DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 195

[Docket No. PHMSA–2010–0229]

RIN 2137–AE66

Pipeline Safety: Safety of Hazardous Liquid Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking.

SUMMARY: In recent years, there have been significant hazardous liquid pipeline accidents, most notably the 2010 crude oil spill near Marshall, Michigan, during which almost one million gallons of crude oil were spilled into the Kalamazoo River. In response to accident investigation findings, incident report data and trends, and stakeholder input, PHMSA published an Advance Notice of Proposed Rulemaking (ANPRM) in the **Federal Register** on October 18, 2010. The ANPRM solicited stakeholder and public input and comments on several aspects of hazardous liquid pipeline regulations being considered for revision or updating in order to address the lessons learned from the Marshall, Michigan accident and other pipeline safety issues. Subsequently, Congress enacted the Pipeline Safety, Regulatory Certainty, and Job Creation Act that included several provisions that are relevant to the regulation of hazardous liquid pipelines. Shortly after the Pipeline Safety, Regulatory Certainty, and Job Creation Act was passed, the National Transportation Safety Board (NTSB) issued its accident investigation report on the Marshall, Michigan accident. In it, NTSB made additional recommendations regarding the need to revise and update hazardous liquid pipeline regulations.

In response to these mandates, recommendations, lessons learned, and public input, PHMSA is proposing to make changes to the hazardous liquid pipeline safety regulations. PHMSA is proposing these changes to improve protection of the public, property, and the environment by closing regulatory gaps where appropriate, and ensuring that operators are increasing the detection and remediation of unsafe conditions, and mitigating the adverse effects of pipeline failures.

DATES: Persons interested in submitting written comments on this NPRM must do so by January 8, 2016. PHMSA will consider late filed comments so far as practicable.

ADDRESSES: You may submit comments identified by the docket number PHMSA–2010–0229 by any of the following methods:

Federal eRulemaking Portal: http://www.regulations.gov. Follow the online instructions for submitting comments. Fax: 1–202–493–2251.

Mail: Hand Delivery: U.S. DOT Docket Management System, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590–0001, between 9 a.m. and 5 p.m., Monday through Friday, except federal holidays.

Instructions: If you submit your comments by mail, submit two copies. To receive confirmation that PHMSA received your comments, include a self-addressed stamped postcard.

Note: Comments are posted without changes or edits to *http://www.regulations.gov,* including any personal information provided. There is a privacy statement published on *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Mike Israni, by telephone at 202–366–4571, by fax at 202–366–4566, or by mail at U.S. DOT, PHMSA, 1200 New Jersey Avenue SE., PHP–30, Washington, DC 20590–0001.

SUPPLEMENTARY INFORMATION:

Outline of this document:

I. Executive Summary

In recent years, there have been significant hazardous liquid pipeline accidents, most notably the 2010 crude oil spill near Marshall, Michigan, during which almost one million gallons of crude oil were spilled into the Kalamazoo River. In response to accident investigation findings, incident report data and trends, and stakeholder input, PHMSA published an ANPRM in the **Federal Register** on October 18, 2010, (75 FR 63774). The ANPRM solicited stakeholder and public input and comments on several aspects of hazardous liquid pipeline regulations being considered for revision or updating in order to address the lessons learned from the Marshall, Michigan accident and other pipeline safety issues.

Subsequently, Congress enacted the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112–90) (The Act). That legislation included several provisions that are relevant to the regulation of hazardous liquid pipelines. Shortly after the Act was passed, NTSB issued its accident investigation report on the Marshall, Michigan accident. In it, NTSB made additional recommendations regarding the need to revise and update hazardous liquid pipeline regulations. Specifically, the NTSB issued recommendations P–12–03 and P–12–04 respectively, which addressed detection of pipeline cracks and ‘‘discovery of condition’’. The ‘‘discovery of condition’’ recommendation would require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators notify the Pipeline and Hazardous Materials Safety Administration and provide an expected date when adequate information will become available.

The Government Accounting Office (GAO) also issued a recommendation in 2012 concerning hazardous liquid and gas gathering pipelines. Recommendation GAO–12–388, dated March 22, 2012, states ‘‘To enhance the safety of unregulated onshore hazardous liquid and gas gathering pipelines, the Secretary of Transportation should direct the PHMSA Administrator to collect data from operators of federally unregulated onshore hazardous liquid and gas gathering pipelines, subsequent to an analysis of the benefits and industry burdens associated with such data collection’’.

In response to these mandates, recommendations, lessons learned, and public input, PHMSA is proposing to make certain changes to the Hazardous Liquid Pipeline Safety Regulations. The first and second proposals are to extend reporting requirements to all hazardous liquid gravity and gathering lines. The collection of information about these lines is authorized under the Pipeline Safety Laws, and the resulting data will assist in determining whether the existing federal and state regulations for these lines are adequate.

The third proposal is to require inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events. Such inspections will ensure that pipelines are still capable of being safely operated after these events. The fourth proposal is to require periodic inline integrity assessments of hazardous liquid pipelines that are located outside of HCAs. HCA's are already covered under the IM program requirements. These assessments will provide critical information about the condition of these pipelines, including the existence of internal and external corrosion and deformation anomalies.

The fifth proposal is to require the use of leak detection systems on hazardous liquid pipelines in all locations. The use of such systems will help to mitigate the effects of hazardous liquid pipeline failures that occur outside of HCAs. The sixth proposal is to modify the provisions for making pipeline repairs. Additional conservatism will be incorporated into the existing repair criteria and an adjusted schedule will be established to provide greater uniformity. These criteria will also be made applicable to all hazardous liquid pipelines, with an extended timeframe for making repairs outside of HCAs.

The seventh proposal is to require that all pipelines subject to the IM requirements be capable of accommodating inline inspection tools within 20 years, unless the basic construction of a pipeline cannot be modified to permit that accommodation. Inline inspection tools are an effective means of assessing the integrity of a pipeline and broadening their use will improve the detection of anomalies and prevent or mitigate future accidents in high-risk areas. Finally, other regulations will be clarified to improve certainty and compliance. PHMSA estimates that 421 hazardous liquid operators may incur costs to comply with the proposed rule. The estimated annual costs for the different requirements range from approximately $1,000 to $16.7 million, with aggregate costs of approximately $22.4 million. These wide ranges exist because the requirements vary widely. For example, some requirements apply only to pipelines within HCAs, some only to those outside HCAs, and some to both; other requirements apply only to onshore pipelines, and others to both on- and offshore; the length of pipeline, and the number of operators affected both vary for the different requirements. These proposals are designed to mitigate or prevent some number of hazardous liquid pipeline incidents resulting in annualized benefits estimated between approximately $3.5 and $17.7 million, depending on the requirement. Factors such as increased safety, public confidence that all pipelines are regulated, quicker discovery of leaks and mitigation of environmental damages, and better risk management are considered in this analysis. The dollar value of fatalities, injuries, and property damages due to pipeline incidents are societal costs and their prevention represents potential benefits. The changes proposed in this Notice of Proposed Rulemaking (NPRM) are expected to enhance overall pipeline safety and protection of the environment.

II. Background and NPRM Proposals

Congress established the current framework for regulating the safety of hazardous liquid pipelines in the Hazardous Liquid Pipeline Safety Act (HLPSA) of 1979 (Pub. L. 96–129). Like its predecessor, the Natural Gas Pipeline Safety Act (NGPSA) of 1968 (Pub. L. 90–481), the HLPSA provides the Secretary of Transportation (Secretary) with the authority to prescribe minimum federal safety standards for hazardous liquid pipeline facilities. That authority, as amended in subsequent reauthorizations, is currently codified in the Pipeline Safety Laws (49 U.S.C. 60101 *et seq.*).

PHMSA is the agency within DOT that administers the Pipeline Safety Laws. PHMSA has issued a set of comprehensive safety standards for the design, construction, testing, operation, and maintenance of hazardous liquid pipelines. Those standards are codified in the Hazardous Liquid Pipeline Safety Regulations (49 CFR part 195).

Part 195 applies broadly to the transportation of hazardous liquids or carbon dioxide by pipeline, including on the Outer Continental Shelf, with certain exceptions set forth by statute or regulation. Performance-based safety standards are generally favored (*i.e.,* a particular objective is specified, but the method of achieving that objective is not). Risk management principles play a critical role in the IM requirements for HCA's.

PHMSA exercises primary regulatory authority over interstate hazardous liquid pipelines, and the owners and operators of those facilities must comply with safety standards in part 195. The states may submit a certification to regulate the safety standards and practices for intrastate pipelines. States certified to regulate their intrastate lines can also enter into agreements with PHMSA to serve as an agent for inspecting interstate facilities.

Most state pipeline safety programs are administered by public utility commissions. These state authorities must adopt the Pipeline Safety Regulations as part of a certification or agreement, but can establish more stringent safety standards for those intrastate pipeline facilities that they have responsibility to regulate. PHMSA cannot regulate the safety standards or practices for an intrastate pipeline facility if a state has a current certification to regulate such facilities.

Congress recently enacted the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Pub. L. 112–90) (The Act). That legislation included several provisions that are relevant to the regulation of hazardous liquid pipelines. As part of the rulemaking process, PHMSA presented proposed changes in response to this Act in an ANPRM published in the **Federal Register** on October 18, 2010, (75 FR 63774). This NPRM will, in the paragraphs that follow, describe each of the proposals PHMSA will make along with a statement of need for each and an explanation of how each of these proposals improve the pipeline safety regulations.

Extend Certain Reporting Requirements to All Gravity and Rural Hazardous Liquid Gathering Lines

Gravity lines; pipelines that carry product by means of gravity, are currently exempt from PHMSA regulations. Many gravity lines are short and within tank farms or other pipeline facilities; however, some gravity lines are longer and are capable of building up large amounts of pressure. PHMSA is aware of gravity lines that traverse long distances with significant elevation changes which could have significant consequences in the event of a release.

In order for PHMSA to effectively analyze safety performance and pipeline risk of gravity lines, PHMSA needs basic data about those pipelines. The agency has the statutory authority to gather data for all gravity lines (49 U.S.C. 60117(b)), and that authority was not affected by any of the provisions in the Pipeline Safety Act of 2011. Accordingly, PHMSA is proposing to add 49 CFR 195.1(a)(5) to require that the operators of all gravity lines comply with requirements for submitting annual, safety-related condition, and incident reports. PHMSA estimates that, at most, five hazardous liquid pipeline operators will be affected. Based on comments from API–AOPL to the ANPRM, 3 operators have approximately 17 miles of gravity fed pipelines. PHMSA estimated that proportionally 5 operators would have 28 miles of gravity-fed pipelines.

PHMSA is also proposing to extend the reporting requirements of part 195 to all hazardous liquid gathering lines. According to the legislative history, Congress originally opposed any regulation of rural gathering lines in the Hazardous Liquid Pipeline Safety Act of 1979 (Pub. L. 96–129) for policy reasons (*i.e.,* those lines did not present a significant risk to public safety to justify federal regulation based on the data available at that time). See S. REP. NO. 96–182 (May 15, 1979), reprinted in 1979 U.S.C.C.A.N. 1971, 1972. However, Congress eventually relaxed that prohibition in the Pipeline Safety Act of 1992 (Pub. L. 102–508) and authorized the issuance of safety standards for regulated rural gathering lines based on a consideration of certain factors and subject to certain exclusions. When PHMSA adopted the current requirements for regulated rural gathering lines, the agency made certain policy judgments in implementing those statutory provisions based on the information available at that time.

Recent data indicates, however, that PHMSA regulates less than 4,000 miles of the approximately 30,000 to 40,000 miles of onshore hazardous liquid gathering lines in the United States. That means that as much as 90 percent of the onshore gathering line mileage is not currently subject to any minimum federal pipeline safety standards. The NTSB has also raised concerns about the safety of hazardous liquid gathering lines in the Gulf of Mexico and its inlets, which are only subject to certain inspection and reburial requirements.[1]

Congress also ordered the review of existing state and federal regulations for hazardous liquid gathering lines in the Pipeline Safety Act of 2011, to prepare a report on whether any of the existing exceptions for these lines should be modified or repealed, and to determine whether hazardous liquid gathering lines located offshore or in the inlets of the Gulf of Mexico should be subjected to the same safety standards as all other hazardous liquid gathering lines. Based on the study titled ''Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Gathering Lines,''[2] that was performed by the Oak Ridge National Laboratory and published on May 8, 2015, PHMSA is proposing additional regulations to ensure the safety of hazardous liquid gathering lines.

In order for PHMSA to effectively analyze safety performance and pipeline risk of gathering lines, we need basic data about those pipelines. PHMSA has statutory authority to gather data for all gathering lines (49 U.S.C. 60117(b)), and that authority was not affected by any of the provisions in the Pipeline Safety Act of 2011. Accordingly, PHMSA is proposing to add § 195.1(a)(5) to require that the operators of all gathering lines (whether onshore, offshore, regulated, or unregulated) comply with requirements for submitting annual, safety-related condition, and incident reports.

In the ANPRM, PHMSA asked whether the agency should repeal or modify any of the exceptions for hazardous liquid gathering lines. Section 195.1(a)(4)(ii) states that part 195 applies to a ''regulated rural gathering line as provided in § 195.11.'' PHMSA adopted a regulation in a June 2008 final rule (73 FR 31634) that prescribed certain safety requirements for regulated rural gathering lines (*i.e.,* the filing of accident, safety-related condition and annual reports; establishing the maximum operating pressure according to § 195.406; installing line markers; and establishing programs for public awareness, damage prevention, corrosion control, and operator qualification of personnel).

