F.R. § 192.924) specifically. In 2016, PHMSA proposed that operators apply TVC to "records that demonstrate compliance with Part 192".[34] Numerous stakeholders questioned the breadth of the proposal and stated that TVC should not be

[32] Pipeline Safety: Class Location Change Requirements, 83 Fed. Reg. at 36,869.
[33] In 2010, the National Transportation Safety Board (NTSB) included TVC in two of its safety recommendations to the Pacific Gas & Electric Company (PG&E). However, TVC only applied to MAOP records. *National Transportation Safety Board Safety Recommendation,* P-10-2, P-10-3 (Jan. 3, 2011), http://www.ntsb.gov/safety/safety-recs/recletters/P-10-002-004.pdf. In 2011 and 2012, PHMSA issued two advisory bulletins including, for the first time, a recommendation to operators to apply TVC to MAOP records. Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation, 76 Fed. Reg. 1504 (Jan. 10, 2011); Pipeline Safety: Verification of Records, 77 Fed. Reg. 26,822, 26,823 (May 7, 2012).
[34] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. at 20,808, 20,833, Proposed § 192.13(e) ("Each operator must make and retain records that demonstrate compliance with this part. (1) Operators of transmission pipelines must keep records for the retention period specified in appendix A to part 192. (2) Records must be reliable, traceable, verifiable, and complete.").

applied broadly.[35] Ultimately, the Gas Pipeline Advisory Committee (GPAC), the federal advisory committee that reviews PHMSA's rulemaking proposals, recommended that PHMSA remove its proposed §192.13(e) finding that it was not practicable, reasonable, or cost effective.[36] As discussed on the record in public meetings and in comments to the docket, TVC should only apply to MAOP records.

None of those records listed in question 5(a) other than MAOP records should be subject to the heightened TVC standard. PHMSA has not demonstrated any specific concern with the validity of the records and data operators currently use for pipeline maintenance and integrity management activities. If PHMSA were to apply the TVC requirement to these existing records, such a change could create confusion as to whether these records are still valid.

PHMSA should not create a blanket exclusion from using IM in response to a class location change. Operators have the ability through the performance of engineering analyses, integrity assessments, and other remedial measures to address any threats to the integrity of a pipeline. Rather than imposing unnecessary barriers to obtaining class location relief, PHMSA should use the process as an incentive to focus operator resources on addressing such conditions. Any integrity threats can be addressed through appropriate assessments and remedial measures as part of the IM process.

To the extent that an operator is missing certain records, the IM program already provides a process for addressing that concern. PHMSA has also spent countless resources developing methods to reconfirm MAOP[37] if records are missing and verify pipeline materials.[38] GPA Midstream supports using these processes to account for any information that is missing from existing records.

> *Q6—Should PHMSA incorporate its special permit conditions regarding class location changes into the regulations, and would this incorporation satisfy the need for alternative approaches? Why or why not? (Examples of typical PHMSA class location special permit conditions can be found at https://primis.phmsa.dot.gov/classloc/documents.htm.)*
> *6a.—What, if any, special permit conditions could be incorporated into the regulations to provide regulatory certainty and public safety in these high population density areas (Class 2, 3, and 4)?*

GPA Midstream does not believe that PHMSA should incorporate its class location special permit conditions into Part 192. More than two dozen conditions are currently included

[35] *See* Comments of the Interstate Nat. Gas Ass'n of Am. at 35-47, No. PHMSA-2011-0023, (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0407; Comments of the American Gas Association on the Safety of Gas Transmission and Gathering Pipeline Proposed Rule at 32-33, No. PHMSA-2011-0023 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0339; Comments of the American Gas Ass'n on the Safety of Gas Transmission and Gathering Pipeline Proposed Rule at 5, 28, 30, No. PHMSA-2011-0023 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0339; Comments of GPA Midstream Ass'n at 27, PHMSA-2011-0023 (July 7, 2016), https://www.regulations.gov/document?D=PHMSA-2011-0023-0290.
[36] GPAC Approved Voting Slide 6 (Mar. 2, 2018), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=939.
[37] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. at 20,833, Proposed 49 C.F.R. § 192.624 (as modified by the Gas Pipeline Advisory Committee).
[38] *Id.* at 20,831, Proposed 49 C.F.R. § 192.607.

