East Goshen Township
Pipeline Task Force Workshop Agenda
Thursday, March 12, 2020
5:00 PM

1. Call to Order

2. Pledge of Allegiance / Moment of Silence

3. Ask if anyone is recording the meeting

4. Approval of Minutes
   February 27, 2020

5. Public Comment

6. Chairperson's Report (none)

7. Reports (none)

8. Old Business (none)

9. New Business
   a. Consider BOS Recommendation for public comment to PHMSA regarding their proposal to its regulations concerning natural gas and hazardous liquid pipelines. (Public comments due by 4/6/20)

10. Any Other Matter (none)

11. Correspondence (none)

12. Adjournment

PIPELINE TASK FORCE MEETING
1580 PAOLI PIKE
THURSDAY, February 27, 2020
DRAFT MINUTES

Members Present:
Caroline Hughes, Chair; Bill Wegemann, Vice Chair; Members: Judi DiFonzo; Christina Morley; Gerry Sexton

Others Present:
Rick Smith, Township Manager; Michele Truitt, Township Supervisor

COMMON ACRONYMS:

BOS - Board of Supervisors
CCATO - Chester County Association of Township Officials
DEP - Department of Environmental Protection
EGSEA - East Goshen Safety and Environmental Advocates
HDD - Horizontal Directional Drilling
IR - Inadvertent Return
ME1 - Mariner East 1
ME2 - Mariner East 2
PHMSA - Pipeline Hazard Materials and Safety Administration
PUC - Public Utility Commission
TF - Task Force

Call to Order & Pledge of Allegiance
Caroline called the meeting to order at 5:00 p.m. and Christina led the pledge of allegiance.

Moment of Silence
Caroline called for a moment of silence to honor those we have lost.

Recording
Caroline asked if anyone was recording the meeting. No one was recording.

Public Comment
Michele provided a summary of the meeting that she and Supervisor John Hertzog attended with East Goshen staff and two Sunoco representatives. The representatives from Sunoco explained how the programmable logic controllers along the pipeline are connected and how the communications functions normally and during a failure. She continued that they learned about a grant that is available to the township emergency service staff for gas meter equipment. Two items that the Sunoco representatives could not address were: 1) What size leak can be detected and 2) What is the threshold for shutdown. Michele concluded that she told Sunoco representatives that improving communications between Energy Transfer and East Goshen Township should be a priority.

Approval of Minutes

The minutes from January 23, 2020, were unanimously approved as amended.

Chairperson's Report

1. Caroline reported that the PUC fined Sunoco $200,000 and called for a remaining life study of ME1 following a prior pipeline leak in Morgantown, Berks County.
2. Caroline stated that the U.S. Department of Justice has launched an investigation into Energy Transfer's handling of a pipeline explosion in Western PA.
3. Caroline explained that a resident reported a PECO gas line was hit by Sunoco when they were excavating at the site near the Chester County Library. Rick stated that since the line was not marked, it was unknown that it existed.

Reports

1. **Legislative Update –** Bill summarized that stocks pertaining to the oil/pipeline industry are at all-time lows partly because of the due diligence from local groups and citizens.
   Bill reported that Governor Wolf is due to veto the Petchem Bill which will deny the state economic stimulus.
   Bill noted at Senator Killion's tele town hall no attendee asked a question in reference to the pipeline.
2. **Current Pipeline Events Impacting East Goshen –** Rick gave the following update via email prior to the meeting. *"HDD 461 – Still doing the initial bore with pull back to occur in April, HDD 500 – installing casing at south end of the HDD. Need to install casing at New Kent. They plan to drill from both ends and meet in the middle. HDD 520/530 – Casing for 20" pipeline installed at Bow Tree. Connecting the 16" pipelines at Bow Tree."*

New Business

1. It was agreed by the TF that a workshop meeting will be held on March 12, 2020, at 5:00 p.m. to consider the BOS recommendation for comments to PHMSA regarding their proposal to its regulations concerning natural gas and hazardous liquid pipelines. Comments need to be complete for the BOS meeting on 3/17/20 in order to be submitted by 4/6/2020. Caroline will send out a google doc to the TF for comments prior to the meeting.
   There was discussion about advocating to Houlihan's office for more stringent regulations regarding hazardous volatile liquids. Michele stated she will reach out to one of her contacts.