The June 2008 final rule did not establish safety standards for all rural hazardous liquid gathering lines. Some of those lines cannot be regulated by statute (*i.e.,* 49 U.S.C. 60101(b)(2)(B) states that ''the definition of 'regulated gathering line' for hazardous liquid may not include a crude oil gathering line that has a nominal diameter of not more than 6 inches, is operated at low pressure, and is located in a rural area that is not unusually sensitive to environmental damage.'') and Congress did not remove this exemption in the 2011 Act. However, the 2011 Act did require that PHMSA review whether currently unregulated gathering lines should be made subject to the same regulations as other pipelines.

Require Inspections of Pipelines in Areas Affected by Extreme Weather, Natural Disasters, and Other Similar Events

In July 2011 a pipeline failure occurred near Laurel, Montana, causing the release of an estimated 1,000 barrels of crude oil into the Yellowstone River. That area had experienced extensive flooding in the weeks leading up to the failure, and the operator has estimated the cleanup costs at approximately $135 million. An instance of flooding also occurred in 1994 in the State of Texas, leading to the failure of eight pipelines and the release of more than 35,000 barrels of hazardous liquids into the San Jacinto River. Some of that released product also ignited, causing minor burns and other injuries to nearly 550 people according to the NTSB. As the agency has noted in a series of advisory bulletins, hurricanes are capable of causing extensive damage to both offshore and inland pipelines (*e.g.,* Hurricane Ivan, September 23, 2004 (69 FR 57135); Hurricane Katrina, September 7, 2004 (70 FR 53272); Hurricane Rita, September 1, 2011 (76 FR 54531)).

These events demonstrate the importance of ensuring that our nation's waterways are adequately protected in the event of a natural disaster or extreme weather. PHMSA is aware that responsible operators might do such inspections; however, because it is not a requirement, some operators do not. Therefore, PHMSA is proposing to require that operators perform an additional inspection within 72 hours after the cessation of an extreme weather event such as a hurricane or flood, an earthquake, a natural disaster, or other similar event.

Specifically, under this proposal an operator must inspect all potentially affected pipeline facilities post extreme weather event to ensure that no conditions exist that could adversely affect the safe operation of that pipeline. The operator would be required to consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the inspection required. The inspection must occur within 72 hours after the cessation of the event, or as soon as the affected area can be safely accessed by the personnel and equipment required to perform the inspection. PHMSA has found that 72 hours is reasonable and achievable in most cases. If an adverse condition is found, the operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection. Such actions might include, but are not limited to:

- Reducing the operating pressure or shutting down the pipeline;
- Modifying, repairing, or replacing any damaged pipeline facilities;
- Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-ways (ROWS);
- Performing additional patrols, surveys, tests, or inspections;
- Implementing emergency response activities with federal, state, or local personnel; and
- Notifying affected communities of the steps that can be taken to ensure public safety.

This proposal is based on the experience of PHMSA and is expected to increase the likelihood that safety

[1] *https://app.ntsb.gov/news/2010/100624b.html.*

[2] *http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_7B2B80704EBC3EBABDB5B9F701F184E0854F3600/filename/report_to_congress_on_gathering_lines.pdf.*

conditions will be found earlier and responded to more quickly. PHMSA invites comment on this and other proposals in this NPRM. In regard to this proposal, PHMSA has particular interest in additional comments concerning how operators currently respond to these events, what type of events are encountered and if a 72 hour response time is reasonable.

Require Periodic Assessments of Pipelines That Are Not Already Covered Under the IM Program Requirements

PHMSA is proposing to require assessments for pipeline segments in non-HCAs. PHMSA believes that expanded assessment of non-HCA pipeline segments areas will provide operators with valuable information they may not have collected if regulations were not in place such a requirement would ensure prompt detection and remediation of corrosion and other deformation anomalies in all locations, not just HCAs. Specifically, the proposed § 195.416 would require operators to assess non-HCA (non-IM) pipeline segments with an inline inspection (ILI) tool at least once every 10 years. PHMSA needs operators to complete assessments in HCAs followed by assessments in non-HCAs. Other assessment methods could be used if an operator provides the Office of Pipeline Safety (OPS) with prior written notice that a pipeline is not capable of accommodating an ILI tool. The written notice provided to PHMSA must include a technical demonstration of why the pipeline is not capable of accommodating an ILI tool and what alternative technology the operator proposes to use. The operator must also detail how the alternative technology would provide a substantially equivalent understanding of the pipeline's condition in light of the threats that could affect its safe operation. Such alternative technologies would include hydrostatic pressure testing or appropriate forms of direct assessment.

The individuals who review the results of these periodic assessments would need to be qualified by knowledge, training, and experience and would be required to consider any uncertainty in the results obtained, including ILI tool tolerance, when determining whether any conditions could adversely affect the safe operation of a pipeline. Such determinations would have to be made promptly, but no later than 180 days after an inspection, unless the operator demonstrates that the 180-day deadline is impracticable.

Operators would be required to comply with the other provisions in part 195 in implementing the requirements in § 195.416. That includes having appropriate provisions for performing these periodic assessments and any resulting repairs in an operator's procedural manual (see § 195.402), adhering to the recordkeeping provisions for inspections, test, and repairs (see § 195.404), and taking appropriate remedial action under § 195.422, as discussed below. Section 195.11 would also be amended to subject regulated onshore gathering lines to the periodic assessment requirement.

PHMSA believes by proposing the above amendment to the existing pipeline safety regulations, safety will be increased for all pipelines both in and out of HCAs. Such a requirement would ensure operators obtain information necessary for prompt detection and remediation of corrosion and other deformation anomalies in all locations, not just HCAs. Currently, operators have indicated that they are performing ILI assessments on a large majority of their pipelines even though no regulation requires them to do so outside of HCAs. PHMSA wants to ensure that current assessment rates continue and expand to those areas not voluntarily assessed. Of the many methods to assess, PHMSA has found that ILI in many cases is the most efficient and effective. PHMSA considered alternatives to its proposal that would likely have lower overall costs and benefits, but potentially higher net benefits. For instance, PHMSA considered limiting the proposed expansion of certain IM requirements to those pipelines where a spill could affect a building or occupied site such as a playground, or highway. Under this alternative, pipelines in a location where a spill could not affect a building, occupied site, or highway would not be subject to these new requirements. However, this alternative would offer less protection to the natural environment, including sensitive and protected habitats and species. PHMSA also considered alternative assessment intervals to the proposed 10 year interval, such as a 15- or 20-year interval. However, substantial changes to pipeline integrity can occur in a short timeframe. PHMSA declined to propose these alternatives because they would provide fewer benefits than the proposed approach. More specifically, liquid spills, even in remote areas, can result in environmental damage necessitating clean up and incurring restoration costs and lost use and nonuse values. If pipe is not assessed and repaired in accordance with this proposal, liquid spills are likely to occur.

Also, a longer interval between assessments would increase risks of integrity-related failure compared to PHMSA's proposal. PHMSA was unable to quantify the benefits and costs of these alternatives due to limitations in available information, such as the amount of unassessed pipe where a spill could not affect a building, occupied site, or highway; the environmental impact of spills from such pipe; and the incremental reduction in benefit between 10-year and alternative interval periods. PHMSA seeks public comments on these alternatives, and the regulatory impact analysis contains specific questions for public comment on quantifying these alternatives.

Modify the IM Repair Criteria and Apply Those Same Criteria to Any Pipeline Where the Operator Has Identified Repair Conditions

Inspection experience indicates a weakness in current repair criteria. Specifically, the current repair criteria in non-HCAs (immediate and reasonable time) does not specify anomaly or repair time frames. It is left entirely at the operator's discretion. Therefore, PHMSA is proposing to modify the IM pipeline repair criteria and to apply the criteria to non-IM pipeline repairs. Specifically, the criteria in § 195.452(h) for IM repairs would be modified to:

- Categorize bottom-side dents with stress risers as immediate repair conditions;
- Require immediate repairs whenever the calculated burst pressure is less than 1.1 times maximum operating pressure;
- Eliminate the 60-day and 180-day repair categories; and
- Establish a new, consolidated 270-day repair category.

PHMSA is also proposing to amend the requirements in § 195.422 for performing non-IM repairs by:

- Applying the criteria in the immediate repair category in § 195.452(h); and
- Establishing an 18-month repair category for hazardous liquid pipelines that are not subject to IM requirements.

PHMSA believes that these changes will ensure that immediate action is taken to remediate anomalies that present an imminent threat to the integrity of hazardous liquid pipelines in all locations. Moreover, many anomalies that would not qualify as immediate repairs under the current criteria will meet that requirement as a result of the additional conservatism that will be incorporated into the burst pressure calculations. The new time frames for performing non-immediate repairs will also allow operators to remediate those conditions in a timely manner while allocating resources to those areas that present a higher risk of harm to the public, property, and the environment. The existing requirements in § 195.422 would also be modified to include a general requirement for performing all other repairs within a reasonable time. A proposed amendment to § 195.11 would extend these new pipeline remediation requirements to regulated onshore gathering lines.

As a result of these changes, PHMSA would modify the existing general requirements for pipeline repairs in § 195.401(b). Paragraph (b)(1) would be modified to reference the new timeframes in § 195.422(d) and (e) for remediating conditions that could adversely affect the safe operation of a pipeline segment not subject to the IM requirements in § 195.452. The requirements in paragraph (b)(2) for IM repairs under § 195.452(h) will be retained without change. A new paragraph (b)(3) will be added, however, to require operators to consider the risk to people, property, and the environment in prioritizing the remediation of any condition that could adversely affect the safe operation of a pipeline system, including those covered by the timeframes specified in §§ 195.422(d) and (e) and 195.452(h).

Expand the Use of Leak Detection Systems for All Hazardous Liquid Pipelines

PHMSA is proposing to amend § 195.134 to require that all new hazardous liquid pipelines be designed to include leak detection systems. Recent pipeline accidents, including a pair of related failures that occurred in 2010 on a crude oil pipeline in Salt Lake City, Utah, corroborate the significance of having an adequate means for identifying leaks in all locations. PHMSA, aware of the significance of leak detection, held two recent workshops in Rockville, Maryland on March 27–28 of 2012. These workshops sought comment from the public concerning many of the issues raised in the 2010 ANPRM, including leak detection expansion. Both workshops were well attended and PHMSA received valuable input from stakeholders.

Currently, part 195 contains mandatory leak detection requirements for hazardous liquid pipelines that could affect an HCA.

Congress included additional requirements for leak detection systems in section 8 of the Pipeline Safety Act of 2011. That legislation requires the Secretary to submit a report to Congress, within 1-year of the enactment date, on the use of leak detection systems, including an analysis of the technical limitations and the practicability, safety benefits, and adverse consequence of establishing additional standards for the use of those systems. To provide Congress with an opportunity to review that report, the Secretary is prohibited from issuing any final leak detection regulations for a specified time period (*i.e.,* 2 years from the date of the enactment of the Pipeline Safety Act of 2011, or 1-year after the submission of the leak detection report to Congress, whichever is earlier), unless a condition exists that poses a risk to public safety, property, or the environment, or is an imminent hazard, and the issuance of such regulations would address that risk or hazard. Other provisions in part 195 help to detect and mitigate the effects of pipeline leaks, including the Right of Way (ROW).

In addition to modifying § 195.444 to require a means for detecting leaks on all portions of a hazardous liquid pipeline system, PHMSA is proposing that operators be required to have an evaluation performed to determine what kinds of systems must be installed to adequately protect the public, property, and the environment. The factors that must be considered in performing that evaluation would include the characteristics and history of the affected pipeline, the capabilities of the available leak detection systems, and the location of emergency response personnel. A proposed amendment to § 195.11 would extend these new leak detection requirements to regulated onshore gathering lines. PHMSA is retaining and is not proposing any modification to the requirement in §§ 195.134 and 195.444 that each new computational leak detection system comply with the applicable requirements in the API RP 1130 standard.

PHMSA does not propose to make any additional changes to the regulations concerning specific leak detection requirements at this time. PHMSA will be studying this issue further and may make proposals concerning this topic in a later rulemaking. PHMSA recently publicly provided the results of the 2012 Keifner and Associates study of leak detection systems in the pipeline industry, including the current state of technology.

Increase the Use of Inline Inspection Tools

PHMSA is proposing to require that all hazardous liquid pipelines in HCA's and areas that could affect an HCA be made capable of accommodating ILI tools within 20 years, unless the basic construction of a pipeline will not accommodate the passage of such a device.

The current requirements for the passage of ILI devices in hazardous liquid pipelines are prescribed in § 195.120, which require that new and replaced pipelines are designed to accommodate inline inspection tools. The basis for these requirements was a 1988 law that addressed the Secretary's authority with regard to requiring the accommodation of ILI tools. This law required the Secretary to establish minimum federal safety standards for the use of ILI tools, but only in newly constructed and replaced hazardous liquid pipelines (Pub. L. 100–561).

In 1996, Congress passed another law further expanding the Secretary's authority to require pipeline operators to have systems that can accommodate ILI tools. In particular, Congress provided additional authority for the Secretary to require the modification of existing pipelines whose basic construction would accommodate an ILI tool to accommodate such a tool and permit internal inspection (Pub. L. 104–304).

As the Research and Special Programs Administration (RSPA), (a predecessor agency of PHMSA) explained in the final rule April 12, 1994 (59 FR 17275) that promulgated § 195.120, ''[t]he clear intent of th[at] congressional mandate [wa]s to improve an existing pipeline's piggability,'' and to ''require[] the gradual elimination of restrictions in existing hazardous liquid and carbon dioxide lines in a manner that will eventually make the lines piggable.'' April 2, 1994, (59 FR 17279). RSPA also noted that Congress amended the 1988 law in the Pipeline Safety Act of 1992 (Pub. L. 102–508) to require the periodic internal inspection of hazardous liquid pipelines, including with ILI tools in appropriate circumstances April 2, 1994, (59 FR 17275). RSPA established requirements for the use of ILI tools in pipelines that could affect HCAs in the December 2000 IM final rule December 1, 2000, (65 FR 75378).

