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AMERICAN FUEL & PETROCHEMICAL MANUFACTURERS' COMMENTS ON

THE PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION'S NOTICE OF PROPOSED RULEMAKING "PIPELINE SAFETY: VALVE INSTALLATION AND MINIMUM RUPTURE DETECTION STANDARDS"

DOCKET NO. PHMSA-2013-0255-0005
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I. INTRODUCTION

The American Fuel & Petrochemical Manufacturers ("AFPM") welcomes the opportunity to comment on the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") notice of proposed rulemaking entitled, "Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards" ("NPRM").[1] On February 6, 2020, PHMSA issued this NPRM soliciting comment on proposals to require the use of automatic or remote-controlled shut-off valves, or equivalent technology, on newly constructed or replaced natural gas or hazardous liquid pipeline facilities. The NPRM also addresses safety recommendations from the National Transportation Safety Board resulting from investigations of pipeline incidents in Marshall, Michigan and San Bruno, California. AFPM is supportive of PHMSA's intent to enhance pipeline safety by improving rupture mitigation and shorten rupture isolation times for certain onshore gas transmission and hazardous liquid pipelines.

II. AFPM'S INTEREST IN PHMSA'S NOTICE

AFPM is a national trade association representing most U.S. refining and petrochemical manufacturing capacity. AFPM's member companies produce the gasoline, diesel, and jet fuel that drive the modern economy, as well as the petrochemical building blocks that are used to make the millions of products that make modern life possible–from clothing to life-saving medical equipment and smartphones. As such, AFPM members strengthen economic and national security while supporting more than 3 million jobs nationwide.

To produce these essential goods, AFPM members depend on all modes of transportation to move their products to and from refineries and petrochemical facilities and have made significant infrastructure investments to support and improve the safety and efficiency of the transportation system. AFPM member companies depend upon an uninterrupted, affordable supply of crude oil and natural gas as feedstocks for the transportation fuels and petrochemicals they manufacture. Pipelines are the primary mode for transporting crude oil and natural gas to refiners and petrochemical facilities and refined products from those same facilities to distribution terminals serving consumer markets.

Pipelines provide a safe, reliable, efficient and cost-effective way to move bulk liquids, particularly over long distances. AFPM member companies own, operate, and rely on pipeline transportation as part of their daily operations. In 2018, U.S. refineries received over 4.2 billion barrels of crude oil via pipeline, an increase in refinery pipeline receipts of more than 28 percent since 2013.[2] AFPM members are committed to protecting the health and safety of their workers, contractors, customers, and the communities where fuels and petrochemical products are transported. AFPM supports informed, risk-based, and cost-justified regulations related to pipelines, and is committed to working with PHMSA on this issue.

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[1] *See* 85 Fed. Reg. 7162 "Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards," Docket No. PHMSA-2013-0255-0005, published February 6, 2020, https://www.federalregister.gov/documents/2020/02/06/2020-01459/pipeline-safety-valve-installation-and-minimum-rupture-detection-standards.

[2] *See* U.S. Energy Information Agency, Refinery Receipts of Crude Oil by Method of Transportation Pipeline Mileage and Facilities, accessed March 5, 2020, https://www.eia.gov/dnav/pet/pet_pnp_caprec_dcu_nus_a.htm.

III. AFPM'S COMMENTS ON PHMSA'S NOTICE

AFPM appreciates PHMSA taking this step and the opportunity to provide feedback on these proposals. The NPRM would require the installation of automatic shutoff valves ("ASV"), remote-control valves ("RCV"), or equivalent technology, on certain gas transmission and hazardous liquid pipelines. The NPRM also contains proposed requirements for rupture detection and mitigation, including provisions for improving emergency response and conducting failure investigations and analyses.

A. Rulemaking Scope

PHMSA's proposal would require operators to install ASVs, RCVs, or equivalent technology, on all new natural gas transmission and hazardous liquid pipelines 6 inches or greater in nominal diameter, unless the operator demonstrates that installation of a manual valve is justified for reasons of economic, technical, or operational infeasibility. Furthermore, for new natural gas transmission lines that meet or exceed the 6-inch diameter threshold, the valves would need to be spaced at the intervals provided in 49 CFR §§ 192.179 or proposed 192.634, as applicable.

1. New Pipelines

For new hazardous liquid pipelines that meet or exceed the 6-inch diameter threshold, the valves would need to be spaced at intervals of 15 miles or less for pipeline segments that could affect high consequence areas ("HCAs") and 20 miles or less for pipeline segments that do not affect HCAs. Additional spacing limitations would apply to valves protecting HCAs as preventive and mitigative measures under the integrity management regulations, valves protecting certain water crossings, and valves on highly volatile liquid pipelines.