Old Business

1. **Boot Road Geophysical Survey Reports** and **Right to Know Request** – Rick reported that a Right to Know was filed to PennDOT for additional information about the Boot Road Geophysical Survey Reports. Once the Township receives the information, it will be forwarded to Pennoni for review. Rick estimated the timeline to be mid-March.

Christina reported that she also filed a Right to Know request. She explained that she plans to inspect the records in person. Christina added that she emailed Rettew and has not received a response.

2. **Hiring of geologist consultant** – Rick reported that the BOS has agreed to have a geologist from Pennoni review the Boot Road info.
3. **HDD S3-500 Re-Evaluation Report** - Rick explained that the drilling method of using steel casings is being implemented at HDD S3-500 (New Kent/Bow Tree). He continued that this should minimize the risk of an IR. He noted that he suggested this method in the public comments to the DEP. Christina explained that she also requested in the public comment for steel casing implementation to eliminate movement in the fracture zones.

   Christina expressed concern that the steel casing being added was a change by Sunoco that was done with no documentation or proper amendment. Rick explained that the addition of the casing does not change the method of drilling. Christina stated that she will contact the Clean Air Council.

   There was discussion about the curvature angle the pipeline takes at the New Kent location.
4. **Pipeline TF Accomplishments/Objectives Follow up** - Bill explained that he reported at the 1/28/20 ABC meeting. Rick added that the BOS will be reviewing the ABC objectives at the 3/3/20 board meeting and will provide feedback.
5. **Ongoing contact with Planning Commission and other EGT Committees** – Rick will reach out to Mark Gordon about adding to their 3/4/20 agenda the development of a pipeline ordinance. He stated that the CCATO model ordinance would be a starting point for them.

Adjournment

The meeting was adjourned at 7:01 p.m.

The next workshop meeting is Thursday, March 12, 2020, at 5:00 pm.

Respectfully submitted,

Susan D'Amore

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Memo
East Goshen Township

Date: March 3, 2020
To: Pipeline Task Force
From: Rick Smith, Township Manager
Re: PHMSA – Notice of Proposed Rule Making (NPRM)
Docket Number PHMAS-2013-0255
Pipeline Safety: Valve Installation and Minimum Rupture Detection Standards

Pursuant to the NPRM published in the Federal Register published on February 6, 2020 I would offer the following comments.

Part 192 – Transportation of Natural Gas.

§192.3 Definitions

Comment - The definition of "rupture" appears to be appropriate.

§192.179 (e) Transmission Line Valves

Comment – There should be some provision to require the installation of these valves on existing pipelines over some period of time.

§192.610 Change in Class Location.

Comment – There should be some provision to require the additional valves to be installed on existing pipelines when there is a change in class location.

§192.615 (a)(6) Emergency Plans

Comment – As written requirement to identify a rupture does not apply to existing pipelines. Section should be reworded to apply to all pipelines.

§192.617 (c) & (d) Investigation of failures and incidents

Comment - As written these provisions only apply to ruptures and the closure of a rupture- mitigation valve. These section should be reworded to apply to all pipeline incidents.

§192.634 Transmission Lines

Comment – There should be some provision to require the installation of these valves on existing pipelines of some period of time.

Comment – If they replace 2 or more contiguous mile of pipeline are they required to install these valves on the entire pipeline segment, or just within the section of pipeline that has been replaced?

<u>Part 195 – Transportation of Hazardous Liquids by Pipeline</u>

§195.2 Definitions

Comment - The definition of "rupture" appears to be appropriate.

§ 195.258 (c) Valves: General

Comment – There should be some provision to require the installation of these valves on existing pipelines of some period of time.

§195.260 (c) Valves: Location

Comment – There should be some provision to require the installation of these valves on existing pipelines over some period of time.

Comment – If they replace 2 or more contiguous mile of pipeline are they requires to install these valves on the entire pipeline segment, or just within the section of pipeline that has been replaced.

§195.402(c) (5) Procedural manual of operations, maintenance, and emergencies.

Comment - As written these provisions only apply to ruptures and the closure of a rupture- mitigation valve. These section should be reworded to apply to all pipeline incidents.

§195.402(e) (4) Procedural manual of operations, maintenance, and emergencies.

Comment – As written requirement to identify a rupture within 10 minutes of the initial notification does not apply to existing pipelines. Section should be reworded to apply to all pipelines.

§195.418 Valves: Onshore valve Shut-off for rupture mitigation.

Comment – There should be some provision to require the installation of these valves on existing pipelines over some period of time.