Section 60102(f)(1)(B) of the Pipeline Safety Laws allows the requirements for the passage of ILI tools to be extended to existing hazardous liquid pipeline facilities, provided the basic construction of those facilities can be modified to permit the use of smart pigs.

The current requirements apply only to new hazardous liquid pipelines and to line sections where the line pipe, valves, fittings, or other components are replaced. Exceptions are also provided for certain kinds of pipeline facilities, including manifolds, piping at stations and storage facilities, piping of a size that cannot be inspected with a commercially available ILI tool, and smaller diameter offshore pipelines.

PHMSA is proposing to use the authority provided in section 60102(f)(1)(B) to further facilitate the ''gradual elimination'' of pipelines that are not capable of accommodating smart pigs. PHMSA would limit the circumstances where a pipeline can be constructed without being able to accommodate a smart pig. Under the current regulation, an operator can petition the PHMSA Administrator for such an allowance for reasons of impracticability, emergencies, construction time constraints, and other unforeseen construction problems. PHMSA believes that an exception should still be available for emergencies and where the basic construction of a pipeline makes that accommodation impracticable, but that the other, less urgent circumstances listed in the regulation are no longer appropriate. Accordingly, the allowances for construction-related time constraints and problems would be repealed.

Modern ILI tools are capable of providing a relatively complete examination of the entire length of a pipeline, including information about threats that cannot always be identified using other assessment methods. ILI tools also provide superior information about incipient flaws (*i.e.,* flaws that are not yet a threat to pipeline integrity, but that could become so in the future), thereby allowing these conditions to be monitored over consecutive inspections and remediated before a pipeline failure occurs. Hydrostatic pressure testing, another well-recognized method, reveals flaws (such as wall loss and cracking flaws) that cause pipe failures at pressures that exceed actual operating conditions. Similarly, external corrosion direct assessment (ECDA) can identify instances where coating damage may be affecting pipeline integrity, but additional activities, including follow-up excavations and direct examinations, must be performed to verify the extent of that threat. ECDA also provides less information about the internal condition of a pipe than ILI tools.

As with new pipelines, operators will be allowed to petition the PHMSA Administrator for a finding that the basic construction, (*i.e.,* terrain or location, of a pipeline or an emergency) will not permit the accommodation of a smart pig.

Clarify Other Requirements

PHMSA is also proposing several other clarifying changes to the regulations that are intended to improve compliance and enforcement. First, PHMSA is proposing to revise paragraph (b)(1) of § 195.452 to correct an inconsistency in the current regulations. Currently, § 195.452(b)(2) requires that segments of new pipelines that could affect HCAs be identified before the pipeline begins operations and § 195.452(d)(1) requires that baseline assessments for covered segments of new pipelines be completed by the date the pipeline begins operation. However, § 195.452(b)(1) does not require an operator to draft its IM program for a new pipeline until one-year after the pipeline begins operation. These provisions are inconsistent as the identification could affect segments, and performance of baseline assessments are elements of the written IM program. PHMSA would amend the table in (b)(1) to resolve this inconsistency by eliminating the one-year compliance deadline for Category 3 pipelines. An operator of a new pipeline would be required to develop its written IM program before the pipeline begins operation.

A decade's worth of IM inspection experience has shown that many operators are performing inadequate information analyses (*e.g.,* they are collecting information, but not affording it sufficient consideration). Integration is one of the most important aspects of the IM program because it is used in identifying interactions between threats or conditions affecting the pipeline and in setting priorities for dealing with identified issues. For example, evidence of potential corrosion in an area with foreign line crossings and recent aerial patrol indications of excavation activity could indicate a priority need for further investigation. Consideration of each of these factors individually would not reveal any need for priority attention. PHMSA is concerned that a major benefit to pipeline safety intended in the initial rule is not being realized because of inadequate information analyses.

For this reason, PHMSA is proposing to add additional specificity to paragraph (g) by establishing a number of pipeline attributes that must be included in these analyses and to require explicitly that operators integrate analyzed information. PHMSA is also proposing that operators consider explicitly any spatial relationships among anomalous information. PHMSA supports the use of computer-based geographic information systems (GIS) to record this information. GIS systems can be beneficial in identifying spatial relationships, but analysis is required to identify where these relationships could result in situations adverse to pipeline integrity.

Second, PHMSA is proposing that operators verify their segment identification annually by determining whether factors considered in their analysis have changed. Section 195.452(b) currently requires that operators identify each segment of their pipeline that could affect an HCA in the event of a release but there is no explicit requirement that operators assure that their identification of covered segments remains current. As time goes by, the likelihood increases that factors considered in the original identification of covered segments may have changed. PHMSA believes that operators should periodically re-visit their initial analyses to determine whether they need to be updated. New HCAs may be identified. Construction activities or erosion near the pipeline could change local topography in a way that could cause product released in an accident to travel further than initially analyzed. Changes in agricultural land use could also affect an operator's analysis of the distance released product could be expected to travel. Changes in the deployment of emergency response personnel could increase the time required to respond to a release and result in a larger area being affected by a potential release if the original segment identification relied on emergency response to limit the transport of released product.

The change that PHMSA is proposing would not require that operators re-perform their segment analyses. Rather, it would require operators to identify the factors considered in their original analyses, determine whether those factors have changed, and consider whether any such change would be likely to affect the results of the original segment identification. If so, the operator would be required to perform a new analysis to validate or change the endpoints of the segments affected by the change.

Third, PHMSA is proposing to clarify, through the use of an explicit reference that the IM requirements apply to portions of ''pipelines'' other than line pipe. Unlike integrity assessments for line pipe, § 195.452 does not include explicit deadlines for completing the analyses of other facilities within the definition of ''pipeline'' or for implementing actions in response to those analyses. Through IM inspections, PHMSA has learned that some operators have not completed analyses of their non-pipe facilities such as pump stations and breakout tanks and have not implemented appropriate protective and mitigative measures.

Section 29 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 states that ''[i]n identifying and evaluating all potential threats to each pipeline segment pursuant to parts 192 and 195 of title 49, Code of Federal Regulations, an operator of a pipeline facility shall consider the seismicity of the area.'' While seismicity is already mentioned at several points in the IM program guidance provided in Appendix C of part 195, PHMSA is proposing to further comply with Congress's directive by including an explicit reference to seismicity in the list of risk factors that must be considered in establishing assessment schedules (§ 195.452(e)), performing information analyses (§ 195.452(g)), and implementing preventive and mitigative measures (§ 195.452(i)) under the IM requirements.

III. Analysis of Advance Notice of Proposed Rulemaking

On October 18, 2010, (75 FR 63774), PHMSA published an ANPRM asking the public to comment on several proposed changes to part 195. The ANPRM sought comments on:

- Scope of part 195 and existing regulatory exceptions;
- Criteria for designation of HCAs;
- Leak detection and emergency flow restricting devices;
- Valve spacing;
- Repair criteria outside of HCAs; and
- Stress corrosion cracking.

The ANPRM may be viewed at *http://www.regulations.gov* by searching for Docket ID PHMSA–2010–0229.

Twenty-one organizations and individuals submitted comments in response to the ANPRM. The individual docket item numbers are listed for each comment.

- Associations representing pipeline operators (trade associations)
  - American Petroleum Institute—Association of Oil Pipelines (API–AOPL) (PHMSA–2010–0229–0030)
  - Independent Petroleum Association of America (IPAA) (PHMSA–2010–0229–0024)
  - Canadian Energy Pipeline Association (CEPA) (PHMSA–2010–0229–0008)
  - Oklahoma Independent Petroleum Association (OIPA) (PHMSA–2010–0229–0018)
  - Texas Pipeline Association (TPA) (PHMSA–2010–0229–0011)
  - Louisiana Midcontinent Oil & Gas Association (LMOGA) (PHMSA–2010–0229–0018)
  - Texas Oil & Gas Association (TxOGA) (PHMSA–2010–0229–0022)
- Transmission and Distribution Pipeline Companies
  - TransCanada Keystone (PHMSA–2010–0229–0027)
- Government/Municipalities
  - Defense Logistics Agency (DLA) (PHMSA–2010–0229–0016)
  - Metro Area Water Utility Commission (MAWUC) (PHMSA–2010–0229–0031)
  - North Slope Borough (NSB) (PHMSA–2010–0229–0012)
- Pipeline Safety Regulators
  - National Association of Pipeline Safety Representatives (NAPSR) (PHMSA–2010–0229–0032)
- Citizens' Groups
  - Pipeline Safety Trust (PST) (PHMSA–2010–0229–0014)
  - Cook Inlet Regional Citizens Advisory Council (CRAC)) (PHMSA–2010–0229–0019)
  - The Wilderness Society (TWS) (PHMSA–2010–0229–0025)
  - National Resources Defense Council et al. (NRDC) (PHMSA–2010–0229–0021)
  - Alaska Wilderness League et al. (AKW) (PHMSA–2010–0229–0026)
- Citizens
  - Patrick Coyle (PHMSA–2010–0229–0002)
  - Marian J. Stec (PHMSA–2010–0229–0007)
  - Pamela A. Miller (PHMSA–2010–0229–0013)
  - Anonymous (PHMSA–2010–0229–0005) (The anonymous comment dealt with quality of drinking water and release permits under the Clean Water Act.

These topics are beyond the scope of PHMSA's jurisdiction and are not discussed further).

Comments are reviewed in the order the ANPRM presented questions for comment. PHMSA responses to the comments follow.

A. Scope of Part 195 and Existing Regulatory Exceptions

Comments

API–AOPL, LMOGA, TxOGA, and TransCanada Keystone expressed support for the gravity line exception. These commenters stated that gravity lines are short, pose little risk, and are usually located within other regulated facilities, such as tank farms. NAPSR did not support a complete repeal of this exception, suggesting there was no data to support such an action. NAPSR did suggest that the exception should not apply to ethanol pipelines, which are very susceptible to internal corrosion.

MAWUC indicated that gravity lines in HCAs should be regulated because of the sensitivity of these areas. MAWUC further stated that these lines (and other rural onshore gathering lines) contain contaminants that are not present in products carried by other pipelines, that these contaminants are dangerous to pipeline workers, and that the impact of releases from these pipelines on the environment is the same as releases from regulated pipelines.

Response

PHMSA does not, at this time, intend to repeal the exemption for gravity lines, but does propose to extend reporting requirements to all hazardous liquid gravity lines. The collection of information about these lines is authorized under the Pipeline Safety Laws, and the resulting data will assist in determining whether the existing federal and state regulations for these lines are adequate.

Rural Gathering Lines

Comments

PHMSA received a number of comments on whether to modify or repeal the requirements in § 195.1(a)(4). API–AOPL, LMOG, IPAA, OIPA, and TxOGA stated that the regulatory exception for rural gathering lines is appropriate and should not be repealed or modified. They indicated that these lines are the source of a small percentage of spills, and that gathering lines in populated areas and near navigable waterways are already subject to PHMSA regulation.

Among citizens' groups, TWS suggested that PHMSA should examine federal and state release data from all excepted pipelines and regulate those with release rates similar to currently regulated pipelines. PST supported expansion of the definition of gathering line to the extent statutorily possible to capture all lines. Similarly, CRAC, TWS, and AKW indicated the exception should be removed and regulation expanded to include produced water lines and production lines. TWS and AKW also stated that flow lines, which are currently defined by regulation as production facilities, should be reclassified and regulated as gathering lines.

The government/municipalities NSB and MAWUC also commented concerning the rural gathering line exception. NSB requested PHMSA place a high priority on removing the exception for gathering lines. MAWUC supported no gathering line exceptions in HCAs.

Citizen Miller commented that PHMSA should regulate production and produced water lines on Alaska's North Slope, because this area is very sensitive and includes pristine wetlands and fish and wildlife habitats of national and international importance. She further commented that river and coastline pipeline routes and crossings in the Arctic and subarctic Alaska are particularly of concern due to the rapid change in permafrost, as well as high rates of coastal erosion which greatly increases the environmental and human impacts of spills.

Response

PHMSA believes that the requirements of the Pipeline Safety Act of 2011 and concerns for adequate regulatory oversight can only be addressed if PHMSA obtains additional information about gathering lines. PHMSA has the statutory authority to gather data for all gathering lines (49 U.S.C. 60117(b)), and that authority was not affected by any of the provisions in the Pipeline Safety Act of 2011. Accordingly, PHMSA is proposing to amend 49 CFR 195.1(a)(5) to require that the operators of all gathering lines (whether onshore, offshore, regulated, or unregulated) comply with requirements for submitting annual, safety-related condition, and incident reports.

Carbon Dioxide Lines

In the ANPRM, PHMSA asked whether the agency should repeal or modify the regulatory exception for carbon dioxide pipelines used in the well injection and recovery production process. Section 195.1(b)(10) states that part 195 does not apply to the transportation of carbon dioxide downstream from the applicable following point:

(i) The inlet of a compressor used in the injection of carbon dioxide for oil recovery operations, or the point where recycled carbon dioxide enters the injection system, whichever is farther upstream; or

(ii) The connection of the first branch pipeline in the production field where the pipeline transports carbon dioxide to an injection well or to a header or manifold from which a pipeline branches to an injection well.

Comments

The trade associations, LMOGA, API–AOPL, OIPA, TxOGA, and IPAA, commented that PHMSA should not repeal the exception for carbon dioxide lines used in the well injection and recovery production process. They indicated the potential risk from a production facility carbon dioxide pipeline failure is low due to factors of low potential release volumes, rapid dispersion, and low potential for human exposure. NAPSR suggested the current exception is appropriate and noted that there is no data indicating the need for a repeal.

