

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

Pipeline Safety: Valve Automation & Minimum
Rupture Detection Standards

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Docket No. PHMSA-2013-0255

COMMENTS IN RESPONSE TO GAS PIPELINE ADVISORY COMMITTEE MEETING

**FILED BY
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I. Introduction

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

Pipeline safety is the top priority of the Associations and our members. In general, the Associations support PHMSA’s proposal to require the use of automated valve technology on new gas transmission pipelines and significant replacement projects. While pipeline emergencies are rare, operators must be prepared for a quick and safe response. Automated valve technology can be a valuable incident response tool where it is technically and operationally feasible and effectively reduces risk.

On July 22–23, 2020, PHMSA convened both a Gas Pipeline Advisory Committee (GPAC) meeting and a Liquid Pipeline Advisory Committee (LPAC) meeting to review the Proposed Rule.⁶ The meetings provided the GPAC and LPAC Members, PHMSA representatives, pipeline operators, and the public the opportunity to discuss and provide input on the Proposed Rule. Below the Associations propose changes to the NPRM’s regulatory text to reflect the votes and discussions held by the GPAC, LPAC, and PHMSA. The Associations believe that incorporating these proposed changes into the final rule will ensure that the rule enhances pipeline safety, provides clear requirements, and leads to an efficient use of pipeline operators’ resources.

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

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

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

⁴ INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 25 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA’s members operate nearly 200,000 miles of pipelines and serve as an indispensable link between natural gas producers and consumers.

⁵ Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards, 85 Fed. Reg. 7,162 (Feb. 6, 2020).

⁶ Pipeline Safety: Meeting of the Gas and Liquid Pipeline Safety Advisory Committees (June 22, 2020)

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

Below is a consolidated set of Associations' proposed modifications to the Proposed Rule regulatory text **in red**. These proposed modifications were explained and included in Parts I—XI above.

§192.3 Definitions.

Notification of Potential Rupture means any of the following events that involve an **unintentional and uncontrolled release of a large volume of gas from a transmission pipeline**:

- (1) A release of gas **observed or 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 **meeting defined in paragraphs (2) or (3) of this definition is observed by or reported to the operator by its field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities;**
- (2) **The operator observes** an unanticipated or unplanned pressure loss **outside of the pipeline's normal operating parameters, as defined in the operator's procedures. of 10 percent or greater, occurring within a time interval of 15 minutes or less, unless the operator has documented in advance of the pressure loss the need for a higher pressure change threshold. The operator must document the operational changes** due to pipeline flow dynamics **(pressure, flow rate, or volume) that cause fluctuations in gas demand that would not normally indicate a rupture that are typically higher than a pressure loss of 10 percent in a time interval of 15 minutes or less;** or
- (3) **The operator observes** an unexplained flow rate change, pressure change, instrumentation indication, or equipment function that may be representative of an event **meeting defined in paragraph (2) of this definition.**

Note: ~~Rupture identification~~ **Notification of a potential rupture** occurs when an **event rupture, as defined in this section,** is first observed by or reported to pipeline operating personnel or a controller.

[...]

§ 192.179 Transmission line valves.

[...]

- (e) **For** all onshore transmission line segments with diameters greater than or equal to 6 inches that are **newly** constructed or **for projects where 2 or more miles within five contiguous miles have been entirely replaced during a 24-month period** after **[DATE 24 12 MONTHS AFTER PUBLICATION EFFECTIVE DATE OF FINAL RULE]**, **the operator** must **install** ~~have~~ automatic shutoff valves, remote-control valves, or equivalent technology **whenever an additional valve must be installed at intervals to** meeting the appropriate valve spacing requirements of this section. An operator may only install a manual valve under this paragraph if it can demonstrate to PHMSA that installing an automatic shutoff valve, remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible. An operator using alternative equivalent technology or **a** manual valve must notify PHMSA in accordance with the procedure in **paragraph (f). § 192.634(h).** All valves and technology installed under this paragraph must meet the requirements of § 192.634(c)~~(f), (d), (f), and (g).~~ **This subsection does not apply to segments in class 1, 2, or 3 locations that have a potential impact radius (PIR) less than or equal to 150 feet.**
- (f) **Alternative equivalent technology or manual valves. If an operator elects to use alternative equivalent technology or a manual valve in accordance with paragraph (e), the operator must notify PHMSA at least 90 days in advance of installation or use in accordance with § 192.18. The operator must include a technical and safety evaluation in its notice to PHMSA, including design,**