§195.420(d) Valve Maintenance

Comment – This section should be revised to require point to point verification is required for all valves.

§195.420(e) Valve Maintenance

Comment – This section should be revised to that all valve can be closed within the 40 minute response time.

§195.452 (i)(4) Pipeline integrity management in high consequence areas.

Comment – If they replace 2 or more contiguous mile of pipeline are they required to install these valves on the entire pipeline segment, or just within the section of pipeline that has been replaced?

Abstract: This NPRM proposes a new paragraph (d) in both 49 CFR 192.634 and 195.418 requiring operators who elect to use alternative equivalent technology to notify, in accordance with 192.949, the Office of Pipeline Safety at least 90 days in advance of use. An operator choosing this option must include a technical and safety evaluation, including design, construction, and operating procedures for the alternative equivalent technology to the Associate Administrator of Pipeline Safety with the notification. PHMSA would then have 90 days to object to the alternative equivalent technology via letter from the Associate Administrator of Pipeline Safety; otherwise, the alternative equivalent technology would be acceptable for use. PHMSA estimates this notification requirement will result in 2 responses annually and has allotted each respondent 40 hours per response to conduct this task. PHMSA does not currently have an information collection that covers this requirement and will request the approval of this new collection, along with a new OMB Control Number, from the Office of Management and Budget.

Affected Public: Operators of PHMSA-regulated pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 2.

Total Annual Burden Hours: 80.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill, Office of Pipeline Safety (PHP–30), Pipeline and Hazardous Materials Safety Administration, 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, Telephone: 202–366–1246.

Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques.

(e) Ways the collection of this information is beneficial or not beneficial to public safety.

Send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW, Washington, DC 20503. Comments should be submitted on or prior to April 6, 2020.

I. Unfunded Mandates Reform Act of 1995

The analysis PHMSA performed in accordance with preparing the Preliminary Regulatory Impact Assessment does not expect this NPRM to impose unfunded mandates per the Unfunded Mandates Reform Act of 1995. It is not expected to result in costs of $100 million, adjusted for inflation, or more in any one (1) year to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the proposed rulemaking. A copy of the Preliminary Regulatory Impact Assessment is available for review in the docket.

J. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement, published on April 11, 2000 (65 FR 19476), in the **Federal Register** at: *https://www.govinfo.gov/content/FR-2000-04-11/pdf/00-8505.pdf.*

K. Regulation Identifier Number

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN contained in the heading of this document may be used to cross-reference this action with the Unified Agenda.

List of Subjects

49 CFR Part 192

Gas, Incorporation by reference, Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

49 CFR Part 195

Anhydrous ammonia, Carbon dioxide, Incorporation by reference, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, PHMSA proposes to amend 49 CFR parts 192 and 195 as follows:

PART 192—TRANSPORTATION OF NATURAL GAS AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 1. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 et. seq., and 49 CFR 1.97.

■ 2. In § 192.3, the definition of "rupture" is added in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

Rupture means any of the following events that involve an uncontrolled release of a large volume of gas:

(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 defined in paragraphs (2) or (3) of this definition;

(2) An unanticipated or unplanned 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 pressure loss the need for a higher pressure-change threshold due to pipeline flow dynamics that cause fluctuations in gas demand that are typically higher than a 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.

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

* * * * *

■ 3. In § 192.179, paragraph (e) is added to read as follows:

§ 192.179 Transmission line valves.

* * * * *

(e) All onshore transmission line segments with diameters greater than or equal to 6 inches that are constructed or entirely replaced after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE] must have automatic shutoff valves, remote-control valves, or equivalent technology installed at intervals 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 manual valve must notify PHMSA in accordance with the procedure in § 192.634(h). All valves and technology installed under this paragraph must meet the requirements of § 192.634(c), (d), (f), and (g).

■ 4. Section 192.610 is added to read as follows:

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

If a class location change on a transmission line occurs after [EFFECTIVE DATE OF FINAL RULE] and results in pipe replacement 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 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).

■ 5. In § 192.615, paragraphs (a)(2), (6), (8), and (11), and paragraph (c) introductory text are revised to read as follows:

§ 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, 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.

* * * * *

(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 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 evaluate and identify a 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 but within 10 minutes of the initial notification to or by the operator, regardless of how the rupture is initially detected or observed.

* * * * *

(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 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.

* * * * *

(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.

* * * * *

(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 public officials to:

* * * * *

■ 6. Section 192.617 is revised to read as follows:

§ 192.617 Investigation of failures and incidents.