Response

The regulatory history shows that the exception in § 195.1(b)(10) is limited in scope and only applies to carbon dioxide pipelines that are directly used in the production of hazardous liquids. See June 12, 1994, (56 FR 26923) (stating in preamble to 1991 final rule that ''the exception is limited to lines downstream of where carbon dioxide is delivered to a production facility in the vicinity of a well site, rather than excepting all the CO2 lines in the broad expanses of a production field.''); January 21, 1994, (59 FR 3390) (stating in preamble to June 1994 that agency adopted amendment ''to clarify that the exception covers pipelines used in the injection of carbon dioxide for oil recovery operations.''). Congress has indicated that such facilities should not be subject to federal regulation, and none of the commenters supported a repeal or modification of this exception. Accordingly, PHMSA is not proposing to repeal or modify § 195.1(b)(10).

Offshore Lines in State Waters

In the ANPRM, PHMSA asked whether the agency should repeal or modify any of the exceptions for offshore pipelines in state waters.

Comments

TransCanada Keystone, an industry commenter, and the trade associations, API–AOPL, LMOGA and TxOGA, stated the current exception should not be changed. API–AOPL pointed out that PHMSA's jurisdiction lies only with the transportation of hazardous liquids, not hydrocarbon production areas of offshore operations. API–AOPL further stated that changing the state waters exception would unnecessarily add a duplicative layer of federal regulation.

The citizens' groups, TWS and AKW, supported removal of this exemption and increased enforcement in state waters. Likewise, among the government/municipality comments, NSB indicated that the regulations need to be expanded to include lines in offshore state waters. NSB expressed concerns with lack of state enforcement, high corrosion potential, and the sensitivity of the location of the offshore lines, such as those in the Beaufort and Chukchi Seas.

The prohibitions of the Pipeline Safety Act of 2011 do not affect PHMSA's authority to ensure the safety of offshore gathering lines under other statutory provisions, including if such a line is hazardous to life, property, or the environment (49 U.S.C. 60112)). PHMSA also notes that the generally-applicable limitation in section 60101(a)(22) of the Pipeline Safety Laws only applies to ''onshore production . . . facilities,'' and that the states may regulate such intrastate facilities (see *e.g.,* Tex. Admin. Code Title. 16, sec. 8.1(a)(1)(D)).

Response

Congress has indicated that additional federal safety standards may be warranted for offshore gathering lines. First, we would note that this does not include offshore production pipelines. Section 195.1(b)(5) states that part 195 does not apply to the: Transportation of hazardous liquid or carbon dioxide in an offshore pipeline in state waters where the pipeline is located upstream from the outlet flange of the following farthest downstream facility; the facility where hydrocarbons or carbon dioxide are produced; or the facility where produced hydrocarbons or carbon dioxide are first separated, dehydrated, or otherwise processed.

RSPA, a predecessor agency of PHMSA, adopted § 195.1(b)(5) in a June 1994 final rule June 28, 1994, (59 FR 33388). Before that time, part 195 only included an explicit exception for offshore production pipelines located on the Outer Continental Shelf. However, as explained in the preamble to the June 1994 final rule, RSPA believed that the same exception should be applied to all offshore production pipelines, including those located in state waters. Under the federal pipeline safety laws, the agency does not regulate production facilities at all. Section 21 of the Pipeline Safety Act of 2011 requires the Secretary to review the existing federal and state regulations for gathering lines and to submit a report to Congress with the results of that review. A study on these regulations, titled ''Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Lines,'' was performed by the Oak Ridge National Laboratory and was published on May 8, 2015. The Secretary is also required, if appropriate, to issue regulations subjecting hazardous liquid gathering lines located offshore and in the inlets of the Gulf of Mexico to the same safety standards that apply to all other hazardous gathering lines. Section 21 states that any such regulations cannot be applied to production pipelines or flow lines.

Congress also included a provision authorizing the collection of geospatial or technical data on transportation-related flow lines in section 12 of the Pipeline Safety Act of 2011. A transportation-related flow line is defined for purposes of that provision as ''a pipeline transporting oil off of the grounds of the well where it originated and across areas not owned by the producer, regardless of the extent to which the oil has been processed, if at all.'' Section 12 also states that nothing in that provision ''authorizes the Secretary to prescribe standards for the movement of oil through production, refining, or manufacturing facilities or through oil production flow lines located on the grounds of wells.''

Producer-Operated Pipelines on Outer Continental Shelf

In the ANPRM, PHMSA asked whether the agency should repeal or modify any of the exceptions for pipelines on the OCS.

Comments

TransCanada Keystone, an industry commenter, and the trade associations, API–AOPL, LMOGA, and TxOGA, stated that the current exceptions for pipelines on the OCS should remain unchanged. API–AOPL requested that PHMSA indicate what impact the Bureau of Ocean Energy Management, Regulation and Enforcement's (BOEMRE) recent publication regarding Safety and Environmental Management Systems (SEMS) has on transportation operators. API–AOPL expressed concern that joint jurisdiction, if created by the recent BOEMRE publication, would result in regulatory uncertainty.

NAPSR responded that the exceptions for pipelines on the OCS should not be changed as these lines are already regulated by the Department of Interior.

Response

Section 195.1(b)(6) states that part 195 does not apply to the transportation of hazardous liquid or carbon dioxide in a pipeline on the OCS where the pipeline is located upstream of the point at which operating responsibility transfers from a producting operator to a transporting operator. Section 195.1(b)(7) further provides that part 195 does not apply to a pipeline segment upstream (generally seaward) of the last valve on the last production facility on the OCS where a pipeline on the OCS is producer-operated and crosses into state waters without first connecting to a transporting operator's facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. A producing operator of a segment falling within this exception may petition the Administrator, under § 190.9 of this chapter, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance. These exceptions are designed to ensure that a single federal agency is responsible for regulating the safety of any given pipeline segment on the OCS (*i.e.,* the Department of Interior for producer-operated pipelines and PHMSA for transporter-operated pipelines). See final rule codifying 1976 Memorandum of Understanding (MOU) between the Departments of Transportation and Interior on the regulation of offshore pipelines in § 195.1 August 12, 1976 (41 FR 34040); direct final rule codifying 1996 MOU between the Departments of Transportation and Interior on the regulation of offshore pipelines in § 195.1 November 19, 1997 (62 FR 61692); and final rule clarifying regulation of producer-operated pipelines that cross the federal-state boundary in offshore waters without first connecting to a transporting-operator's facility on the OCS) August 5, 2003 (68 FR 46109).

None of the commenters supported the repeal or modification of § 195.1(b)(6) or (7). Accordingly, PHMSA is not proposing to take any further action with respect to these two provisions. It should also be noted that PHMSA is not responsible for administering another federal agency's statutes or regulations.

Breakout Tanks Not Used for Reinjection or Continued Transportation

In the ANPRM, PHMSA asked for comment on whether the agency should expand the extent to which part 195 applies to breakout tanks.

Comments

PHMSA received several comments on whether the agency should expand the extent to which part 195 applies to breakout tanks. API–AOPL, supported by the industry commenter, TransCanada Keystone, and the trade associations, LMOGA and TxOGA, stated that the current definition is appropriate, and that PHMSA should review its current MOU with the Environmental Protection Agency (EPA) before making any changes to avoid duplicative regulation of these facilities. DLA, a governmental/municipal entity, echoed the comments of API–AOPL.

Conversely, NAPSR stated that if PHMSA is referring to the large number of small tanks that are technically under PHMSA's authority, but currently not regulated, then this exception should be removed.

Response

The Pipeline Safety Laws provide PHMSA with broad authority to regulate ''the storage of hazardous liquid incidental to the movement of hazardous liquid by pipeline'' (49 U.S.C. 60101(a)(22)(A)). The term ''breakout tank'' is defined in § 195.2 to designate which aboveground tanks are regulated as breakout under part 195. See Exxon Corporation v. U.S. Department of Transportation, 978 F.Supp. 946, 949–54 (E.D. Wash. 1997).

As some of the commenters noted, PHMSA has an MOU with EPA on the treatment of breakout tanks and bulk storage tanks under the requirements of the Oil Pollution Act of 1990. Such agreements can ensure the effective regulation of facilities that are subject to regulation by more than one federal agency. As in the case of offshore pipeline facilities, those agreements can also serve as a guideline on whether a tank is transportation related or non-transportation related.

Accordingly, PHMSA will review its agreements with EPA to determine whether any modifications are necessary, but is not proposing to change the definition of a ''breakout tank'' in part 195 at this time.

Other Exceptions or Limitations in Part 195

In the ANPRM, PHMSA asked for comment on whether the agency should repeal or modify any of the other exceptions in part 195. API–AOPL, supported by several other trade associations, including LMOGA, TxOGA, OIPA, and IPAA, commented that the exception in § 195.1(b)(8) for transportation of hazardous liquid or carbon dioxide through onshore production (including flow lines), refining, or manufacturing facilities or storage or in-plant pipeline systems associated with such facilities should not be changed. API–AOPL commented that these facilities are not within the scope of the Pipeline Safety Laws, because they are not typically operated by midstream oil and gas pipeline companies operating in the pipeline transportation system. These facilities are already covered under a 1972 MOU with EPA and do not require further duplicative regulation.

Comments

API–AOPL commented that the exception in § 195.1(b)(9) for piping located on the grounds of a materials transportation terminal used exclusively to transfer products between non-pipeline modes of transportation should not be changed. This piping is typically isolated from pipeline pressure by devices that control pressure in the pipeline under § 195.406(b). TransCanada Keystone, an industry commenter, supported API–AOPL's comments.

The citizens' groups NRDC and PST indicated that PHMSA should establish additional standards for diluted bitumen. Both groups suggested PHMSA establish additional regulations for that commodity due to the high temperatures and pressures at which the lines that carry it operate.

Both regulatory associations, NAPSR and MAWUC, commented on other exemptions or limitations of the pipeline safety regulations. NAPSR indicated that the exemptions for pipelines under 1-mile long that serve refining, manufacturing, or terminal facilities should be eliminated for ethanol pipelines. NAPSR also requested that PHMSA verify that intrastate lines carrying other hazardous liquids, such as sulfuric acid, are regulated by the states. MAWUC indicated that there should be no regulatory exceptions in HCA segments, because these areas must be treated with the highest degree of both prevention and emergency remediation measures.

Among government and municipality commenters, NSB stated that § 195.1 should be amended to include regulation of all onshore pipelines and offshore pipelines in areas of the North Slope. NSB suggests regulation should occur where the consequences of a hazardous liquid pipeline failure could adversely impact: (1) An endangered, threatened or depleted species; (2) subsistence resources and subsistence use areas; (3) a drinking water supply; (4) cultural, archeological, and historical resources; (5) navigable waterways (including waterways navigated by rural residents for the purposes of recreation, commerce, and subsistence use); (6) recreational use areas; or (7) the functioning of other regulated facilities. Regulation of all high pressure, large diameter (6-inch and greater) onshore pipelines and all offshore pipelines should start at the wellhead.

One citizen commented that the river and coastline routes in the Arctic and sub-Arctic are particularly of concern because of the rapid change in permafrost, as well as high rate of coastal erosion, which greatly increase the environmental and human impacts of hazardous liquid spills.

Response

Section 195.1(b)(8) states that part 195 does not apply to the transportation of hazardous liquid or carbon dioxide through onshore production (including flow lines), refining, or manufacturing facilities or storage or in-plant piping systems associated with such facilities. That exception is based on section 60101(a)(22) of the Pipeline Safety Laws, which exempts the movement of hazardous liquid through onshore production, refining, or manufacturing facilities; or storage or in-plant piping systems associated with onshore production, refining, or manufacturing facilities. Accordingly, PHMSA agrees with the commenters that the exception in § 195.1(b)(8) should not be changed.

With respect to the terminal exemption in § 195.1(b)(9)(ii), it should first be noted that the term ''Pipeline or pipeline system'' is defined in § 195.2 as ''all parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves, and other appurtenances connected to line pipe, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.'' The term ''Pipeline facility'' is defined in § 195.2 as ''new and existing pipe, rights-of-way and any equipment, facility, or building used in the transportation of hazardous liquids or carbon dioxide.'' Under 49 U.S.C. 60101(a)(22), ''transporting hazardous liquid'' includes ''the storage of hazardous liquid incidental to the movement of hazardous liquid by pipeline.''

Section 195.1(b)(9) states that part 195 does not apply to the transportation of hazardous liquid or carbon dioxide by vessel, aircraft, tank truck, tank car, or other non-pipeline mode of transportation or through facilities located on the grounds of a materials transportation terminal if the facilities are used exclusively to transfer hazardous liquid or carbon dioxide between non-pipeline modes of transportation or between a non-pipeline mode and a pipeline. These facilities do not include any device and associated piping that are necessary to control pressure in the pipeline under § 195.406(b).

One of PHMSA's predecessors, the Materials Transportation Bureau (MTB), adopted the original version of that exception in a July 1981 final rule July 27, 1981, (46 FR 38357). In excepting the ''[t]ransportation of a hazardous liquid by vessel, aircraft, tank truck, tank car, or other vehicle or terminal facilities used exclusively to transfer hazardous liquids between such modes of transportation,'' MTB stated that: [Its] authority to establish minimum Federal hazardous liquid pipeline safety standards under the [Hazardous Liquid Pipeline Safety Act (HLPSA) of 1979] extends to ''the movement of hazardous liquids by pipeline, or their storage incidental to such movement.'' The Senate report that accompanied the HLPSA states that, ''It is not intended that authority over storage facilities extend to storage in marine vessels or storage other than those which are incidental to pipeline transportation.'' (Sen. Rpt. 96–182, 1st Sess., 96th Cong. (1979), p. 18.) Earlier laws had vested DOT with extensive authority to prescribe safety standards governing the movement of hazardous liquids in seagoing vessels, barges, rail cars, trucks or aircraft and storage incidental to those forms of transportation. From the words of the new HLPSA and the related Senate report language, it is clear that Congress did not want to duplicate or overlap any of those earlier laws. Thus, HLPSA regulatory authority over storage does not extend to any form of transportation other than pipeline or to any storage or terminal facilities that are used exclusively for transfer of hazardous liquids in or between any of the other forms of transportation unless that storage or terminal facility is also ''incidental'' to a pipeline which is subject to the HLPSA. These storage and terminal facilities are expressly excluded from the coverage of part 195 July 27, 1981, (46 FR 38358). RSPA modified that exception in the final rule June 28, 1994, (59 FR 33388).