AFPM is supportive of installing the automatic shutoff or remotely controlled valves on new pipelines as this would potentially mitigate the consequences of a rupture on both hazardous liquids and gas transmission pipelines. AFPM seeks clarification on specific types of equivalent technology that would be permitted. For example. would a check valve, due to its mechanical response, constitute an equivalent technology? While an exhaustive list is not feasible, AFPM suggests PHMSA provide some preamble discussion and commentary on the types of technology that would be deemed "equivalent" or a performance standard that could used to evaluate new technologies.

2. Existing Pipelines

The NPRM would also require operators to install ASVs, RCVs, or equivalent technology, on existing natural gas transmission lines and hazardous liquid pipelines 6 inches or greater in nominal diameter that are "entirely replaced," unless the operator demonstrates that installation of a manual valve is justified for reasons of economic, technical, or operational infeasibility. The phrase "entirely replaced" is limited to situations where two or more contiguous miles of pipe are replaced with new pipe. Additionally, replacements of gas transmission lines that meet these criteria would need to have rupture mitigation valves spaced at intervals specified in 49 CFR §§ 192.179 or 192.634, as proposed. New rupture-mitigation valve spacing intervals would apply to replacements of hazardous liquid pipelines that meet the criteria as well.

AFPM supports the use of automatic shutoff or remotely controlled valves on existing pipelines as this would potentially mitigate the consequences of a rupture on both hazardous liquids and gas transmission pipelines. AFPM suggests PHMSA make some clarifications when such replacements are required. According to the NPRM, all replacement pipeline segments that are over 2 continuous miles in length and could affect a high consequence area must include a minimum of one mainline valve that meets the requirements. AFPM seeks confirmation that this requirement applies to all replaced pipes meeting the 2 continuous miles and HCA threshold even if the prior pipe didn't have, or wasn't required to have, a valve prior to the replacement.

Regarding Hazardous Liquid line replacements, § 195.418 is not clear on whether rupture mitigation valves must be installed per § 195.260 as stated in § 195.418(a) or per § 195.418(b) in addition to § 195.260. Additionally, § 195.418(b)(1) appears to require an ASV if doing a 2 mile or greater replacement but it is unclear if it is just for the replacement section or the entire pipe. AFPM seeks additional clarification differentiating between a "pipeline" and "pipeline segment."

The NPRM states that PHMSA intends to define "entirely replaced" when 2 or more contiguous miles are being replaced with new pipe. While this definition is discussed in the preamble, text is not codified in the proposed §192.3. Further, the terms "entirely replaced" and "two or more contiguous miles" are used interchangeably throughout the proposed §§192.179 and 192.258. PHMSA should ensure they consistently use one term throughout these sections. PHMSA should also define the term in § 192.3 and use that term throughout the regulatory text.

Regarding the definition of "entirely replaced," PHMSA's proposed definition as "two or more contiguous miles" is not consistent with the Congressional mandate in PIPES 2011 because the definition is not consistent with the plain meaning of the statute.[3] The plain meaning of "entirely" is "in every way possible; completely."[4] Therefore, replacing 2 miles of a 100-mile pipeline would not be "entirely replaced." Entirely replaced would be 100 miles of a 100-mile pipeline. In addition, AFPM seeks clarification regarding the impact of "entirely replaced." For example, would a new 2-mile section require ASV <u>within</u> that segment or would that new segment trigger an evaluation of the <u>entire</u> pipeline segment (100-mile segment), new and existing? If a section is "entirely replaced" do the regulations apply only to the replaced segment or to the entire pipeline? "Entirely replaced," as intended to be defined by PHMSA, could create an incentive to make poor engineering decisions based on the potential consequences of a segment being "completely" replaced.

Lastly, § 192.634(b)(1)-(3) states that "all such valves on a shut-off segment are rupture-mitigation valves.'" This language would seem to preclude an operator from providing additional manual valves in excess of those required by this section for purposes other than rupture mitigation, such as for operational isolation purposes. AFPM seeks clarity if this is the intent or if operators

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[3] P. L. 112–90, "Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011," 125 Stat. 1918. Retrieved from https://www.govinfo.gov/content/pkg/PLAW-112publ90/pdf/PLAW-112publ90.pdf.
[4] *See* <u>Entirely</u>, OXFORD ENGLISH DICTIONARY, https://www.oxfordlearnersdictionaries.com/us/definition/english/entirely

are permitted to include additional manual valves above and beyond the required rupture mitigation valves for operational isolation purposes.