construction, and operating procedures for the alternative equivalent technology or manual valve. Operators installing manual valves must also demonstrate that installing an automatic shutoff valve, a remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible. When reviewing these notifications, PHMSA will consider factors such as closure time, service reliability, access to communications and power, terrain, and population density. An operator may proceed to use the alternative equivalent technology or manual valve 91 days after submitting the notification unless it receives a letter from the Associate Administrator of Pipeline Safety informing the operator that PHMSA objects to the proposed use of the alternative equivalent technology or manual valve or that PHMSA requires additional time to conduct its review.

- (g) Replacements. Nothing in this section applies to replacements of existing pipeline segments involving less than two miles of pipe, except as required under § 192.610. The valve spacing requirements of this section do not apply to pipeline replacements that comply with the rupture-mitigation valve spacing requirements in § 192.634(b).

[...]

§ 192.610 Change in class location: change in valve spacing.

- (a) If a class location change on a transmission line occurs after [EFFECTIVE DATE OF FINAL RULE] and results in pipe replacement of two or more miles within five contiguous miles during a 24-month period to meet the maximum allowable operating pressure requirements in §§ 192.611, 192.619, or 192.620, then the requirements in §§ 192.179 and 192.634, as appropriate, apply to the new class location, and the operator must install valves as necessary to comply with those sections. Such valves must be installed within 24 months of the class location change in accordance with § 192.611(d).
- (b) If a class location change on a transmission line occurs after [EFFECTIVE DATE OF FINAL RULE] and results in pipe replacement of less than two miles within five contiguous miles during a 24-month period to meet the maximum allowable operating pressure requirements in §§ 192.611, 192.619, or 192.620, then the operator must either:
- (1) Comply with the valve spacing requirements of § 192.179(a) for the replacement; or
 - (2) Install or use existing rupture-mitigation valves so that the entirety of the replacement is between at least two rupture-mitigation valves. The distance between rupture-mitigation valves for the replacement must not exceed 20 miles. The rupture-mitigation valves must comply with all requirements of § 192.634(c)-(f).
- (c) This section does not apply to pipe replacements that amount to less than 1,000 feet within one contiguous mile during a 24-month period.

[...]

§192.615 Emergency plans.

- (a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
- (1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.
 - (2) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (9-1-1 emergency call center), where available, as well as 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.

Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9-1-1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity.

- (3) Prompt and effective response to a notice of each type of emergency, including the following:
 - (i) Gas detected inside or near a building.
 - (ii) Fire located near or directly involving a pipeline facility.
 - (iii) Explosion occurring near or directly involving a pipeline facility.
 - (iv) Natural disaster.
 - (4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.
 - (5) Actions directed toward protecting people first and then property.
 - (6) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, and pressure reduction, in any section of the operator's pipeline system necessary to minimize hazards of released gas to life, property or the environment. Each operator installing valves in accordance with § 192.179(e) or subject to the requirements in § 192.634 must also **develop written rupture identification procedures to** evaluate and identify a **notification of potential** rupture as defined in § 192.3 as being an actual rupture event or non-rupture event in accordance with operating procedures **as soon as practicable following but within 10 minutes** of the initial notification to or by the operator, regardless of how the rupture is initially detected or observed.
 - (7) Making safe any actual or potential hazard to life or property.
 - (8) ~~Notifying the appropriate public safety answering point (9-1-1 emergency call center), 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 notifying the appropriate public safety answering point (9-1-1 emergency call center), **where available,** 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 **to coordinate and share information to determine the location of the release, regardless of whether the segment is subject to the requirements of § 192.179(e) or § 192.634.**
 - (9) Safely restoring any service outage.
 - (10) Beginning action under §192.617, if applicable, as soon after the end of the emergency as possible.
 - (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.
- (b) Each operator shall:
- (1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.
 - (2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.
 - (3) Review employee activities to determine whether the procedures were effectively followed in each emergency.
- (c) Each operator shall establish and maintain liaison with the appropriate public safety answering point

(9-1-1 emergency call center), as well as fire, police, and other public officials. **Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9-1-1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity. The purpose of the liaison shall be** to:

- (1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;
- (2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;
- (3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and
- (4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

[...]