(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.

(c) *Analysis of rupture and valve shut-offs; preventive and mitigative measures.* If a failure or incident involves a rupture 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 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.

■ 7. Section 192.634 is added to read as follows:

§ 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 constructed or where 2 or more contiguous miles have been replaced after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE], an operator must install rupture-mitigation valves according to the requirements of this section. Rupture-mitigation valves must be operational within 7 days of placing the new or replaced pipeline segment in service.

(b) *Maximum spacing between valves.* Rupture-mitigation valves must be installed in accordance with the following requirements:

(1) *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 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)(1)(i), (ii), or (iii).

(2) *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 must not exceed 15 miles.

(3) *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 must not exceed 8 miles.

(4) *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.

(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.

(d) *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 (c) of this section to mitigate the volume and consequence of gas released.

(e) *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 40 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 40-minute total response time in paragraph (c)(1) of this section.

(f) *Valve monitoring and operation capabilities.* Onshore transmission line rupture-mitigation valves actuated by methods in paragraph (e) 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;

(3) Monitored for valve status (*i.e.,* open, closed, or partial closed/open), upstream pressure, and downstream pressure. Pipeline segments that use manual valve operation must have the capability to monitor pressures and 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.

(g) *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.

(h) *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.

■ 8. In § 192.745 paragraphs (c), (d), and (e) are added to read as follows:

§ 192.745 Valve maintenance: Transmission lines.

* * * * *

(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).

(d) For each rupture-mitigation valve under § 192.634 that is manually or locally operated:

(1) Operators must establish the 40-minute total response time as required by § 192.634 through an initial drill and through periodic validation as required in paragraph (d)(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 following rupture identification.

(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 40-minute total response time validation drill that simulates 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.

(3) If the 40-minute maximum response time cannot be validated or achieved in the drill, the operator must revise response efforts to achieve compliance with § 192.634 no later than 6 months after the drill. Alternative valve shut-off measures must be in place in accordance with paragraph (e) 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.

(e) 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 shut-off, as follows:

(1) Repair or replace the valve as soon as practicable but no later than 6 months after finding that the valve is inoperable or unable to maintain shut-off; and

(2) Designate an alternative compliant valve within 7 calendar days of the finding while repairs are being made.

■ 9. In § 192.935, paragraph (c) is revised to read as follows:

§ 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 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.

(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.

* * * * *

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 10. The authority citation for part 195 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et seq.*, and 49 CFR 1.97.

■ 11. In § 195.2, the definition for "rupture" is added in alphabetical order to read as follows:

§ 195.2 Definitions.

* * * * *

Rupture means 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.

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

* * * * *

■ 12. In § 195.258, paragraph (c) is added to read as follows:

§ 195.258 Valves: General.

* * * * *

(c) All onshore hazardous liquid or carbon dioxide pipeline segments with diameters greater than or equal to 6 inches that are constructed or entirely replaced after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE] must have automatic shutoff valves, remote-control valves, or equivalent technology installed at intervals meeting the appropriate valve location and spacing requirements of this section and § 195.260. 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 installing alternative equivalent technology or manual valves must notify PHMSA in accordance with the procedure at § 195.418(h). Valves and technology installed under this section must meet the requirements of § 195.418(c), (d), (f), and (g).

■ 13. In § 195.260, paragraphs (c) and (e) are revised and paragraphs (g) and (h) are added to read as follows:

§ 195.260 Valves: Location.

* * * * *

(c) On each mainline at locations along the pipeline system that will minimize or prevent safety risks, property damage, or environmental harm from accidental hazardous liquid or carbon dioxide discharges, as appropriate for onshore areas, offshore areas, or high consequence areas. For onshore pipelines constructed or that have had 2 or more contiguous miles replaced after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE], mainline valve spacing must not exceed 15 miles for pipeline segments that could affect high consequence areas (as defined in § 195.450) and 20 miles for pipeline segments that could not affect high consequence areas. Valves protecting high consequence areas must be located as determined by the operator's process for identifying preventive and mitigative measures established in § 195.452(i) and by using a process, such as is set forth in Section I.B of Appendix C of part 195, but with a maximum distance from the high consequence area segment endpoints that does not exceed 7½ miles.