B. Standards for Rupture Identification and Mitigation

The NPRM also would establish Federal minimum standards for the identification of ruptures and the initiation of pipeline shutdowns, segment isolation, and other mitigative actions. This NPRM also would establish standards for improving the effectiveness of emergency response. Specifically, the proposed rupture identification and mitigation regulations require:

- Defining the term "rupture" as an event that results in an uncontrolled release of a large volume of commodity that can be determined according to specific criteria or that has been observed and reported to the operator;
- Establishing procedures for responding to a rupture;
- Declaring a rupture as soon as practicable but no longer than 10 minutes after initial notification or indication;
- Immediately and directly notifying the appropriate public safety answering point (9-1-1 emergency call centers) for the jurisdiction in which the rupture is located; and
- Responding to a rupture as soon as practicable by closing rupture-mitigation valves, with complete valve shut-off and segment isolation within 40 minutes after rupture identification.

1. Definition of "Rupture"

The definition of "rupture" as proposed by PHMSA is ambiguous. The term "rupture," as defined and applied by PHMSA in the NPRM, is "meant to encompass any type of large-volume, rapidly occurring, and uncontrolled release or failure event." AFPM is particularly interested in the definition for hazardous liquid pipeline ruptures in Part 195; however, some of our proposed revisions would also apply to gas transmission pipeline ruptures as defined in Part 192.

Given most of the requirements of the NPRM are contingent on the identification of a "rupture," PHMSA must clearly define what constitutes such an event. For Hazardous Liquid pipelines, PHMSA proposed to define a "Rupture" to mean any of the following events that involve an uncontrolled release of a large volume of hazardous liquid or carbon dioxide:

1) A release of hazardous liquid or carbon dioxide observed and reported to the operator by its field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities, and that may be representative of an unintentional and uncontrolled release event defined in paragraphs (2) or (3) of this definition;
2) An unanticipated or unplanned flow rate change of 10 percent or greater or a pressure loss of 10 percent or greater, occurring within a time interval of 15 minutes or less, unless the operator has documented in advance of the flow rate change or pressure loss the need for a higher flow rate change or higher pressure-change threshold due to pipeline flow dynamics and terrain elevation changes that cause fluctuations in hazardous liquid or carbon dioxide flow that are typically higher than a flow rate change or pressure loss of 10 percent in a time interval of 15 minutes or less; or

3) An unexplained flow rate change, pressure change, instrumentation indication or equipment function that may be representative of an event defined in paragraph (2) of this definition.

AFPM suggests that the language "large volume of hazardous liquid over a short period of time" included in the definition for "rupture" in § 195.2 is unnecessary and redundant given that the subsequent events described in the definition have specific criteria. Further, the language, "field personnel, nearby pipeline, or utility personnel, the public, local responders, or public authorities" is an unnecessarily specific list of potential observers. AFPM suggests replacing this term with ". . . reported to the operator." Furthermore, in the "Note," although "pipeline operating personnel" is not specifically defined in Part 195, it stands to reason that this would also include a "controller." Therefore stating ". . . reported to pipeline operating personnel or a controller" is redundant.

The proposed definition of "rupture" is more of an explanation of how to identify a rupture. For an alternative approach to defining rupture, PHMSA could look to its accident reporting requirements. The PHMSA accident report form defines rupture as any release that "immediately impairs operation of the pipeline." Rupture should be defined in terms of the type of mechanical failure (seam split, crack propagation) and/or volume (PHMSA flagged files from 2010 to present show the average volume for "Rupture" releases is about 4,000 barrels (bbls), with about 80% of ruptures being above 2,000 bbls).

Defining a "rupture" as a 10% pressure loss is not feasible for all locations. For example, at the delivery end of a pipeline, delivery pressures are typically 25 psig. As drafted, PHMSA's proposed language would force operators to consider a pressure drop of 2.5 psig to be a rupture. Pressure drops at this low of a level rarely would rarely indicate an actual rupture. Pipelines also typically see higher pressure changes when changing delivery tanks, making the 10% pressure loss proposal a reactionary measure that could lead to unnecessary incident reports, even in instances when no product is released. In AFPM's view, rupture is better defined as a percentage of flow leaving the pipeline, typically defined as 50% of receipt flows or higher. Based on these facts, AFPM recommends PHMSA consider the following language as an alternative for defining a hazardous liquid pipeline rupture.

§ 195.2 - Definitions.

*   *   *   *   *

Rupture means an uncontrolled release of hazardous liquid or carbon dioxide from a pipeline observed and reported to the operator that immediately impairs operation of the pipeline that:

(1) is a result of a mechanical failure, such as seam split, crack propagation; and

(2) releases a percentage of flow from the pipeline of over 50% of receipt flows for that pipeline.

Note:
Rupture identification occurs when a rupture, as defined in this section, is first observed by or reported to pipeline operating personnel.

* * * * *

2. Identification and Isolation Timelines

In the NPRM, PHMSA proposed a new § 195.418 that would establish an emergency operation standard that would require operators to isolate certain ruptured pipeline segments as soon as practicable via rupture-mitigation valves with complete segment isolation within 40 minutes of identifying a rupture. This standard would apply to newly constructed and entirely replaced onshore hazardous liquid pipelines in HCAs and could affect HCAs with nominal diameters greater than or equal to 6 inches.