RSPA, however, continued to maintain the exclusion for the transportation of hazardous liquids or carbon dioxide by non-pipeline modes, and added a more detailed exclusion for transfer piping located on the grounds of a materials transportation terminal.

The regulatory history demonstrates that the exception in § 195.1(b)(9) is designed to exclude piping used in transfers to non-pipeline modes of transportation and the facilities and piping at terminals that are used exclusively for such transfers. The provision is drafted to ensure that any piping that is not used exclusively to transfer product between non-pipeline modes or transportation between a non-pipeline mode and a pipeline and facilities are subject to regulation by PHMSA. None of the commenters argued in favor of changing the exception, and there is no information to suggest that such action is necessary at this time. Accordingly, PHMSA is not proposing to modify or repeal § 195.1(b)(9).

With regard to the remaining comments, section 16 of the Pipeline Safety Act of 2011 requires the Secretary to perform a comprehensive review of whether the requirements in part 195 are sufficient to ensure the safety of pipelines that transport diluted bitumen (dilbit) and to provide Congress with a report on the results of that review. That review, titled ''Effects of Diluted Bitumen on Crude Oil Transmission Pipelines,'' was performed by the National Academy of Sciences and was published in 2013. The review found there were no causes of pipeline failure unique to the transportation of diluted bitumen, or evidence of chemical or physical properties of diluted bitumen shipments that are outside the range of other crude oil shipments, or any other aspect of diluted bitumen's transportation by pipeline that would make it more likely than other crude oils to cause releases.[3] However, the safety proposals in this rulemaking address all hazardous liquid pipelines, which include pipelines that transport diluted bitumen.

Multiproduct petroleum pipelines transporting ethanol blends of up to 95% are currently regulated by PHMSA under part 195 and no major ethanol spills have occurred on these pipelines. PHMSA is performing additional research into the technical issues associated with the transportation of ethanol by pipeline and will use that information to determine whether such transportation should be subject to any additional safety requirements in the future. This NPRM proposes to conform part 195 with 49 U.S.C. 60101(a)(4) making the transportation by pipeline of any biofuel that is flammable, toxic, corrosive, or would be harmful to the environment if released in significant quantities, subject to part 195.

The requirements for HCA's are addressed in another portion of this document. As noted above, PHMSA is proposing to extend the federal reporting requirements to all hazardous liquid gathering lines (whether onshore, offshore, regulated, or unregulated).

In conclusion, PHMSA will not be proposing to change or eliminate any other regulatory exceptions at this time. The exception for carbon dioxide pipelines is limited in scope and only applies to production facilities. Although breakout tanks are defined in a way that limits the application of part 195, these certain storage tanks may also be subject to regulation by EPA. PHMSA continues to study the scope of the gathering line exemptions, but is not proposing to modify these or any other exemption. At present, nothing indicates that any of the other exceptions should be modified as part of this rulemaking proceeding, or that the issuance of regulations for underground storage facilities is necessary.

Additional Safety Standards for Underground Hazardous Liquid Storage Facilities

The definition of a pipeline facility in part 195 includes ''any equipment, facility, or building used in the transportation of hazardous liquids . . .'' and, as already noted above, includes storage terminals. While surface piping in storage fields located at midstream terminal facilities falls within this definition, part 195 does not contain comprehensive safety standards for the ''downhole'' underground hazardous liquid storage caverns. In addition, surface piping at storage fields located either at the production facility where a pipeline originates or a destination/consumption facility where a pipeline terminates would generally not be considered part of the transportation and, therefore, not be regulated by PHMSA in the manner that such piping located on the grounds of the midstream terminal would. RSPA provided an explanation in a July 1997 advisory bulletin June 2, 1997, (62 FR 37118) which the agency issued in response to a NTSB recommendation on the regulation of underground storage caverns (P–93–9). RSPA noted in that advisory bulletin that a recent report indicated that state regulations applied in some form to significant percentages of these facilities, and that API had developed a set of comprehensive guidelines for the underground storage of liquid hydrocarbons. As result of these state regulations, the API guidelines, and ''the varying and diverse geology and hydrology of the many sites'' RSPA stated that agency had ''decided that generally applicable federal standards may not be appropriate for underground storage facilities.'' June 2, 1997, (62 FR 37118) RSPA further stated it would be ''encouraging state action and voluntary industry action as a way to assure underground storage safety instead of proposing additional federal regulations.'' *Id.* PHMSA understands that Court decisions preempting state from regulating interstate facilities appears to be a concern for state regulators.

Comments

PHMSA requested comment on the promulgation of new or additional safety standards for underground hazardous liquid storage. The industry commenter, TransCanada Keystone, supported the comments of API–AOPL, as did the trade associations LMOGA and TxOGA. API–AOPL stated that the current exclusion of the underground cavern is appropriate as they are already regulated by the states. API–AOPL indicated that the states are better suited to regulate these facilities because of their knowledge of these facilities and locations.

One government/municipality, DLA, commented that there was no need for new regulations for underground hazardous liquid storage facilities. DLA maintains that these facilities are currently regulated for purposes of the Clean Air Act under both 40 CFR parts 112 and 280 by the EPA.

Response

None of the commenters supported the issuance of additional regulations for underground hazardous liquid storage caverns, and there is no information suggesting that such action is necessary at this time. Therefore, PHMSA is not proposing to issue any new regulations for underground storage of hazardous liquids in this proceeding.

Order in Which Regulatory Changes Should Be Made in to Best Protect the Public, Property, or the Environment

Comments

PHMSA received comments from industry, trade associations, one government/municipality, and one regulatory association responding to the question on the order of the actions PHMSA should take to best protect the public, property, or the environment. API–AOPL, supported by TransCanada Keystone and the trade associations, OIPA, TxOGA, and LMOGA, indicated that PHMSA's actions should be risk-based. Similarly, NAPSR had no recommendation on the order, but suggested that it be based on risk.

The government/municipality NSB requested that PHMSA place a high priority on the repeal of regulatory exceptions for gathering of hazardous liquids in rural areas, offshore pipelines in state waters, and producer-operated lines on the OCS. NSB stated that unregulated rural pipelines are located in Unusually Sensitive Areas (USAs) of the NSB. These pipelines cross sensitive arctic tundra vegetation and impact areas used by endangered species. As North Slope development continues to expand to the west, east, and south,

[3] *http://phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Pipeline/Dilbit_1_Transmittal_to_Congress.pdf.*

impacts to NSB communities and USAs will increase.

Response

PHMSA is proposing to repeal the exception for gravity lines and to apply the reporting requirements in part 195 to all gathering lines.

B. Definition of High Consequence Area

In the ANPRM, PHMSA asked for public comment on whether to modify the requirements in part 195 for HCAs. Specifically, PHMSA asked whether:

• The criteria for identifying HCAs should be changed to incorporate additional pipeline mileage or better reflect risk;

• All navigable waterways should be included within the definition of an HCA;

• The process for making HCA determinations on pipeline ROWs can be improved;

• The public and state and local governments should be more involved in making HCA determinations;

• Additional safety requirements should be developed for areas outside of HCAs; and

• Major road and railway crossings should be included within the definition of an HCA.

As discussed in detail later in the Background and NPRM Proposals section, PHMSA is proposing to adopt additional safety standards for pipelines that are located outside of areas that could affect an HCA. These measures will increase the safety of all of the nation's pipelines without necessitating any change to the HCA definition; therefore, PHMSA is not taking any further action on that proposal at this time.

Expanding the Definition of HCA To Include Additional Pipeline Mileage

In the ANPRM, PHMSA asked whether the current criteria for identifying HCAs should be modified to incorporate additional pipeline mileage.

Comments

TransCanada Keystone recommended that PHMSA further define the meaning of an HCA, and that the agency provide greater clarity with respect to the HCA classification, including the magnitude of impacts that differentiate HCAs from other areas.

API–AOPL, supported by the trade associations, TxOGA and LMOGA, and an industry commenter, TransCanada Keystone, stated that the current criteria should not be changed. API–AOPL stated that PHMSA should serve a clearinghouse function by displaying HCA information on the NPMS, with updates every 10 years based on census information. API–AOPL further noted that ''other populated areas'' includes Census-delineated areas, like Metropolitan Statistical Areas (MSA) and Consolidated Metropolitan Statistical Areas, which are not densely populated, and that the current HCA criteria are thus conservative. API–AOPL also stated that the current ability of operators to demonstrate why segments of pipeline could not affect an HCA should be retained.

The trade associations, OIPA and TPA, suggested that more data is needed to make a decision on HCA definition expansion, and that any changes would likely impact small operators.

Among citizens' groups, PST favored expanding the IM requirements to all hazardous liquid lines, with initial inspections required within 5 years of identification. PST stated that using census data to designate high population and other population areas is arbitrary and not necessarily a predictor of risk. Noting that the public could not fully comment because HCA boundaries are not publicly available (for security reasons); PST stated that the definition of HCA should be expanded to include national parks, monuments, recreation areas, and national forests. PST also pointed to the recent trend in extreme accidents in HCAs.

Two other citizens' groups, AKW and NRDC, commented. AKW requested that the criteria be changed. NRDC indicated that PHMSA should have a broader definition of HCAs, particularly with respect to ecological resources and drinking water criterion.

NAPSR commented that the current criteria are generally adequate, but that other threats and risks could be considered, including petroleum product supply loss, leaks that could affect private wells, and impacts to major infrastructure.

NSB favored an expansion of HCAs to include pipelines located in subsistence areas, cultural resources, archeological, historical, and recreational areas of significance and offshore.

Response

Congress recently directed the Secretary to prepare a report on whether the IM requirements should be extended to pipelines outside of areas that could affect HCAs. The Secretary is prohibited from issuing any final regulations that would expand those requirements during a subsequent Congressional review period, unless those regulations are necessary to address a condition posing a risk to public safety, property, or the environment, or an imminent hazard. PHMSA is preparing the Secretary's report to Congress on the need to expand the IM requirements and is not proposing to change the definition of an HCA to incorporate additional pipeline mileage at this time.

PHMSA is, however, proposing to adopt additional safety standards for pipelines that are not covered under the IM program requirements. The proposals are detailed later in this NPRM under the Background and NPRM proposals section.

PHMSA is aware of its obligation to consider other locations near pipeline ROWs in defining USAs, including ''critical wetlands, riverine or estuarine systems, national parks, wilderness areas, wildlife preservation areas or refuges, wild and scenic rivers, or critical habitat areas for threatened and endangered species.'' However, PHMSA is not proposing to make any of these areas USAs in light of the new requirements that are being proposed for non-IM pipelines. PHMSA will be considering whether to include these locations in the HCA definition in performing the evaluation required under section 5 of the Pipeline Safety Act of 2011 and will comply with the applicable provisions of that legislation before taking any final regulatory action to adopt the proposed requirements for non-IM pipelines.

Modifying the Definition of HCA to Better Reflect Risk

PHMSA asked whether the criteria for identifying HCAs should be changed to better reflect risk.

Comments

TransCanada Keystone's comment focused specifically on the classification of groundwater USAs in § 195.6, stating that groundwater HCA buffers should not be expanded, and that the existing criteria, which identify community water intakes where contamination has the potential to cause greater impacts compared to other areas, are sufficient.

API–AOPL stated that there are various risk factors applicable to HCA classifications and that the current definition should not be changed. API–AOPL recommended that buffer zones be used as an acceptable alternative to the more detailed ''could affect'' analysis for new, expanded, or modified HCAs. API–AOPL also suggested that operators should retain the ability, with technical justification, to determine whether a pipeline can actually impact an HCA. TransCanada Keystone, LMOGA, and TxOGA endorsed API–AOPL's comments. TPA, the other trade association commenter, mentioned that more data was needed to make a final decision on this matter.

A number of citizens' groups commented on this issue. NRDC, AKW, and TWS indicated the HCA definition needs to be broadened to reflect risk and to include entire pipelines in some cases. NRDC stated that the threshold for a populated area should be lowered, and that the definition of populated areas and USA should be improved. NRDC commented that the current HCA definition provides limited protection to threatened or endangered species. NRDC also recommended strengthening the USA definition to protect more migratory bird areas and national landmarks, including national parks, wild and scenic rivers, estuaries, wilderness areas, wildlife refuges, and drinking water sources, including private wells and open source aquifers. TWS and AKW proposed to revise the HCA criteria to include all transportation infrastructure, public lands, waterways, wetlands, and cultural, historic, archeological, and recreation sites, including subsistence areas.

NAPSR stated that the current HCA definition should not be changed, but that PHMSA should consider incorporating others threats and risks, including supply interruptions and small leaks that could affect private wells.

NSB favored changing the existing HCA definition. NSB stated that USAs should include subsistence, cultural, archeological, historical, and recreational areas of significance within the NSB and offshore waters of the Beaufort and Chukchi Seas. NSB suggested a formal process for nominating areas that should be afforded HCA status, and that the NPMS data should be updated.

Both MAWUC and DLA indicated the definition could be modified to better reflect risk. MAWUC suggested a tiered, prioritized system with enforceable criteria that are appropriate for the risk to water supplies. DLA stated that higher risk locations should be protected instead of simply creating more HCAs.

Response

PHMSA is not proposing to make any changes to the criteria for identifying HCAs at this time. The existing Census-based approach for determining high population and other populated areas ensures uniformity and provides an adequate margin of safety by including some less densely populated areas. None of the commenters offered a more effective alternative.