* * * * *

(e) On each side of a water crossing that is more than 100 feet (30 meters) wide from high-water mark to high-water mark as follows, unless the Associate Administrator finds under paragraph (e)(3) of this section that valves or valve spacing is not necessary in a particular case to achieve an equivalent level of safety:

(1) Valves must either be located outside of the flood plain or have valve actuators and other control equipment installed to not be impacted by flood conditions; and

(2) For multiple water crossings, valves must be located on the pipeline upstream and downstream of the first and last water crossings so that the total distance between the first upstream valve and last downstream valve does not exceed 1 mile.

(3) An operator may notify PHMSA in accordance with paragraph (h) of this section if in a particular case the valves or valve spacing required by this paragraph is not necessary to achieve an equivalent level of safety. Unless the Associate Administrator finds in that particular case the valves or valve spacing required by this paragraph are not necessary to achieve an equivalent level of safety, the operator must comply with the valve and valve spacing requirements of this paragraph.

* * * * *

(g) On each mainline highly volatile liquid (HVL) pipeline that is located in a high population area or other populated area as defined in § 195.450 and that is constructed or that has 2 or more contiguous miles replaced after [DATE 12 MONTHS AFTER EFFECTIVE DATE OF FINAL RULE], with a maximum valve spacing of 7½ miles, unless the Associate Administrator finds in a particular case that this valve spacing is not necessary to achieve an equivalent level of safety. An operator may notify PHMSA in accordance with paragraph (h) of this section if in a particular case the valve spacing required by this paragraph is not necessary to achieve an equivalent level of safety. If the Associate Administrator informs an operator that PHMSA objects, the operator must comply with the valve spacing requirements of this paragraph.

(h) An operator must provide any notification required by this section by:

(1) Sending the notification by electronic mail to *InformationResourcesManager@dot.gov;* or

(2) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, 1200 New Jersey Ave. SE, Washington, DC 20590.

■ 14. In § 195.402, paragraphs (c)(4), (5), and (12), and (e)(1), (4), (7), and (10) are revised to read as follows:

§ 195.40 2 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(c) * * *

(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).

(5) Investigating and analyzing pipeline accidents and failures, 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 and minimize the possibility of a recurrence.

(i) *Post-incident lessons learned.* Each operator must develop, implement, and incorporate lessons learned from a post-accident review into its procedures, including in pertinent operator personnel training and qualifications programs and in design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

(ii) *Analysis of rupture and valve shut-offs; preventive and mitigative measures.* If a failure or accident involves a rupture as defined in § 195.2 or a rupture-mitigation valve closure as defined in § 195.418, the operator must also conduct a post-accident 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:

(A) Detection, identification, operational response, system shut-off, and emergency-response communications, based on the type and volume of the release or failure event;

(B) Appropriateness and effectiveness of procedures and pipeline systems, including SCADA, communications, valve shut-off, and operator personnel;

(C) Actual response time from rupture identification to initiation of mitigative actions, and the appropriateness and effectiveness of the mitigative actions taken;

(D) Location and the timeliness of actuation of all rupture-mitigation valves identified under § 195.418; and

(E) All other factors the operator deems appropriate.

(iii) *Rupture post-incident summary.* If a failure or incident involves a rupture as defined in § 195.2 or the closure of a rupture-mitigation valve as defined in § 195.418, the operator must complete a summary of the post-accident review required by paragraph (c)(5)(ii) 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.

* * * * *

(12) 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, 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.

* * * * *

(e) * * *

(1) Receiving, identifying, and classifying notices of events that need immediate response by the operator or notice to the appropriate public safety answering point (9–1–1 emergency call center), as well as fire, police, and other appropriate public officials, and communicating this information to appropriate operator personnel for corrective action.

* * * * *

(4) 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 to minimize hazards of released hazardous liquid or carbon dioxide to life, property, or the environment. Each operator installing valves in accordance with § 195.258(c) or subject to the requirements in § 195.418 must also evaluate and identify a rupture as defined in § 195.2 as being an actual rupture event or non-rupture event in accordance with operating procedures as soon as practicable but within 10 minutes of the initial notification to or by the operator, regardless of how the rupture is initially detected or observed.

* * * * *

(7) Notifying the appropriate public safety answering point (9–1–1 emergency call center), as well as fire, police, and other public officials, of hazardous liquid or carbon dioxide pipeline emergencies to coordinate and share information to determine the location of the release, including both planned responses and actual responses during an emergency, and any additional precautions necessary for an emergency involving a pipeline transporting a highly volatile liquid. 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.

* * * * *

(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.