When developing the proposed valve-closure time in this NPRM, PHMSA considered previous rulemakings including the "Standards for Increasing the Maximum Allowable Operating Pressure (MAOP) for Gas Transmission Pipelines" Final rulemaking,[5] and the Advanced Notice of Proposed Rulemakings for the Safety of Hazardous Liquid Pipelines and the Safety of Gas Transmission Pipelines rulemakings.[6] Specifically, the alternative MAOP rule requires operators to install RCVs and close valves within 60 minutes on applicable pipeline segments. PHMSA also considered its work on recent special permits and conditions in those permits for single, non-looped pipelines to have valves that can close within 30 minutes.

PHMSA determined the 40-minute closure time by estimating the time it takes to locate a rupture added to the time it takes to isolate the rupture. Once an operator confirms a rupture is occurring, an operator needs to determine the location of the rupture, identify the location of the mainline valves needing to be shut as well as any crossover valves and other pipeline systems that flow into or out of the impacted pipeline system. Control personnel would then identify the systems needing to be isolated, if any, and the locations of the valves necessary to do so. PHMSA also notes control personnel would work with a number of entities including but not limited to other operators, emergency responders other parties, including local distribution companies, operators of directly connected pipelines, power plants, and direct-feed manufacturing facilities to ensure that rapid valve closures do not cause emergency cascading events due to increased pressures, surges, or the lack of energy product. In the NPRM, PHMSA estimated all these actions will be completed anywhere between 5 and 15 minutes of rupture identification.

Following the location of the rupture, the operator will need to isolate the ruptured segment. An operator will begin closing the appropriate valves once a rupture is identified and located. Under emergency conditions and given operating pressures, PHMSA estimates an RCV can be closed within 5 to 15 minutes after rupture identification and location, an ASV can be closed within

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[5] *See* Fed Reg. 73202, October 17, 2008, "Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines" https://www.phmsa.dot.gov/regulations-fr/rulemaking/E8-23915
[6] *See* Fed Reg. 63774; January 4, 2011, "Safety of On-Shore Hazardous Liquid Pipelines" https://www.regulations.gov/docket?D=PHMSADocket+ID+-2010-0229 and 76 FR 5308; August 25, 2011, "Safety of Gas Transmission Pipelines" https://www.regulations.gov/docket?D=PHMSA-2011-0023

10 to 25 minutes after rupture identification, and a valve needing some type of manual actuation could be closed within 15 to 25 minutes after rupture identification. Combining these two times is how PHMSA arrived at a 40-minute threshold.

PHMSA requested comment on the thresholds for closure time and specifically invited comment as it applies to any manual valves that operators might need to install because installing ASVs, RCVs, or equivalent technology is not feasible. AFPM members believe the estimates for identification and isolation provided in the rulemaking would be reasonable for remote operated valves in most scenarios, however we have concern with applying these same standards to manual valves. According to information submitted by AFPM members after a review of their respective systems, manual valve response times in certain scenarios would potentially exceed 40 or 60 minutes. This increased response time is attributed to the location of field employees and their ability to reach remote locations and proceed to shut-off / close the valve. Some valves may take up to 10 – 20 minutes to close after arriving to the location. Based on the realities of these types of scenarios, AFPM asks that PHMSA consider flexibility for response time in situations where manual vales are located in remote/rural areas.

C. Hazardous Liquids Pipelines

1. Valve Maintenance

PHMSA proposes to revise § 195.420 to incorporate the maintenance, inspection, and operator drills required to ensure operators can close a rupture-mitigation valves as soon as practicable but no later than within 40 minutes. Demonstration and verification requirements are proposed, including point-to-point verification tests for rupture-mitigation valves that are ASVs or RCVs and initial validation drills and periodic confirmation drills for any manually or locally operated valves identified as rupture-mitigation valves. This section would also require an operator to identify corrective actions and lessons learned resulting from its validation or confirmation drills and share and implement those lessons learned across its entire network of pipeline systems.

AFPM notes that § 195.420(d) appears to be duplicative of the requirements already found in 195.446(c) and (e) and therefore should be removed. In addition, § 195.420(e) should be relocated to the emergency training section in § 195.402(e), as that appears to be more appropriate place to locate requirements on testing emergency procedures.