PHMSA recognizes that other areas of ecological, cultural, or national significance could be designated as USAs. However, PHMSA is not proposing to add any of these areas in light of the new safety standards that are being proposed for hazardous liquid pipelines that are not subject to the IM program requirements.

PHMSA does not support any of the suggested alternative approaches for identifying HCAs. The widespread use of the buffer method is not justified based on the available information, and the use of a more lenient standard in making HCA determinations would not provide adequate protection for these sensitive areas. PHMSA will revisit these conclusions in preparing the Secretary's report to Congress on expanding the IM program for hazardous liquid pipelines.

Commercial Limitation on Navigable Waterways

The ANPRM posed the question of expansion of the definition of HCAs beyond commercially navigable waterways.

Comments

Several trade associations, API–AOPL, OIPA, and IPAA, and one industry representative, TransCanada Keystone, opposed expanding the HCA definition beyond commercially navigable waterways. These commenters stated that the vast majority of surface waters are already covered under the present criteria. TPA stated that adopting a navigable waters standard would make every creek an HCA, resulting in a significant increase in the burden associated with implementing IM requirements.

Two citizens' groups commented on the phrase ''commercially navigable.'' PST also recommended defining HCA to include all ''waters of the United States,'' provided PHMSA did not adopt its suggestion to apply IM requirements to all regulated pipelines. NRDC proposed to amend the term ''commercially navigable waterways'' to include other bodies of water that are not necessarily navigable, such as lakes, streams, and wetlands.

Two government/municipalities commented on the commercial limitation on navigable waterways. DLA, a government/municipality, echoed the comments of the trade associations and TransCanada Keystone previously mentioned. NSB requested PHMSA change commercially navigable to ''navigable waters'' or ''waters of the U.S.'' to encompass more environmentally-sensitive areas.

Response

Section 195.450 states that an HCA includes any ''waterway where a substantial likelihood of commercial navigation exists.'' RSPA first proposed to include commercially navigable waterways as HCAs in the April 2000 NPRM that contained the original IM requirements for hazardous liquid pipelines April 24, 2000, (65 FR 21695). RSPA stated that it ''[wa]s including commercially navigable waterways in the proposed [HCA] definition[,] [b]ecause these waterways are critical to interstate and foreign commerce and supply vital resources to many American communities, are a major means of commercial transportation, and are a part of a national defense system, a pipeline release in these areas could have significant impacts.'' April 24, 2000, (65 FR 21700).

RSPA adopted the HCA definition as proposed in the NPRM in the final rule December 1, 2000, (65 FR 75378). In the preamble to that final rule, RSPA stated that it had received the following comments on its proposal to include commercially navigable waterways in the HCA definition:

API and liquid operators questioned the inclusion of commercially navigable waterways into the HCA's definition. API pointed out that Congress required OPS to identify hazardous liquid pipelines that cross waters where a substantial likelihood of commercial navigation exists and once identified, issue standards, if necessary, requiring periodic inspection of the pipelines in these areas. API said that OPS had not determined the necessity for including these waterways in areas that trigger additional integrity protections. BP Amoco said the rule should be limited to protection of public safety, rather than commercial interests. Enbridge and Lakehead also questioned why waterways that are not otherwise environmentally sensitive should be included for protection.

EPA Region III said that we should also consider recreational and waterways other than those for commercial use. Environmental Defense, Batten, City of Austin and other[s] commented that we should consider all navigable waterways as HCA's, because of the environmental consequences a hazardous liquid release could have on such waters. December 1, 2000, (65 FR 75390).

RSPA provided the following response to those comments:

''Our inclusion of commercially navigable waterways for public safety and secondary reasons is not based on the ecological sensitivity of these waterways. Parts of waterways sensitive for ecological purposes are covered in the proposed USA definition, to the extent that they contain occurrences of a threatened and endangered species, critically imperiled or imperiled species, depleted marine mammal, depleted multi-species area, Western Hemispheric Shorebird Reserve Network or Ramsar site. We are including commercially navigable waterways as HCAs because these waterways are a major means of commercial transportation, are critical to interstate and foreign commerce, supply vital resources to many American communities, and are part of a national defense system. A pipeline release could have significant consequences on such vital areas by interrupting supply operations due to potentially long response and recovery operations that occur with hazardous liquid spills. December 1, 2000, (65 FR 75391–2).

For these reasons, RSPA defined HCAs in § 195.450 to include commercially navigable waterways.

Thus, the Pipeline Safety Laws do not necessarily limit the definition of an HCA to commercially navigable waterways. RSPA relied on several statutes in promulgating the IM requirements for hazardous liquid pipelines, including the mandates that required the Secretary to establish criteria for identifying pipelines in high density population and environmentally sensitive areas (49 U.S.C. 60109(a)(1)) and to promulgate standards for ensuring the periodic inspection of these lines (49 U.S.C. 60102(f)(2)). Nothing in these provisions or the Pipeline Safety Act of 2011 prohibits PHSMA from using its general rulemaking authority to apply the hazardous liquid pipeline IM regulations to waterways that are not used for commercial navigation. Other kinds of waterways are also referenced in the statutory criteria that must be considered in defining USAs.

PHMSA will be considering the expansion of current HCA or the extension of critical IM requirements to non-HCAs-when completing the Secretary's report to Congress on the need to expand the IM requirement under section 5 of the Pipeline Safety Act of 2011. In the meantime, PHMSA is not proposing to include any additional waterways in the HCA definition.

PHMSA is, however, proposing to adopt other regulations that will increase the safety of our nation's waterways. One such proposal is to require leak detection systems for pipelines in all locations, that operators perform periodic assessments of pipelines not already covered under the IM program requirements, and that new pipeline repair criteria be applied to anomalous conditions discovered in all areas. Another proposal is to require operators to inspect their pipelines in areas affected by extreme weather, natural disasters, and other similar events (*e.g.,* flooding, hurricanes, tornados, earthquakes, landslides, etc.). Following a disaster event, operators will be required to determine whether any conditions exist that could adversely affect the safe operation of a pipeline and to take appropriate remedial actions, such as reductions in operating pressures and repairs of any damaged facilities or equipment.

In regard to seismic events and earthquakes, in determining whether a pipeline has potentially been affected and needs inspection, operators should consider relevant factors such as magnitude of the earthquake, distance from the epicenter, and pipeline characteristics and history. PHMSA recognizes that after considering these factors, operators may determine that smaller seismic events do not have the potential to affect their pipelines. Based on available studies, however, earthquakes over 6.0 in magnitude can potentially damage pipelines and operators would be required to inspect these pipelines.

Operator Process and Public Participation in Making HCA Determinations

PHMSA requested comment on whether the operator's process for making HCA determinations should be modified, including by having greater involvement by the public and state and local governments.

Comments

PHMSA received comments from industry, trade associations, and one regulatory association. API–AOPL supported the existing process for identifying HCAs and suggested that any input from local communities should be through the regulating agency, rather than pipeline operators. OPIA and IPAA noted that a consistent and reliable approach is needed to prevent variations that would result in unnecessary confusion.

The trade associations, TxOGA, LMOGA, API–AOPL, supported by TransCanada Keystone, indicated that operators perform geographic overlay of their pipeline systems with PHMSA-determined HCAs. Operators also utilize the ''could affect'' analysis, which typically considers technical assessments using dispersion models. Through the process of HCA evaluation, operators are sometimes able to determine, with technical justification, that their assets are not capable of impacting an HCA.

NAPSR indicated that PHMSA could consider adding minimum time intervals for operators to review HCA identifications, including a shorter time interval if a pipeline is routed through high population areas. NAPSR also stated that there are areas where private wells have been extremely affected by small leaks that go undetected for years, that this is especially true in areas of sandy soil where leaks do not necessarily bubble up to the surface, and that there should be some consideration to address these ''seepers'' that have very large total leak volume over time.

On the matter of greater public participation, TransCanada Keystone suggested that PHMSA collect data from the states and provide updated HCA information for operator use. The trade associations, LMOGA, TxOGA and API–AOPL, supported by TransCanada Keystone, recommended that additional local involvement be routed through the regulating agency, such as PHMSA. TPA, in contrast, stated that there should be no requirement for public involvement. OIPA and IPAA held that a consistent and reliable approach is needed for the issue of public involvement.

Among the citizens' groups, NRDC supported additional public involvement. Several commenters, including NRDC, PST, and TWS, recommended that the NPMS be revised to display all HCAs so that the public can be better informed.

One regulatory association, NAPSR, suggested that the public be allowed to comment. NAPSR recognized that PHMSA has a process in place for HCA selection that can be enhanced if the public is allowed to provide input. NAPSR stated that the general public and local communities often recognize changes in areas near pipelines before operators.

Government and municipal commenters supported local involvement in the HCA determination process. MAWUC commented that it is important that local communities and water suppliers play a role in preventing and minimizing pipeline failures, including HCA identification. DLA also supported additional public involvement. NSB recommended that state and local governments, as well as local tribes, villages, and the Alaskan Eskimo Whaling Commission, have a role in making HCA determinations.

Response

Congress included new requirements for promoting public education and awareness in section 6 of the Pipeline Safety Act of 2011. Specifically, that provision requires PHMSA (1) to maintain, and update on a biennial basis, a map of designated HCAs in the NPMS; (2) to establish a program that promotes greater awareness of the existence of the NPMS to state and local emergency responders and other interested parties, to include the issuance of guidance on using the NPMS to locate pipelines in communities and local jurisdictions; and (3) to issue additional guidance to owners and operators of pipeline facilities on the importance of providing system-specific information to emergency response agencies. PHMSA believes that such actions will address many of the concerns raised by the commenters.

Additional Safety Requirements for Non-HCA Areas

PHMSA inquired as to whether additional safety measures should be developed for areas outside of HCAs.

Comments

PHMSA received comments from three trade associations and one regulatory association. TransCanada Keystone, TxOGA, API–AOPL, and LMOGA indicated that no new requirements are necessary for areas outside of HCAs. The regulatory association, NAPSR, remarked that operators should be precluded from turning off in-line inspection sensors outside of an HCA when performing an integrity assessment under the IM regulations.

Response

PHMSA agrees with the NAPSR comment and has likewise found that some operators do turn off inspection tools outside of HCAs. Therefore, PHMSA is proposing to require that operators perform periodic assessments of pipelines that are not already covered under the IM program requirements in § 195.452. Promulgation of such a requirement will ensure that pipeline operators obtain the information necessary for the prompt detection and remediation of corrosion and other deformation anomalies (*e.g.,* dents, gouges, and grooves) in all locations, not just in areas that could affect HCAs.

Inclusion of Major Road and Railway Crossings as HCAs

PHMSA requested comment on the need to include major road and railway crossings as HCAs.

Comments

Industry, three trade associations, three citizens' groups, one regulatory association, one government/municipality, and one citizen commented on this question.

TransCanada Keystone, supported by the trade associations, API–AOPL, TPA, TxOGA, and LMOGA, opposed including major roads and railway crossings as HCAs. The commenters offered several reasons to support that position (*e.g.,* such a change would draw resources from other more high risk areas, non-HCA areas are already assessed and remediated, and there is no data to support such an action).

Among the citizens' groups, PST stated that rail and major road crossings should be included. TWS and AKW stated that all transportation infrastructure, public lands, wetlands under the Clean Water Act (CWA), cultural, historical, archeological and recreation areas used for subsistence be included in HCAs.

NAPSR also suggested that rail and major road crossings should be included. NAPSR urged PHMSA to consider the effect of a release on electric transmission facilities, gas pipelines, and railroads if major road and rail crossings were not to be included in HCAs. NAPSR would consider the effect of a release on electric transmission facilities, gas pipelines, railroads, etc., and would treat major road and rail crossings as HCAs for highly volatile liquids (HVLs) pipelines.

The only government/municipality to comment on this question was DLA. DLA indicated that these structures should be included in HCAs.

Citizen Coyle commented that major roadways should be HCAs because these areas could be affected by pipelines carrying HVLs that would produce poisonous clouds if released.

Response

PHMSA is not proposing to designate major road and railway crossings as HCAs, but will consider whether the pipeline IM requirements should be applied to these areas when completing the study that Congress mandated under section 5 of the Pipeline Safety Act of 2011. PHMSA notes that the pipelines at such crossings would be afforded additional protections under the other proposals made in this proceeding, including the requirements for the performance of periodic internal inspections and the use of leak detection systems.

C. Leak Detection Equipment and Emergency Flow Restricting Devices

In the ANPRM, PHMSA asked for comment on whether to modify the current requirements part 195 for leak detection equipment and emergency flow restricting devices (EFRDs). Specifically, PHMSA asked whether

- The use of leak detection equipment should be required for hazardous liquid pipelines;
- The pipeline industry has developed any practices, standards, or leak detection technologies that should be incorporated by reference;
- Any industry practices or standards adequately address the relevant safety considerations;
- State regulations for leak detection should be adopted by regulation;
- Any new leak detection requirements should vary based on the sensitivity of the affected areas;
- The pipeline industry has developed standards or practices for the performance and location of EFRDs;
- The location of EFRDs should be specified by regulation; and
- Additional research and development is needed to demonstrate the suitability of any new leak detection technologies.

As discussed below, PHMSA is considering requiring that all hazardous liquid pipelines have a system for detecting leaks and expand the use of EFRDs.

Expansion of Leak Detection Requirements

In the ANPRM, PHMSA asked for comment on whether the agency should expand the leak detection requirements.

Comments

Industry and trade associations generally supported expansion of the existing requirement in § 195.452(i)(3) to most pipelines, but opposed including more-specific requirements in the regulations. API–AOPL, TxOGA, TransCanada Keystone, and LMOGA supported extending leak detection requirements to all PHMSA-regulated pipelines, except for rural gathering lines.