§192.617 Investigation of failures.

- (a) *Post-incident procedures.* Each operator must establish and follow post-incident procedures for investigating and analyzing failures and incidents as defined in 191.3, including sending the failed pipe, component, or equipment for laboratory testing or examination, where appropriate, to determine the causes and contributing factors of the failure or incident and minimize the possibility of a recurrence.
- (b) *Post-incident lessons learned.* Each operator must develop, implement, and incorporate lessons learned from a post-incident review into its procedures, including in pertinent operator personnel training and qualification programs, and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications, **where reasonable and practicable.**
- (c) *Analysis of rupture and valve shut-offs; preventive and mitigative measures.* **If an failure or** incident involves a rupture **of a gas transmission line as defined in § 192.3** or the closure of a rupture-mitigation valve as defined in § 192.634, the operator must also conduct a post-incident analysis of all factors impacting the release volume and the consequences of the release, and identify and implement preventive and mitigative measures to reduce or limit the release volume and damage in a future failure or incident. The analysis must include all relevant factors impacting the release volume and consequences, including, but not limited to, the following:
 - (1) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the release or failure event;
 - (2) Appropriateness and effectiveness of procedures and pipeline systems, including SCADA, communications, valve shut-off, and operator personnel;
 - (3) Actual response time from rupture detection to initiation of mitigative actions, and the appropriateness and effectiveness of the mitigative actions taken;
 - (4) Location and the timeliness of actuation of rupture-mitigation valves identified under § 192.634; and
 - (5) All other factors the operator deems appropriate.
- (d) *Rupture post-incident summary.* If a failure or incident involves a rupture **of a gas transmission line as defined in § 192.3** or the closure of a rupture-mitigation valve as defined in § 192.634, the operator must complete a summary of the post-incident review required by paragraph (c) of this section within 90 days of the failure or incident, and while the investigation is pending, conduct quarterly status reviews until completed. The post-incident summary and all other reviews and analyses produced under the requirements of this section must be reviewed, dated, and signed by the appropriate senior executive officer. The post-incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline.

[...]

§ 192.634 Transmission lines: Onshore valve shut-off for rupture mitigation.

- (a) **Applicability.** For onshore transmission pipeline segments with nominal diameters of 6 inches or greater in high consequence areas or Class 3 or Class 4 locations that are **newly** constructed or where 2 or more ~~contiguous~~ miles **within five contiguous miles** have been replaced **during a 24-month period** after **[DATE 24 12 MONTHS AFTER PUBLICATION EFFECTIVE DATE OF FINAL RULE]**, an operator must install **or use existing** rupture-mitigation valves according to the requirements of this section. Rupture-mitigation valves must be operational within **14 7** days of placing the new or replaced pipeline segment in service. **This section does not apply to segments in class 1, 2, or 3 locations that have a potential impact radius (PIR) less than or equal to 150 feet.**
- (b) **Maximum spacing between valves.** Rupture-mitigation valves must be installed in accordance with the following requirements:
- (1) **Shut-off Segment.** **For purposes of this subsection, “shut-off segment” means the segment of pipe located between the upstream mainline valve closest to the upstream endpoint of the new or replaced Class 3 or 4 or high consequence area segment and the downstream mainline valve closest to the downstream endpoint of the new or replaced Class 3 or 4 or high consequence area segment. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, the shut-off segment also extends to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or 4 locations or high consequence area segments may be contained within a single shut-off segment.**
 - (2) **Rupture-Mitigation Valves.** **Valves needed to isolate the entire shut-off segment in accordance with the spacing requirements of this subsection are “rupture-mitigation valves.” The operator is not required to select the closest valve to the shutoff segment as the rupture-mitigation valve. The operator may use a station valve as a rupture-mitigation valve. A downstream rupture-mitigation valve is not required where the distance between the end of the transmission line and the upstream rupture-mitigation valve complies with the spacing requirements in this subsection.**
 - (3) **High Consequence Areas.** **For purposes of this paragraph (b)(1), “shut off segment” means the segment of pipe located between the upstream mainline valve closest to the upstream high consequence area segment endpoint and the downstream mainline valve closest to the downstream high consequence area segment endpoint so that the entirety of the high consequence area segment is between at least two rupture mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut off segment between the upstream and downstream mainline valves, then the segment also extends to the nearest valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut off segment). All such valves on a shut off segment are “rupture mitigation valves.” Multiple high consequence areas may be contained within a single shut off segment. The distance between rupture-mitigation valves for each shut-off segment **containing a high consequence area** must not exceed:**
 - (i) 8 miles if one or more high consequence areas in the shutoff segment is in a Class 4 location;
 - (ii) 15 miles if one or more high consequence areas in the shutoff segment is in a Class 3 location, and
 - (iii) 20 miles if all high consequence areas in the shutoff segment are located in Class 1 or 2