Regardless of the relocation, § 195.420(e)(1) and (2) appear to require that the rupture mitigation valve be closed as part of the drill each calendar year, at intervals not exceeding 15 months. AFPM is concerned with this proposal because it may cause unintended and significant disruptions (including environmental upsets) when the pipeline is the primary and/or sole source of feedstock for a major manufacturing facility, such as a refinery. AFPM members have situations where a pipeline originating from offsite storage directly feeds the crude unit of a refinery. Safely disrupting this supply can only be done during refinery shutdowns which are scheduled and complex operations. AFPM requests that PHMSA consider some sort of relief from this requirement when shutting a pipeline valve is not feasible or safe and we suggest regulatory text below. Further, § 195.420(e)(2) refers to "each operating or maintenance field work unit." This term is not defined and may not be a term or designation easily identifiable by all operators. Without a clear definition, it leads to inspectors and operators disagreeing on what constitutes a "unit." AFPM suggests deleting "each operating or maintenance field work unit" or provide a clear, unambiguous definition of the term:

> *(e) For each onshore rupture-mitigation valve identified under § 195.418 that is to be manually or locally operated:*
>
> *(1) Operators must establish the 40-minute total response time as required by § 195.418 through an initial drill and through periodic validation as required by paragraph (e)(2) of this section. Each phase of the drill response must be reviewed, and the results documented to validate the total response time, including valve shut-off, as being less than or equal to 40 minutes.*
>
> *(2) A rupture-mitigation valve within each pipeline system ~~and within each operating or maintenance field work unit~~ must be randomly selected for an annual 40-minute total response time validation drill simulating worst-case conditions for that location to ensure compliance. The response drill must occur at least once each calendar year, with intervals not to exceed 15 months. If shutting a pipeline valve is impractical, [because it would lead to the shutdown of a downstream facility,] or not safe, an operator may request, in writing, relief from PHMSA on this specified drill interval.*

PHMSA proposes to add § 195.420(f) to address remedial measures that must be taken for inoperable or malfunctioning shut-off valves. While AFPM supports the intentions of this provision, we are concerned that the rule provides no mechanism of relief if the timeline cannot be met. For example, depending on the specifics of a particular valve (especially size), 6 months may not be enough lead time to procure and permit the installation of a new valve, particularly in jurisdictions with extensive local land use permitting and public comment requirements. AFPM suggests PHMSA provide some mechanism where operators could request relief when compliance with the 6-month deadline may not be feasible:

> *(f) Each operator must take remedial measures to correct any onshore valve installed under § 195.258(c) or rupture-mitigation valve identified under § 195.418 that is found inoperable or unable to maintain shut-off as follows:*
>
> *(1) Repair or replace the valve as soon as practicable but no later than 6 months after the finding; and*
>
> *(2) Designate an alternative compliant valve within 7 calendar days of the finding while repairs are being made. ~~Repairs must be completed within 6 months.~~*
>
> *(3) If compliance with (f)(1) or (f)(2) is not feasible an operator may request, in writing, relief from PHMSA on this specified drill or repair interval.*

2. Pipeline integrity management in high consequence areas.

PHMSA proposes to revise § 195.452(i)(4) to clarify the existing requirements for the conduct of Emergency Flow Restricting Device ("EFRD") evaluations for HCAs, particularly when operators use EFRDs as rupture-mitigation valves on applicable lines. AFPM recommends removing "and assessments" as the rule primarily speaks to conducting a "risk analysis" (see paragraph (i)(1) and (i)(2)).

* * * * *

(ii) The EFRD analysis ~~and assessments~~ specified in paragraph (i)(4) of this section must be completed prior to placing into service all onshore pipelines with diameters of 6 inches or greater and that are constructed or that have had 2 or more contiguous miles of pipe replaced after [insert date 12 months after effective date of this rule]. Implementation of EFRD findings for rupture-mitigation valves must meet § 195.418.

* * * * *

3. Procedural Manual for Operations, Maintenance, and Emergencies

PHMSA proposes to revise § 195.402 to identify the areas requiring an immediate response by the operator to prevent hazards to the public, property, or the environment if the facilities failed or malfunctioned, including segments that could affect HCAs and segments with valves that are specified in §§ 195.418 and 195.452(i)(4).

AFPM recommends striking "including high consequence areas and valves" from § 195.402(c)(4) to provide clarity. There is nothing in the section that would otherwise exclude HCA's, so there is no need to specifically include it. HCAs, by definition, are a location where a release could affect the people or the environment. The passage is stating that an operator must determine which pipeline facilities would require an immediate response to prevent hazards if it failed or malfunctioned, "including high consequence areas and valves." Similarly, the removal of "and valves" would obviate any potential confusion in identifying areas where a release could affect valves, an unnecessary exercise.

* * * * *

(4) Determining which pipeline facilities are in areas that would require an immediate response by the operator to prevent hazards to the public, property, or the environment if the facilities failed or malfunctioned, ~~including segments that could affect high consequence areas and valves~~ specified in either §§ 195.418 or 195.452(i)(4).