Citizens' groups supported enhanced leak detection requirements. TWS and PST opposed additional reliance on the current requirements in § 195.452(i)(3), stating that this regulation includes no acceptance criteria and is virtually unenforceable. TWS further supported expanding leak detection requirements to all pipelines under PHMSA jurisdiction. NRDC indicated that leak detection requirements should be expanded to include a requirement that worst-case-discharge-pumping times be based on historical shutdown times, rather than expected times. NRDC also said that operators should immediately contact first responders at the first sign of an issue. One citizen, Stec, suggested requiring use of ''smart coating'' with embedded conductors that would break to indicate coating damage and which could then trigger automatic response actions.

The regulatory associations, DLA and MAWUC, supported expanded leak detection requirements. MAWUC suggested PHMSA require the use of leak detection equipment in all HCAs. DLA indicated that any new requirements should be delayed until better technology is available.

The government/municipality, NSB, recommended leak detection requirements be expanded to all pipelines under PHMSA regulation. NSB encouraged adoption of more stringent leak detection requirements for sensitive offshore areas of the Beaufort and Chukchi seas.

Response

As discussed earlier in this NPRM under the Background and Proposals section, PHMSA will propose to expand the leak detection requirements for HCA and non-HCA areas.

Consideration of New Industry Standards or Practices in Leak Detection

PHMSA asked for public comment on whether any new industry standards or practices should be considered for adoption in part 195.

Comments

API–AOPL, TxOGA, LMOGA, and TransCanada Keystone all indicated that the API–AOPL standard RP1165 (SCADA), RP 1167 (Pipeline Alarm Management), and RP1168 (Control Room Management) are good standards to utilize for leak detection systems. API–AOPL also pointed out that many new technologies are being developed and existing methodologies are continuously being improved for better leak detection capability; however, many of these new technologies have not been proven in service on cross-country pipelines.

One citizens' group, NRDC, commented that new leak detection standards should address the additional demands posed by hazardous liquids. In particular, NRDC mentioned some hazardous liquids, such as diluted bitumen, have multiphase properties that can cause false alarms.

The regulatory associations, NAPSR and DLA, both commented on new industry standards and practices in leak detection. NAPSR mentioned the new technology forward-looking infrared radar (FLIR) and encouraged PHMSA to consider using such new technologies. NAPSR reported that FLIR can detect changes in temperature near a pipeline from a winter leak, even under snow, and that it can be used from aerial patrols.

DLA indicated that any leak detection standards should be third-party validated and listed by the National Work Group on Leak Detection Evaluations (NWGLDE) and that leak detection in general for large volume pipelines is not very effective at this time.

Response

The commenters only offered three specific industry standards or practices for consideration, and two of those standards, API RP1165 (SCADA) and RP1168 (Control Room Management), are already incorporated into part 195 (*see* 49 CFR 195.3). PHMSA has concerns about the adequacy and enforceability of the third standard, API RP 1167 (Pipeline Alarm Management), and does not believe that it should be incorporated by reference at this time.

As previously discussed, PHMSA is proposing to require that operators have a means for detecting leaks on all portions of a hazardous liquid pipeline system. Consideration of FLIR and any other emerging technologies would be required in evaluating what kinds of leak detection systems are appropriate for a particular pipeline. PHMSA will also be considering whether the use of specific leak detection technologies should be required in preparing the Secretary's report to Congress on that issue.

PHMSA does not agree that third-party validation is a prerequisite to issuing new leak detection requirements for hazardous liquid pipelines. That limitation is not included in the Pipeline Safety Laws, and PHMSA does not believe that such action is necessary as a matter of administrative discretion.

Adequacy of Existing Industry Standards or Practices for Leak Detection

PHMSA asked for public comment on whether any existing industry standards or practices for leak detection are adequate for adoption into part 195.

Comments

TransCanada Keystone, TxOGA, LMOGA and API–AOPL submitted comments indicating that the current leak detection evaluations performed as a requirement of the IM program encompass many important factors for proper leak detection. PHMSA should allow for the implementation of recent regulatory changes, including the new Control Room Management (CRM) rule, before making any changes. NAPSR commented that all pipeline operators should, at a minimum, perform a tank balance periodically to detect leakage.

NSB recommended that PHMSA adopt improved leak detection system standards and implement more stringent leak detection requirements for the sensitive offshore areas of the Beaufort and Chukchi seas. NSB stated that PHMSA should require: (1) Redundant leak detection systems for offshore pipelines; (2) All offshore pipeline leak detection systems to have the continuous capability to detect a daily discharge equal to not more than 0.5% of daily throughput within 15 minutes, and detect a pinhole leak within less than 24 hours; (3) All onshore pipeline leak detection systems to have the continuous capability to detect a daily discharge equal to not more than 1% of daily throughput within 15 minutes, and detect a pinhole leak within less than 24 hours; and (4) An initial performance test to verify leak detection accuracy upon installation and at regular intervals thereafter.

Response

PHMSA agrees that the factors listed in § 195.452(i)(3) are an appropriate basis for determining whether hazardous liquid pipelines have an adequate leak detection system and is proposing to use those factors as the basis for the requirements that would apply in all other locations. However, a December 31, 2007, report that PHMSA prepared in response to a mandate in the Pipeline Inspection, Protection, Enforcement, and Safety Act (PIPES Act) of 2006 (Pub. L. 109–468), confirmed that some operators had IM procedures that did not require the performance of a leak detection evaluation, and others had adopted an inadequate process for performing those evaluations. Operators are reminded that any failure to comply with part 195, including the leak detection requirements in § 195.452(i)(3) and the proposed modifications to §§ 195.134 and 195.444, increases both the likelihood and severity of pipeline accidents.

PHMSA agrees that the new CRM requirements will improve the detection and mitigation of leaks on hazardous liquid pipeline systems, but does not agree that the implementation of improved leak detection requirements should be delayed solely on account of the recent issuance of those regulations. PHMSA will be monitoring the use of leak detection systems by operators in complying with those requirements in determining if additional safety standards are needed.

Consideration of State Requirements/ Regulations for Leak Detection

Some states have established leak detection requirements for hazardous liquid pipeline systems. For example, the Alaska Department of Environmental Conservation (ADEC) has promulgated a regulation (18 AAC 75.055) that states:

(a) A crude oil transmission pipeline must be equipped with a leak detection system capable of promptly detecting a leak, including

(1) if technically feasible, the continuous capability to detect a daily discharge equal to not more than one percent of daily throughput;

(2) flow verification through an accounting method, at least once every 24 hours; and

(3) for a remote pipeline not otherwise directly accessible, weekly aerial surveillance, unless precluded by safety or weather conditions.

(b) The owner or operator of a crude oil transmission pipeline shall ensure that the incoming flow of oil can be completely stopped within one hour after detection of a discharge.

(c) If above ground oil storage tanks are present at the crude oil transmission pipeline facility, the owner or operator shall meet the applicable requirements of 18 AAC 75.065, 18 AAC 75.066, and 18 AAC 75.075.

(d) For facility oil piping connected to or associated with the main crude oil transmission pipeline the owner or operator shall meet the requirements of 18 AAC 75.080.

Operators who install online leak detection systems can also receive a reduction in the volume of crude oil that must be used in complying with Alaska's oil spill response planning requirements (18 AAC 75.436(c)(3)).

The State of Washington has also prescribed leak detection requirements for hazardous liquid pipelines (WAC 480–75–300). Those requirements, which are administered by the Washington Utilities and Transportation Commission (WUTC), state:

(1) Pipeline companies must rapidly locate leaks from their pipeline. Pipeline companies must provide leak detection under flow and no flow conditions.

(2) Leak detection systems must be capable of detecting an eight percent of maximum flow leak within fifteen minutes or less.

(3) Pipeline companies must have a leak detection procedure and a procedure for responding to alarms. The pipeline company must maintain leak detection maintenance and alarm records.

Comments

PHMSA received comments from several trade associations and one citizens' group on state requirements for leak detection systems. API–AOPL indicated that pipeline configuration and operational factors vary by geographic location, and that other variability exists, including fluid or product differences, batching, and other operational conditions. Due to these factors, any type of prescriptive approach to standards for leak detection is difficult to achieve and would be better served using a performance standard. CRAC noted that multi-phase lines are more susceptible to internal corrosion, and that state regulations do not require IM or leak detection.

NAPSR and DLA also commented. NAPSR encouraged PHMSA to allow the states to set minimum leak detection criteria for intrastate pipelines. DLA opposed development of criteria based on state requirements and suggested that new requirements be third-party validated and listed by NWGLDE.

Response

PHMSA favors the use of performance-based safety standards and believes that the regulations adopted by ADEC and WUTC show that certain minimum threshold requirements can be established for leak detection systems. PHMSA will be considering these and other similar regulations in an evaluation of leak detection systems.

With regard to NAPSR's comment, section 60104(c) of the Pipeline Safety Laws allows states that have submitted a current certification to adopt additional or more stringent safety standards for intrastate hazardous liquid pipeline facilities, so long as those requirements are compatible with the minimum federal safety standards. PHMSA has prescribed mandatory leak detection requirements for hazardous liquid pipelines that could affect HCAs and is proposing to make those requirements applicable to all pipelines subject to part 195. States that have submitted a current certification can establish additional or more stringent leak detection standards for intrastate hazardous liquid pipeline facilities, subject to the statutory compatibility requirement.

PHMSA does not agree that third-party validation is a prerequisite to issuing new leak detection requirements for hazardous liquid pipelines. That limitation is not included in the Pipeline Safety Laws, and PHMSA does not believe that such action is necessary as a matter of administrative discretion.

Different Leak Detection Requirements for Sensitive Areas

Section 195.452(i)(3) contains a mandatory leak detection requirement for hazardous liquid pipelines that could affect an HCA. That regulation requires operators to consider several factors (*i.e.,* the length and size of the pipeline, type of product carried, proximity to the HCA, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results) in selecting an appropriate leak detection system.

Comments

PHMSA received many comments in response to whether there should be different leak detection requirements for sensitive areas. The trade associations, TxOGA and LMOGA, supported API–AOPL's comments that most leak detection methods cannot target specific areas. API–AOPL further stated that leak detection for sensitive areas can be achieved through comprehensive risk-based evaluation, but that external monitoring is too invasive and is not yet proven or cost effective.

The regulatory associations, government/municipalities, and citizens all supported increased leak detection requirements for sensitive areas. The regulatory association, NAPSR, mentioned the use of FLIR for sensitive areas and stated that special actions beyond patrols should be required for sensitive areas. DLA indicated leak detection standards should be third-party validated. MAWUC and a citizen, Coyle, recommended requiring external leak detectors in HCAs. Coyle would also require external leak detectors for above-ground pipelines transporting highly volatile liquids. NSB encouraged PHMSA to adopt improved leak detection standards and implement more stringent requirements for sensitive areas.

Response

PHMSA believes that the leak detection requirements in § 195.452(i)(3) can provide adequate protection for sensitive areas and is proposing to use those requirements as the basis for establishing requirements that would apply to hazardous liquid pipelines in all other locations. Under the current and proposed regulations, operators are required to consider several factors in selecting an appropriate leak detection system, including the characteristics and history of the affected pipeline, the capabilities of the available leak detection systems, and the location of emergency response personnel. PHMSA commissioned Kiefner and Associates, Inc., to perform a study on leak detection systems used by hazardous liquid operators. That study, titled ''Leak Detection Study,'' [4] was completed on December 10, 2012, and was submitted to Congress on December 27, 2012. PHMSA is considering, in a different rulemaking activity, whether to adopt additional or more stringent requirements for sensitive areas in response to this study.

Key Issues for New Leak Detection Standards

Comments

The trade associations, TxOGA, LMOGA, and API–AOPL, supported by an industry commenter, TransCanada Keystone, stated that PHMSA should identify issues that might adversely affect response times, including limiting the consequences for first responder deployment and allowing for the withdrawal of erroneous leak notifications. NAPSR, the only regulatory association to comment, found that any new standards should consider detection of small leaks in HCAs, maintenance, accuracy, transient conditions, system capabilities, and alarm management.

Three government/municipalities commented on this issue. DLA stated that any standards should address sensitivity, probability of false alarms, minimum leak detection capabilities, frequency, and be based on leak detection technology. MAWUC supported more stringent reporting and repair requirements. NSB indicated that PHMSA should require redundant leak detection systems for offshore lines. NSB also indicated the technology available for leak detection systems is vastly improved and industry should bear the burden to utilize these systems.

Response

The Pipeline Safety Laws contain a number of general factors that must be considered in prescribing new safety standards, including the reasonableness of the standard, the estimated benefits and costs, and the views and recommendations of the Technical Hazardous Liquid Pipeline Safety Standards Committee (49 U.S.C. 60102(b)). The Pipeline Safety Laws also contain specific factors that must be considered in prescribing certain safety standards, such as for smart pigs (49 U.S.C. 60102(f)) or low-stress hazardous liquid pipelines (49 U.S.C. 60102(k)).

In the case of leak detection, Congress has enacted prior statutory mandates that required the Secretary to survey and assess the need for additional safety standards. PHMSA and its predecessor agency, RSPA, complied with those mandates by producing two reports and promulgating additional safety standards for leak detection systems. Congress enacted a similar provision in section 8 of the Pipeline Safety Act of 2011, including a requirement that the Secretary submit a report to Congress that provides an analysis of the technical limitations of current leak detection systems and the practicability, safety benefits, and adverse consequence of establishing additional standards for the use of such systems.

The commenters identified several issues that should be considered in establishing new leak detection standards, including the need to minimize false alarms, to set appropriate volumetric thresholds, and to encourage the use of best available technologies.

Statistical Analyses of Leak Detection Requirements

PHMSA asked the public to comment on the availability of statistics on whether existing practices or standards on leak detection have contributed to reduced spill volumes and consequences.