locations, or

(iv) The mainline valve spacing requirements of § 192.179 when mainline valve spacing does not meet § 192.634(b)(31)(i), (ii), or (iii).

- (4) *Class 3 locations.* For purposes of this paragraph, “shut-off segment” means the segment of pipe located between the upstream mainline valve closest to the upstream endpoint of the Class 3 location and the downstream mainline valve closest to the downstream endpoint of the Class 3 location so that the entirety of the Class 3 location is between at least two rupture-mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, the shut-off segment also extends to the nearest valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). All such valves on a shut-off segment are “rupture-mitigation valves.” Multiple Class 3 locations may be contained within a single shut-off segment. The distance between mainline valves serving as rupture-mitigation valves for each shut-off segment **containing a class 3 location** must not exceed 15 miles.
- (5) *Class 4 locations.* For purposes of this paragraph, “shut-off segment” means the segment of pipe between the upstream mainline valve closest to the upstream endpoint of the Class 4 location and the downstream mainline valve closest to the downstream endpoint of the Class 4 location so that the entirety of the Class 4 location is between at least two rupture-mitigation valves. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, the shut-off segment also extends to the nearest valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). All such valves on a shut-off segment are “rupture-mitigation valves.” Multiple Class 4 locations may be contained within a single shut-off segment. The distance between mainline valves serving as rupture-mitigation valves for each shut-off segment **containing a class 4 location** must not exceed 8 miles.
- (6) *Laterals.* Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have rupture-mitigation valves that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of these laterals contributing gas volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment gas volume, based upon maximum flow volume at the operating pressure. **A check valve may be used as a rupture-mitigation valve where it is positioned to stop the flow of gas into the shut-off segment. Check valves used as rupture-mitigation valves in accordance with this paragraph are not subject to subsections (c)–(f).**
- (7) *Crossovers.* **An operator may use a manual valve as a rupture mitigation valve for a crossover connection if during normal operations the valve is closed to prevent the flow of gas with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must document that the valve has been locked in accordance with the operator’s procedures.**

~~(c) Valve shut-off time for rupture mitigation. Upon identifying a rupture, the operator must, as soon as practicable:~~

- ~~(1) Commence shut-off of the rupture-mitigation valve or valves which would have the greatest effect on minimizing the release volume and other potential safety and environmental consequences of the discharge to achieve full rupture-mitigation valve shut-off within 40 minutes of rupture identification; and~~
- ~~(2) Initiate other mitigative actions appropriate for the situation to minimize the release volume~~