* * * * *

In § 195.402(c)(12) "[a]nd other public officials" is too broad. This requirement should be limited to those emergency response agencies with primary jurisdiction for response to a pipeline incident. Moreover, in § 195.402 (c)(12) - "[e]ach government organization that may respond to a pipeline emergency" is an impractical request."[7] In accordance with the National Incident Management System ("NIMS"), AFPM recommends allowing an operator to identify the

[7] Although many agencies maintain mutual aid agreements with neighboring jurisdictions, a state or federal agency may enroll additional resources during a major emergency

coordinating agency identified by local or state law as the lead agency in a pipeline emergency, and/or allow communication with a regional coordinating agency (e.g. Office of Emergency Management) to meet this requirement.

* * * * *

(12) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (9-1-1 emergency call center), as well as emergency response agencies with primary jurisdiction for response to a pipeline incident ~~fire, police, and other public officials, to learn the responsibility, resources, jurisdictional area, and emergency contact telephone numbers for both local and out-of-area calls of each government organization that may respond to a pipeline emergency,~~ and to inform the officials about the operator's ability to respond to the pipeline emergency and means of communication.

* * * * *

§ 195.402(e)(1) "notice to the appropriate public safety answering point (9-1-1- emergency call center), as well as fire, police, and other public officials" is redundant, and possibly confusing, in jurisdictions where the 9-1-1 center is designated as the single point of emergency services contact. AFPM recommends allowing 9-1-1 to be the single point of contact for all jurisdictions for which the 9-1-1 center serves as such.

Further, in § 195.402(e)(7) "[t]he operator (pipeline controller or the appropriate operator emergency response coordinator) must immediately and directly notify . . ." is unnecessarily prescriptive. AFPM believes it shouldn't matter the title or function of the operator personnel that is responsible for contacting the emergency public safety answering point. In many cases, it may make sense that a local operator makes the call, as they may be most familiar with the asset, the location, and the responding agencies. AFPM recommends removing the parenthetical and simply refer to the "operator."

* * * * *

(7) ...The operator ~~(pipeline controller or the appropriate operator emergency response coordinator)~~ must immediately and directly notify the appropriate public safety answering point (9-1-1 emergency call center) or other coordinating agency for the communities and jurisdictions in which the pipeline is located after the operator determines a rupture has occurred when a release is indicated and valve closure is implemented.

* * * * *

PHMSA states in § 195.402(e)(10) "[a]ctions to be taken by a controller during an emergency in accordance with the operator's emergency plans . . ." AFPM believes this is a redundant statement, as this section is intended to describe what is required in the emergency procedures. AFPM recommends removing "the operator's emergency plans," so that it reads ". . . in accordance with §§195.418 and 195.446." Notwithstanding, AFPM recommends changing "emergency plans" to "emergency procedures" as it is referred to in 195.402. Emergency plans is specific to the gas code.

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(10) Actions required to be taken by a controller during an emergency, in accordance with ~~the operator's emergency plans and~~ §§ 195.418 and 195.446.

* * * * *

Proposed new § 195.418 would establish an emergency operations standard requiring operators to isolate certain ruptured pipeline segments as soon as practicable via rupture-mitigation valves with complete segment isolation within 40 minutes of identifying a rupture. AFPM notes that this section appears to create a new term (rupture-mitigation valve) which seems to have essentially the same meaning as the already defined term, EFRD. AFPM suggests use of the term EFRD should be replaced with the new rupture-mitigation valve term.

D. Emergency Plans

In this NPRM, PHMSA proposes a number of revisions to the emergency response procedures in § 192.615 to require that these procedures provide for rupture mitigation in response to a rupture event, including specific timing provisions relating to the identification of ruptures. The NPRM also proposes that operators must have procedures in place allowing them to identify a rupture event within 10 minutes of the initial notification to the operator and to maintain liaison with and contact the appropriate public safety answering point (9-1-1 emergency call center) in the event an operator's pipeline ruptures. AFPM provides suggested edits and areas in need of clarification below.

PHMSA proposes to revise § 192.615(a)(2) to require operators to establish and maintain adequate means of communication with the appropriate public safety officials. AFPM supports the intention of this proposal, as time is precious during a pipeline rupture and a previously established relationship and connection between operators and safety officials could help mitigate the consequences of an incident. The § 192.615(a)(2) includes the term "and other public officials" which we believe is too vague and potentially expansive. AFPM supports striking this language and explicitly noting with whom operators should liaise, specifically emergency responders. This prescriptive requirement should be limited to those emergency response agencies with primary jurisdiction for response to a pipeline incident.

In addition, PHMSA proposes to revise § 192.615(a)(2) to require notification of "each government organization that may respond to a pipeline emergency." Use of the term "may" vastly expands the universe of those that would need notification and is an unrealistic request, as the operator may not reasonably be able to identify all the possible jurisdictions and/or agencies that may be called upon. AFPM notes that although many agencies maintain mutual aid agreements with neighboring jurisdictions, a state or federal agency may enroll additional resources during a major emergency. In accordance with the National Incident Management System, the lead agency (incident commander) and/or group of agencies (unified command) would coordinate and direct the resources of all responding agencies during an emergency. Attempting to maintain separate lines of communication or plans with different responding agencies may lead to further confusion and would violate the hierarchy (unity of command) of the established incident command system.