in class location special permits, and very few address areas that are directly relevant to the class location process. For examples, several conditions focus on cathodic protection, even though the class location requirements play no role in determining the extent of an operator's obligations under PHMSA's corrosion control regulations. Others impose additional obligations relating to line markers, casings, depth of cover, girth welds, recordkeeping, and reporting. The Agency has never provided any evidence demonstrating that these conditions are necessary to offset whatever marginal risk to public safety might be created by waving the class location regulations. To the contrary, the Agency developed its conditions more than a decade ago outside of the rulemaking process. Stakeholders never received the opportunity to comment, and the GPAC never received a risk assessment or other supporting analysis. There is simply no indication that the current special permit conditions satisfy the statutory factors that PHMSA is required to consider in a rulemaking proceeding, or that the compliance costs are justified by a beneficial improvement in public safety.

The pipeline industry's experience with the alternative MAOP rule shows that the class location special permit conditions should not be codified into Part 192. The long list of limitations that PHMSA included in that rule, and the additional design, construction, testing, operation, and maintenance criteria, were largely derived from existing special permits. The limitations have the effect of excluding most pipeline segments, and the burden imposed by the additional compliance requirements cannot be justified from a cost-benefit perspective. Most pipeline operators do not even consider the alternative MAOP rule to be a viable compliance option.

Q7—For all new and replaced pipelines, to what extent are operators consulting growth and development plans to avoid potentially costly pipe change-outs in the future?

Land use and population growth are among the many factors that GPA Midstream member companies consider in determining pipeline siting.

Q8—What is the amount of pipeline mileage per year being replaced due to class location changes for pipelines: (1) Greater than 24 inches in diameter, (2) 16-24 inches in diameter, and (3) less than 16 inches in diameter?
8a.—Of this mileage, how much is being replaced due to class locations changing when additional structures for human occupancy are built near clustered areas, if operators are using the cluster adjustment to class locations per § 192.5(c)(2)?
8b.—At how many distinct locations are pipe replacements occurring due to class location changes and that involve pipe with these diameters?
8c.—What is the average amount of pipe (in miles) being replaced and cost of replacement at the locations described in question 8b and for these diameter ranges due to class location changes?

GPA Midstream does not collect this data from its member companies.

Q9—Should any additional pipeline safety equipment, preventative and mitigative measures, or prescribed standard pipeline predicted failure pressures more conservative than in the IM regulations be required if operators do not replace pipe when class

locations change due to population growth and perform IM measures instead? Why or why not?
9a.—Should operators be required to install rupture-mitigation valves or equivalent technology? Why or why not?
9b.—Should operators be required to install SCADA systems for impacted pipeline segments? Why or why not?

To maintain the risk-based approach that underpins PHMSA's pipeline safety program, operators need flexibility in the selection of IM measures in lieu of pipe replacement. GPA Midstream believes that operators should select and implement integrity measures based on the results of a risk assessment of the specific pipe where class location has changed. PHMSA should provide operators with discretion to use the results of that risk assessment to develop an appropriate program for managing the threats to that specific pipe. PHMSA's focus should be on making sure that operators complete the risk assessment within a reasonable amount of time, and that appropriate documentation is maintained to substantiate future compliance.