~~and potential adverse consequences.~~

- (c) *Valve shut-off capability.* Onshore transmission line rupture-mitigation valves must have actuation capability (i.e., remote-control shut-off, automatic shut-off, equivalent technology, or manual shut-off where personnel are in proximity) to ensure pipeline ruptures are promptly mitigated based upon maximum valve shut-off times, location, and spacing specified in paragraphs (b) and ~~(de)~~ of this section to mitigate the volume and consequence of gas released.
- (d) *Valve shut-off methods.* All onshore transmission line rupture-mitigation valves must be actuated by one of the following methods to mitigate a rupture as soon as practicable but within ~~3040~~ minutes of rupture identification:
- (1) Remote control from a location that is continuously staffed with personnel trained in rupture response to provide immediate shut-off following identification of a rupture or other decision to close the valve;
 - (2) Automatic shut-off following identification of a rupture; or
 - (3) Alternative equivalent technology that is capable of mitigating a rupture in accordance with this section.
 - (4) *Manual operation upon identification of a rupture.* Operators using a manual valve in accordance with § 192.179(e), must appropriately station personnel to ensure valve shut-off in accordance with ~~paragraph (c) of~~ this section. Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to manually shut off all valves, not to exceed the ~~3040~~ minute ~~total~~ response time in ~~paragraph (c)(1) of~~ this section. **For manual valves installed in class 1 locations that are not high consequence areas, closure time may exceed 30 minutes from rupture identification if the operator provides an alternative closure time in the notification to PHMSA required under § 192.179(f).**
 - (5) **Open Valves. An operator may leave a rupture-mitigation valve open for more than 30 minutes following rupture identification if the operator, in coordination with appropriate local emergency responders, determines that is safe to leave the valve open. Operators must have written procedures for determining whether to leave a rupture-mitigation valve open, including plans to communicate with local emergency responders, minimize environmental impacts, and notify the PHMSA pipeline safety regional office where the pipeline is in service. An operator must also notify the state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement or where an intrastate pipeline is regulated by that state.**
- (e) *Valve monitoring and operation capabilities.* Onshore transmission line rupture-mitigation valves actuated by methods in paragraph ~~(de)~~ of this section must be capable of being:
- (1) Monitored or controlled by either remote or onsite personnel;
 - (2) Operated during normal, abnormal, and emergency operating conditions; **and**
 - (3) ~~Mon~~itored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. **For automatic shut-off valves, valve status need not be monitored remotely if the operator has the capability to monitor pressures or gas flow rates on the pipeline to be able to identify and locate a rupture.** Pipeline segments that use manual valve operation must have the capability to monitor pressures ~~and-or~~ gas flow rates on the pipeline to be able to identify and locate a rupture;
 - (4) ~~initiated to close as soon as practicable after identifying a rupture and with complete valve shut-off within 40 minutes of rupture identification as specified in paragraph (c) of this section; and~~
 - (5) ~~Monitored and controlled by remote personnel or must have a back-up power source to~~

~~maintain SCADA or other remote communications for remote control shut-off valve or automatic shut-off valve operational status.~~

- (f) *Monitoring of valve shut-off response status.* Operating control personnel must continually monitor rupture-mitigation valve position and operational status of all rupture-mitigation valves for the affected shut-off segment during and after a rupture event until the pipeline segment is isolated. Such monitoring must be maintained through continual electronic communications with remote instrumentation or through continual verbal communication with onsite personnel stationed at each rupture-mitigation valve, via telephone, radio, or equivalent means.
- ~~(g) *Alternative equivalent technology or manual valves for onshore transmission rupture mitigation.* If an operator elects to use alternative equivalent technology or manual valves in accordance with § 192.179(e), the operator must notify PHMSA at least 90 days in advance of installation or use in accordance with § 192.949. The operator must include a technical and safety evaluation in its notice to PHMSA, including design, construction, and operating procedures for the alternative equivalent technology or manual valve. Operators installing manual valves must also demonstrate that installing an automatic shutoff valve, a remote-control valve, or equivalent technology would be economically, technically, or operationally infeasible. An operator may proceed to use the alternative equivalent technology or manual valves 91 days after submitting the notification unless it receives a letter from the Associate Administrator of Pipeline Safety informing the operator that PHMSA objects to the proposed use of the alternative equivalent technology or manual valves or that PHMSA requires additional time to conduct its review.~~

[. . .]

§ 192.745 Valve maintenance: Transmission lines.