AFPM recommends allowing an operator to identify and coordinate with the agency identified by local or state law as the lead agency in a pipeline emergency, and/or allow communication with a regional coordinating agency (e.g. Office of Emergency Management) to meet this requirement. AFPM provides our proposed revisions to § 192.615(a)(2) in a redline below.

§ 192.615 - Emergency plans.

*(a) * * **

(2) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (9-1-1 emergency call center), as well as fire, police, and other ~~public officials~~ appropriate emergency responders, to learn the responsibility, resources, jurisdictional area, and emergency contact telephone numbers for ~~both local and out-of-area calls of each government organization~~ the lead agency in a pipeline emergency, and, where appropriate the regional coordinating agency (e.g. Office of Emergency Management) that may respond to a pipeline emergency, and to inform the officials about the operator's ability to respond to the pipeline emergency and means of communication.

PHMSA proposes to revise § 192.615(a)(8) to require notification by the operators to the appropriate public safety answering point (9-1-1emergency call center), as well as the appropriate public safety officials to coordinate and share information to determine the location of the release, including both planned responses and actual responses during an emergency. AFPM notes that "notifying the appropriate public safety answering point (9-1-1 emergency call center), as well as fire, police, and other public officials" is redundant, unnecessary, and possibly confusing in jurisdictions where the 9-1-1 center is designated as the single point of emergency services contact. Also, as noted above, "and other public officials" is too vague and expansive. AFPM recommends allowing 9-1-1 to be the single point of contact for all jurisdictions for which the 9-1-1 center serves as such.

In addition, in paragraph § 192.615(a)(8), the language "the operator (pipeline controller or the appropriate operator emergency response coordinator) must immediately and directly notify..." is unnecessarily prescriptive. The title or function of the operator personnel that is responsible for contacting the emergency public safety answering point is immaterial and the language should be simplified. In many cases, it may make sense that a local operator makes the call, as they may be most familiar with the asset, the location, and the responding agencies. AFPM provides our proposed revisions to § 192.615(a)(8) in a redline below.

*   *   *   *   *

(8) Notifying the appropriate public safety answering point (9-1-1 emergency call center or other designated single point of emergency services contact)~~, as well as fire, police, and other public officials,~~ of gas pipeline emergencies to coordinate and share information to determine the location of the release, including both planned responses and actual responses during an emergency. The operator ~~(pipeline controller or the appropriate operator emergency response coordinator)~~ must immediately and directly notify the appropriate public safety answering point (9-1-1 emergency call center) or other coordinating agency for the communities and jurisdictions in which the pipeline is located after the operator determines a rupture has occurred when a release is indicated and rupture-mitigation valve closure is implemented.

*   *   *   *   *

In the proposed paragraph § 192.615(a)(11) AFPM proposes removal of redundant language as follows.

*   *   *   *   *

(11) Actions required to be taken by a controller during an emergency in accordance with ~~the operator's emergency plans and~~ §§ 192.631 and 192.634.

*   *   *   *   *

Lastly like in § 192.615(a)(2) we suggest removal of the generic term "other public officials" in §192.615(c) AFPM proposed revisions to § 192.615(c) are redlined below.

*   *   *   *   *

(c) Each operator must establish and maintain liaison with the appropriate public safety answering point (9-1-1 emergency call center), as well as fire, police, and other appropriate emergency responders ~~public officials~~ to:

*   *   *   *   *

E. Gas Transmission Lines

As customers and end users of gas pipelines, AFPM members also have a vested interest in the gas transmission proposals. Furthermore, analogous regulations and terminology, where feasible, for both hazardous liquids and gas transmission will improve regulatory clarity.

1. Change in Class Location

The proposed rule states that if a change in class location[8] requires a pipe replacement under the maximum allowable operating pressure regulations, the operator would need to comply

[8] Class location is defined in § 192.5 and is a method of differentiating areas and risks along natural gas pipelines based on the potential consequences of a hypothetical pipeline failure.

with the proposed valve installation, spacing, and shut-off requirements applicable to the new class location. Any necessary valves would be required to be installed within 24 months of the class location change. AFPM supports the requirement to update and install necessary valves to match the class location requirements within 24 months of the class location change however, we request some avenue to seek relief in specific circumstances. The requirement to have valves installed within 24 months of class location change may not be feasible in all circumstances due to circumstances outside the control of the operator, such as local permitting (especially in areas where pipeline related projects are frequently contested). There should be a process to account for such uncontrollable delays.