* * * * *

■ 15. Section 195.418 is added to read as follows:

§ 195.418 Valves: Onshore valve shut-off for rupture mitigation.

(a) *Applicability.* For onshore pipeline segments that could affect high consequence areas with nominal diameters of 6 inches or greater, that are constructed or where 2 or more contiguous miles are replaced after [DATE 12 MONTHS AFTER THE EFFECTIVE DATE OF THE RULE], an operator must install rupture-mitigation valves according to the requirements of this section and § 195.260. Rupture-mitigation valves must be operational within 7 days of placing the new or replaced pipeline segment in service.

(b) *Maximum spacing between valves.* Rupture-mitigation valves must be installed in accordance with the following requirements:

(1) For purposes of this section, a "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 segment that could affect the high consequence area

is between at least two rupture-mitigation valves. If any crossover or lateral pipe for commodity receipts or deliveries connects to the shut-off segment between the upstream and downstream mainline valves, 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 commodity to be transported to the rupture site (except for residual liquids 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. 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 of this section. The distance between rupture-mitigation valves in high consequence areas for each shut-off segment must not exceed 15 miles, with a maximum distance not to exceed 7½ miles from the endpoints of a shut-off segment. Valves on lines carrying highly volatile liquids in high population areas and other populated areas, as those terms are defined in § 195.450, must have rupture-mitigation valves spaced at a maximum distance not exceeding 7½ miles.

(2) Lateral lines to shut-off segments that contribute less than 5 percent of the total shut-off segment commodity volume may have lateral 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 hazardous liquid or carbon dioxide volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment commodity volume based upon maximum flow gradients and terrain.

(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 that 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.

(d) *Valve shut-off capability.* Onshore 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 (c) of this section to mitigate the volume and consequence of hazardous liquid or carbon dioxide released.

(e) *Valve shut-off methods.* All onshore rupture-mitigation valves must be actuated by one of the following methods to mitigate a rupture as soon as practicable but within 40 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 an 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 § 195.258 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, 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 a 40-minute total response time in paragraph (c)(1) of this section.

(f) *Valve monitoring and operation capabilities.* Onshore rupture-mitigation valves actuated by methods in paragraph (e) 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;

(3) Monitored for valve status (*i.e.,* open, closed, or partial closed/open), upstream pressure, and downstream pressure. Pipeline segments that use manual valve operation must have the capability to monitor pressures and 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)(1) 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.

(g) *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.

(h) *Alternative equivalent technology or manual valves for onshore rupture mitigation.* If an operator elects to use alternative equivalent technology or manual valves in accordance with § 195.258(c), the operator must notify PHMSA at least 90 days in advance of installation or use in accordance with § 195.452(m). 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 in lieu of a manual valve 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.

16. In § 195.420, paragraph (b) is revised and paragraphs (d), (e), and (f) are added to read as follows:

§ 195.420 Valve maintenance.

* * * * *

(b) Each operator must, at intervals not exceeding 7½ months but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly. Each valve installed under § 195.258(c) or rupture-mitigation valve, as defined under § 195.418, must also be partially operated as part of the inspection.

* * * * *

(d) For each valve installed under § 195.258(c) or onshore rupture-mitigation valve identified under § 195.418 that is remote-control shut-off, automatic shut-off, 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 § 195.446(c) and (e), or perform an equivalent verification.

(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.

(3) If the 40-minute maximum response time cannot be validated or achieved in the drill, the operator must revise response efforts to achieve compliance with § 195.418 no later than 6 months after the drill. Alternative valve shut-off measures must be in accordance with paragraph (f) of this section within 7 days of the 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.

(iii) Any other areas identified by the operator as needing improvement.

(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.

■ 17. In § 195.452, paragraph (i)(4) is revised to read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

* * * * *

(i) * * *

(4) *Emergency Flow Restricting Devices (EFRD).* If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors—the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size.

(i) Where EFRDs are installed to protect HCAs on all onshore pipelines with diameters of 6 inches or greater and that are placed into service or that have had 2 or more contiguous miles of pipe replaced after [insert date 12 months after effective date of this rule], the location, installation, actuation, operation, and maintenance of such EFRDs (including valve actuators, personnel response, operational control centers, SCADA, communications, and procedures) must meet the design, operation, testing, maintenance, and rupture mitigation requirements of §§ 195.258, 195.260, 195.402, 195.418, and 195.420.

(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.

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Alan K. Mayberry,

Associate Administrator for Pipeline Safety.

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