- (a) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.
- (b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.
- ~~(c) For each valve installed under § 192.179(e) and each rupture mitigation valve under § 192.634 that is a remote control shut-off or automatic shut-off valve, or that is based on alternative equivalent technology, the operator must conduct a point-to-point verification between SCADA displays and the mainline valve, sensors, and communications equipment in accordance with § 192.631(c) and (e).~~
- (c) For **each** rupture-mitigation valves under § 192.634 that **are is** manually or locally operated **(i.e., not automatic or remotely controlled)**:
- (1) Operators must establish the **3040**-minute ~~total~~ response time as required by § 192.634 through an initial drill and through periodic validation as required in paragraph **(dc)**(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 **3040** minutes following rupture identification, **unless the operator has established a response time greater than 30 minutes for a valve in a class 1 location that is not in a high consequence area and notified PHMSA under § 192.634(d)(4).**
 - (2) A mainline valve serving as a rupture-mitigation valve within each pipeline system and within each operating or maintenance field work unit must be randomly selected for an annual **3040**-minute ~~total~~ response time **(or alternate response time established under § 192.634(d)(4))** validation drill that simulates **reasonable** worst-case conditions for that location to ensure compliance. **Twenty-five percent valve closure is sufficient to validate response time.** The response drill must occur at least once each calendar year, with intervals not to exceed 15

months.

- (3) If the 3040-minute maximum response time (or alternate response time established under § 192.634(d)(4)) cannot be validated or achieved in the drill, the operator must revise response efforts to achieve compliance with § 192.634 as soon as practicable but no later than 12 6 months after the drill. Alternative valve shut-off measures must be in place in accordance with paragraph (de) of this section within 7 days of a failed drill.
- (4) Based on the results of response-time drills, the operator must include lessons learned in:
 - (i) Training and qualifications programs; and
 - (ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and
 - (iii) Any other areas identified by the operator as needing improvement.
- (d) Each operator must take remedial measures to correct any valve installed under § 192.179(e) or any rupture-mitigation valve identified in § 192.634 that is found to be inoperable or unable to maintain effective shut-off, as follows:
 - (1) Repair or replace the valve as soon as practicable but no later than 12 6 months after finding that the valve is inoperable or unable to maintain shut-off. An operator must notify PHMSA in accordance with § 192.18 if a valve cannot be repaired or replaced within 12 months; and
 - (2) Designate an alternative shut-off compliant valve within 7 calendar days of the finding while repairs are being made and document an interim response plan.

[...]

§192.935 What additional preventive and mitigative measures must an operator take?

[...]

- (c) *Risk analysis for gas releases and protection against ruptures.* If an operator determines, based on a risk analysis, that an automatic shut-off valve (ASV) or remote-control valve (RCV) would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of rupture leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

~~(1) Protection of onshore transmission high consequence areas from ruptures. An operator of an onshore transmission pipeline segment that is constructed, or that has 2 or more contiguous miles replaced, after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE] and is greater than or equal to 6 inches in nominal diameter and is located in a high consequence area must provide for the additional protection of those pipeline segments to assure the timely termination and mitigation of rupture events by complying with §§ 192.615(a)(6), 192.634, and 192.745. At a minimum, the analysis specified in paragraph (c) of this section must demonstrate that the operator can achieve the following standards for termination of rupture events:~~

- ~~(i) Operators must identify a rupture event as soon as practicable but within 10 minutes of the initial notification to or by the operator, in accordance with § 192.615(a)(6), regardless of how the rupture is initially detected or observed;~~
- ~~(ii) Operators must begin closing shut-off segment rupture-mitigation valves as soon as practicable after identifying a rupture in accordance with § 192.634; and~~
- ~~(iii) Operators must achieve complete segment shut-off and isolation as soon as practicable after rupture detection but within 40 minutes of rupture identification in accordance with § 192.634.~~

~~(2) Compliance deadlines. The risk analysis and assessments specified in paragraph (c) of this~~

~~section must be completed prior to placing into service onshore transmission pipelines constructed or where 2 or more contiguous miles have been replaced after **[DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE]**. Implementation of risk analysis and assessment findings for rupture mitigation valves must meet § 192.634.~~

- (1) *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.

[...]



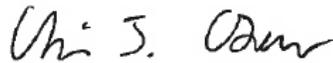
Respectfully submitted,
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