2. Valve maintenance

PHMSA proposes to revise § 192.745 to incorporate the maintenance, inspection, and operator drills for gas transmission pipeline operators in a similar fashion to those revisions proposed for hazardous liquids pipeline operators in § 195.420. Many of the revisions AFPM has proposed for § 195.420 can likewise be applied to § 192.745. In addition, we provide some comments to improve regulatory clarity. A brief listing of these changes is included below.

- Section 192.745(d) should be relocated to the emergency plans section in § 192.615, as that is a more appropriate place to locate requirements on testing emergency plans.
- Like our proposed revisions of the analogous provisions in Part 195 AFPM proposes the following revisions in § 192.745(d):
  - Delete "each operating or maintenance field work unit" or provide a clear, unambiguous definition of the term.
  - Provide relief from the 15-month drill interval, the 6-month timeline for remedial measures that must be take inoperable or malfunction shut-off valves, and the 7-day timeline to designate a new compliant valve, as in some circumstances these may not be feasible.

F. Preventative and Mitigative Measures

PHMSA proposes to revise § 192.935(c) to clarify the requirements for conducting ASV and RCV evaluations for HCAs, particularly when RCVs and ASVs are installed as preventive and mitigative measures associated with improved response times for pipeline ruptures. Operators would also be required to demonstrate, through the risk analysis required by this section, that any ASVs or RCVs installed under this section can comply with the proposed valve maintenance requirements at § 192.745.

Section 192.935(c)(3) states that the "risk analyses and assessments conducted under paragraph (c) of this section must be reviewed . . . or within 3 months of an incident or safety-related condition . . . and certified by the signature of a senior executive." By definition, a safety related condition exists (among other reasons) anytime an operator reduces pressure on a pipeline by 20% or more due to a defect in the pipeline. Under the PHMSA integrity management plan ("IMP") regulations such a pressure reduction is usually taken anytime an "immediate repair condition" (§ 192.933(d) and §195.452(h)(4)) is identified through the IMP program.[9] In 2018 (according to PHMSA annual reports), 173 such conditions were discovered. Under this proposed provision, each one of those 173 instances would have to undergo a risk analysis (or assessment) that would need to be certified by a senior executive official. AFPM believes this requirement is unnecessarily burdensome and provides no additional safety benefit outside of what is already required as part of the IMP program and as such should be removed.

Further, AFPM recommends removing the requirement to be certified by a senior executive. Currently, only the integrity management portions of the annual report are required to be signed off be a "Senior Executive Officer." This is a requirement of the Pipeline Safety Act.[10] However, the Act does not require a Senior Executive Officer ("SEO") to certify any other information. An SEO is typically a Vice President, President, or CEO. For a once a year activity (i.e. annual report) the burden is reasonable. However, PHMSA provides no explanation as to why an officer of the company is necessary to certify a risk analysis conducted after each accident (or safety related condition for gas). This is especially problematic because these are required, not only for ruptures, but for any accident where one of the "rupture mitigation valves" is closed. Most operators would likely close these remote valves upon any size leak to isolate the segment. In the case of IMP data on the annual report, the SEO is certifying "facts" to be true (miles inspected, etc.). However, a risk analysis is not always hard facts, but rather technical opinions. This may be much more difficult for an SEO to certify if he or she was not directly involved in the analysis. Also, based upon PHMSA's proposed criteria for conducting such reviews, there may be a significant greater burden (many more than just annually) in requiring a company officer to certify each one.

§ 192.935

What additional preventive and mitigative measures must an operator take?

* * * * *

(c) * * * * *

(3) Periodic evaluations. *Risk analyses ~~and assessments~~ conducted under paragraph (c) of this section must be reviewed by the operator for new or existing operational and integrity matters that would affect rupture mitigation on an annual basis, not to exceed a period of 15 months, ~~or within 3 months of an incident or safety-related condition,~~ as those terms are defined at §§ 191.3 and 191.23, respectively~~, and certified by the signature of a senior executive of the company~~.*

* * * * *

[9] *See* 72 FR 39012; July 17, 2007, "Implementing Integrity Management - Final Rule" https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-transmission-integrity-management/60761/finalruleamendedgas071707.pdf

[10] *See* 49 USC 60109, "High-density populations areas and environmentally sensitive areas" https://www.law.cornell.edu/uscode/text/49/60109

IV. CONCLUSION

AFPM thanks PHMSA for its time and consideration of our comments related to this proposal. AFPM acknowledges the need improve operational practices that in turn will improve rupture mitigation and shorten rupture isolation times for certain onshore gas transmission and hazardous liquid pipelines. AFPM shares PHMSA's goal of increasing pipeline safety and we look forward to the opportunity to work together on this. Please contact me at (202) 457-0480 or rbenedict@afpm.org if you wish to discuss these issues further.

Sincerely,

Rob Benedict,
Senior Director Petrochemicals,
Transportation, and Infrastructure