PHMSA should not require operators to install rupture-mitigation valves or equivalent technology. As other industry commenters have noted in recent proceedings, installation of valves does not prevent or reduce the consequences of an incident in the majority circumstances.[39] Moreover, these measures are not required by the current IM regulations.[40] PHMSA has provided no safety basis for requiring rupture-mitigation valves or equivalent technology. PHMSA does not currently list rupture-mitigation valves as a criteria when assessing class location change waivers.[41] Operators should be allowed to determine whether to install rupture-mitigation valves if the risk assessment demonstrates that such valves "would be an efficient means of adding protection."[42]

The 2012 study by Oak Ridge National Laboratory (ORNL) on automatic and remotely controlled shut-off valves supports an operator's ability to determine whether rupture-mitigation valves are appropriate given the specific pipe characteristics. ORNL concluded the success of these valves depends on the specific features of each pipeline facility.[43] ORNL found the feasibility of these valves must "reflect the actual pipeline design features and operating

[39] *See, e.g.*, Comments from the Interstate Nat. Gas Ass'n of Am. on Draft Research Report, Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety, ORNL/TM-2012/411 (Oct. 26, 2012), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=414; American Gas Ass'n Comments on the *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*, Oak Ridge National Laboratory, 2012 (Oct. 26, 2012), https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=413.
[40] 49 C.F.R. §§ 192.611, 192.935(a).
[41] PHMSA, CRITERIA FOR CONSIDERING CLASS LOCATION WAIVER REQUESTS 5 (June 30, 2004), https://primis.phmsa.dot.gov/classloc/docs/ClassChangeWaiverCriteria.pdf
[42] 49 C.F.R. § 192.935(c).
[43] OAK RIDGE NAT'L LAB., 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 189 (2012), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/16701/finalvalvestudy.pdf

conditions and the site-specific parameters appropriate for the area where the pipeline segment is located."[44]

As currently required by the IM regulations, PHMSA should allow operators to decide, after completing a risk assessment, whether to install rupture-mitigation valves as a preventive and mitigative measure.[45]

While operators utilize SCADA systems on many pipeline systems today, there is no technical or safety reason to require installation of these systems as a prerequisite for class location relief. PHMSA should allow operators to decide, after completing a risk assessment, whether to utilize SCADA systems as an additional preventive and mitigative measure. SCADA systems may be impractical for certain short pipelines, and other, simpler pipeline systems.

PHMSA has not provided any evidence that more conservative preventative and mitigative measures are appropriate when using IM measures instead of pipe replacement when class location changes. Instead, PHMSA should allow operators to complete a risk assessment that addresses pipe-specific factors and considers several additional preventative and mitigative measures that could be used to prevent or mitigate the consequences of a failure in an area where class location has changed.

PHMSA may consider enhanced damage prevention requirements instead of prescriptive requirements to use certain additional preventative and mitigative measures. Damage prevention requirements address the leading cause of pipeline incidents in HCAs—third party damage.[46]

> *Q10—Should there be any maximum diameter, pressure, or potential impact radius (PIR) limits that should disallow operators from using IM principles in lieu of the existing requirements when class locations change? For instance, PHMSA has seen construction projects where operators are putting in 42-inch-diameter pipe designed to operate at up to 3,000 psig. The PIR for that pipeline would be over 1,587 feet, which would mean the total blast diameter would be more than 3,174 feet.*

There should be no "one size fits all" approach to determining whether operators should be allowed to use IM principles in lieu of the existing requirements when class locations changes. Operators should be allowed to conduct a risk assessment to determine what steps are necessary to safely manage a pipeline segment after a class location change. PHMSA's requirements should not be based on a hypothetical situation that is an outlier when compared to most pipelines in the country. The Agency should focus on making sure that the risk assessment is completed within a reasonable amount of time, and that appropriate documentation is maintained to substantiate future compliance.

Conclusion

[44] *Id.* at 190.
[45] 49 C.F.R. § 192.935(a).
[46] *See* HCA Incidents by Cause, Gas Transmission IM Performance National Summary, https://primis.phmsa.dot.gov/gasimp/performancemeasures.htm (follow "GT IM reporting data) (last updated Sept.12, 2018) (citing Third Party Damage as causing 29.6% of HCA incidents, followed by weather related and outside forces and equipment both at 14.1%).

GPA Midstream shares PHMSA's commitment to pipeline safety and appreciates the opportunity to submit comments on the ANPRM. If you have questions, please contact me at (202) 279-1664 or by email at mhite@GPAglobal.org.

Sincerely,

Matthew Hite

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Vice President of Government Affairs
GPA Midstream Association