Comments

One response submitted by API–AOPL, supported by TransCanada Keystone, LMOGA, and TxOGA, stated that the association was unaware of any recent statistics in regard to this topic. API–AOPL further indicated that PHMSA should allow time for recent regulatory changes to take effect on the regulated population.

Response

PHMSA's December 2007 report on leak detection systems noted that from 1997 to 2007 ''the median volume lost from hazardous liquid pipeline accidents dropped by more than half, from 200 to less than 100 barrels,'' and that ''the number of accidents declined by over a third.'' The report attributed that positive trend to the implementation of the pipeline IM requirements in § 195.452. However, the report also indicated that all of the available leak detection technologies have strengths and weakness, that some are only suitable for use on particular pipeline systems, and that establishing safety standards would require consideration of a number of factors.

Consideration of Industry Practices or Standards for Location of EFRDs

Part 195 requires that EFRDs be considered as potential mitigation measure on pipeline segments that could affect HCAs. In terms of §§ 195.450 and 195.452 the definition for check valve means a valve that permits fluid to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction. Likewise, remote control valve or RCV means any valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by the supervisory control and data acquisition (SCADA) system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.

Section 195.452(i)(4) further states that 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.

RSPA adopted the EFRD requirements in §§ 195.450 and 195.452 in a December 2000 final rule December 1, 2000, (65 FR 75378). Part 195 does not require that EFRDs be used on pipelines outside of HCAs, but § 195.260 does require that valves be installed at certain locations.

Congress included additional requirements for the use of automatic and remote-controlled shut-off valves in section 4 of the Pipeline Safety Act of 2011. That provision requires the Secretary, if appropriate and where economically, technically, and operationally feasible, to issue regulations for the use of automatic and remote-controlled shut-off valves on transmission lines that are newly constructed or entirely replaced. The Comptroller General is also required to perform a study on the effectiveness of these valves and to provide a report to Congress within one year of the date of the enactment of that legislation. PHMSA commissioned a study titled ''Studies for the Requirements of

[4] *http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_4A77C7A89CAA18E285898295888E3DB9C5924400/filename/Leak%20Detection%20Study.pdf*

Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines With Respect to Public and Environmental Safety,''[5] to help provide input on regulatory considerations regarding the feasibility and effectiveness of automatic and remote-control shutoff valves on hazardous liquid and natural gas transmission lines. The study was completed by the Oak Ridge National Laboratory on October 31, 2012, and it was submitted to Congress on December 27, 2012. PHMSA is using considerations from this study as it drafts a rulemaking titled ''Amendments to Parts 192 and 195 to require Valve installation and Minimum Rupture Detection Standards.''

Comments

PHMSA received comment on this issue from industry and trade associations. API–AOPL, TxOGA, LMOGA, and TransCanada Keystone reported that no industry standards currently address EFRD use, although ASME B31.4, ''Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids'' (2009), addresses mainline valves and requires remote operation and/or check valves in some instances. ASME B31.4 (2009) also has guidelines for mainline valves and requires remote and check valves, but is not currently incorporated by reference into part 195. Section 195.452 does require that operators identify the need for additional preventive and mitigation measures.

Response

PHMSA is studying issues concerning the development of additional safety standards for the use of EFRDs. PHMSA will consider the industry standards mentioned by the commenters, as well as the results of the September 1996 Volpe Report, the December 2007 Leak Detection Study, and the 2012 Oak Ridge National Laboratory study, for the purposes of any future rulemaking on the topic.

Adequacy of Existing Industry Practices or Standards for EFRDs

PHMSA asked for comment on the adequacy of existing industry practices or standards for EFRDs.

Comments

API–AOPL, TxOGA, LMOGA, and TransCanada Keystone stated that there is no current industry standard that sets a maximum spill volume or activation timing due to the widespread variation in pipeline dynamics; therefore, it would be difficult to establish a one-size-fits-all maximum spill volume requirement. API–AOPL suggests PHMSA should focus on prevention and response rather than spill size reduction through EFRDs.

Response

Section 195.452(i)(4) contains a requirement for the use of EFRDs on hazardous liquid pipelines that could affect an HCA. PHMSA agrees with the commenters that oil spill prevention and response are important to ensuring the safety of hazardous liquid pipelines, and believes that the appropriate use of EFRDs could be complementary to these efforts.

Consideration of Additional Standards Specifying the Location of EFRDs

Part 195 requires that EFRDs be considered as potential mitigation measure on pipeline segments that could affect HCAs, but it does not specify any particular location for the use of those devices. Operators must perform a risk analysis in determining whether and where to install EFRDs for such lines. Part 195 does not require that EFRDs be used on pipelines outside of HCAs. In the ANPRM, PHMSA asked for comment on whether additional standards should be developed to specify the location for EFRDs.

Comments

PHMSA received comments from four trade associations, one industry operator, and one regulatory association regarding prescriptive location of EFRDs. API–AOPL, TransCanada Keystone, LMOGA, and TxOGA indicated PHMSA should not specify location of EFRD placement for the reasons provided in response to previous questions. TPA agreed that no general criteria beyond those in existing regulations are appropriate because decisions on EFRD placement are driven by local factors. NAPSR supported the comments of the trade associations.

Response

PHMSA recognizes the commenters' concerns about mandating the installation of EFRDs in particular locations, but notes that other provisions in part 195 require that valves and other safety devices be installed in certain areas.

Mandated Use of EFRDs in All Locations

PHMSA requested comment on mandated use of EFRDs in all locations under PHMSA jurisdiction.

Comments

API–AOPL, TransCanada Keystone, LMOGA, and TxOGA indicated that a requirement to place EFRDs at predetermined locations or fixed intervals would be arbitrary, costly, and potentially counterproductive to pipeline safety. They noted that not all valves are mainline valves, and that a requirement for all valves to be remote would cause confusion. Many valves are at manned facilities. Some EFRDs are check valves, which are not amenable to remote control. API–AOPL noted that costs related to providing remote operation would vary based on proximity to power and communications, but that a December 2010 study by the Congressional Research Service estimated retrofit costs of $40K to $1.5M per valve. NAPSR agreed with the comments supplied by the trade associations and TransCanada Keystone. Finally, NSB stated EFRDs should be required on all pipelines PHMSA regulates with specific instruction on when and where EFRDs need to be utilized.

Response

PHMSA recognizes the commenters' concerns about mandating the installation of EFRDs in all locations and plans on continuing to study this issue.

Additional Research for Leak Detection

PHMSA requested comment regarding what leak detection technologies or methods require further research and development to demonstrate their efficacy.

Comments

PHMSA received no comments in response to this question.

D. Valve Spacing

Valve Spacing

The ANPRM asked whether PHMSA should repeal or modify the valve spacing requirements in part 195. Specifically, the ANPRM asked:

- For information on the average distance between valves;
- Whether valves are manually operated or remotely controlled;
- Whether additional standards should be adopted for evaluating valve spacing and location;
- Whether the maximum permissible distance between valves should be specified by regulation;
- Whether to adopt additional valve spacing requirements for hazardous liquid pipelines near HCAs;
- Whether additional valve spacing requirements should be adopted to protect narrower bodies of water;

[5] *http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_2C1A725B08C5F72F305689E943053A96232AB200/filename/Final%20Valve_Study.pdf*

• Whether all valves should be remotely controlled; and
• What the cost impact would be from requiring the installation of certain types of valves.

As discussed below, PHMSA is not proposing to adopt any additional standards for valve spacing, but will be considering that issue in complying with the various mandates in the Pipeline Safety Act of 2011.

Part 195 contains general construction requirements for valves. Specifically, § 195.258 provides that each valve must be installed in a location that is accessible to authorized employees and protected from damage or tampering. This section further states that submerged valves located offshore or in inland navigable waters must be marked, or located by conventional survey techniques, to facilitate quick location when operation of the valve is required.

PHMSA pipeline safety regulations found in section 195.260 indicate that a valve must be installed at certain locations. The locations named include on the suction end and the discharge end of a pump station or a breakout storage tank area in a manner that permits isolation of the tank area from other facilities and on each mainline at locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas. Three additional requirements for valve location in section 195.260 include each lateral takeoff from a trunk line, on each side of a water crossing that is more than 100 feet (30 meters) wide from high-water mark to high-water mark and on each side of a reservoir holding water for human consumption. The Department adopted these regulations in an October 1969 final rule October 4, 1969, (34 FR 15475).

As discussed in section 3, part 195 requires the use of EFRDs as a potential mitigation measure on pipeline segments that could affect HCAs. As also discussed in section 3, Congress included new provisions for the use of automatic and remote-controlled shut-off valves and leak detection systems in the Pipeline Safety Act of 2011.

Information on Average Distance Between Valves and Manual or Remote Operation

PHMSA asked the public to provide information on the average distance between valves and whether such valves are manually operated or remotely controlled.

Comments

The commenters did not provide any data on the average distance between valves, but did provide general information on valve spacing, location, and type. The commenters further noted that ASME B31.4, a consensus industry standard, includes a minimum valve spacing requirement of 7.5 miles for liquefied petroleum gas (LPG) and anhydrous ammonia pipelines in populated areas.

Specifically, API–AOPL, LMOGA, TxOGA, and TransCanada Keystone stated that valve spacing varies, that most mainline valves are manually operated, that check valves are used in certain cases, and that some remotely controlled valves had been added as a result of the IM requirements. API–AOPL also commented that ASME B31.4 provides additional requirements for LPG and anhydrous ammonia in populated areas, including a 7.5-mile spacing requirement for valves, but noted that PHMSA had not incorporated this version of B31.4 into part 195. NAPSR stated that proper valve location is more important than distance placement.

Response

Part 195 requires the installation of valves at certain locations, including pump stations, breakout tanks, mainlines, lateral lines, water crossings, and reservoirs. These requirements are generally directed toward achieving a particular result (*e.g.,* isolation of a facility, minimization of damage or pollution, etc.) and do not mandate that valves be installed at specific distances.

Part 195 does not prescribe whether manual or remotely controlled valves must be installed at particular locations, but does require consideration of check valves and remotely controlled valves under the EFRD requirements for pipelines that could affect an HCA. Section 4 of the Pipeline Safety Act of 2011 includes new requirements for evaluating and issuing additional regulations for the use of the automatic and remote-controlled shut-off valves.

PHMSA is not proposing to make any changes to the current valve spacing requirements at this time. A coordinated analysis will ensure that these issues are addressed in a way that maximizes the potential benefits and minimizes the potential burdens imposed by any new leak detection and valve spacing standards.

Adoption of Additional Standards for Valve Spacing and Location

PHMSA asked for comment on the adoption of additional standards for valve spacing and location.

Comments

TransCanada Keystone, API–AOPL, TxOGA, and LMOGA stated that the standards in §§ 195.260 and 195.452 are satisfactory. NAPSR supported the comments of API–AOPL. NSB recommended that DOT adopt standards for pipeline operators to use in evaluating valve spacing and location and identifying the maximum distance between valves.

Response

PHMSA is not proposing to adopt any additional standards for valve spacing and locations, but will be considering that issue in complying with the various mandates in the Pipeline Safety Act of 2011. PHMSA held a public meeting/workshop on valve spacing and locations on March 28, 2012. Information from this workshop was used in Oak Ridge National Laboratory's study, completed October 31, 2012, titled: ''Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety'' [6] to help determine the need for additional valve and location standards.

Additional Standards for Specifying the Maximum Distance Between Valves

PHMSA asked for public comment on whether part 195 should specify the maximum permissible distance between valves.

Comment

API–AOPL, TxOGA, LMOGA, TransCanada Keystone, and TPA opposed such a requirement and stated that valve spacing should be based on conditions and terrain. NAPSR also supported this position. NSB and MAWUC recommended the DOT adopt specific valve spacing standards. MAWUC stated that the criteria for valve spacing should be developed, but that the precise location of valves should not be made publicly available.

Response

Similarly, PHMSA is not proposing to adopt any additional standards for valve spacing at this time. PHMSA will be studying this issue and may make proposals concerning this topic in a later rulemaking.

[6] *http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_2C1A725B08C5F72F305689E943053A96232AB200/filename/Final%20Valve_Study.pdf*

Additional Requirements for Valve Spacing Near HCAs Beyond Those Required for EFRDs

PHMSA asked for public comment on whether part 195 should contain additional requirements for valve spacing in areas near HCAs beyond what is already required in § 195.452(i)(4) for EFRDs.

Comments

NSB encouraged PHMSA to adopt additional requirements for these areas. Taking a contrary position, API–AOPL, LMOGA, TxOGA, NAPSR, and TransCanada Keystone indicated that the current requirements adequately address the need for EFRDs and allow operators to assess the specific risks on each individual pipeline that could affect an HCA.

Response

PHMSA does not propose to make any changes to the regulations concerning the valve spacing at this time. PHMSA will be studying this issue and may make proposals concerning this topic in a later rulemaking.

Modifying the Scope of 49 CFR 195.260(e) To Include Narrower Bodies of Water

Section 195.260(e) requires the installation of a valve ''[o]n each side of a water crossing that is more than 100 feet (30 meters) wide from high-water mark to high-water mark unless the Administrator finds in a particular case that valves are not justified.'' The Department adopted that requirement in an October 1969 final rule October 4, 1969, (34 FR 15475) after adding the provision that allows the Administrator to find that the installation of a valve is not justified in specific cases. Such a finding requires the filing of a petition with the Administrator under 49 CFR 190.9.

Comments

API–AOPL, TxOGA, LMOGA, and TransCanada Keystone indicated that the current water crossing requirements are adequate, but that PHMSA could improve the regulation by allowing a risk-based approach for valve placement at water crossings and adding an exclusion for carbon dioxide pipelines.

TWS stated that PHMSA should require valves for waterways that are at least 25-feet in width and all feeder streams and creeks leading to such waterways. NSB supported the view of TWS and indicated the current 100-foot threshold for waterways should be reduced to 25 feet.

Response

As mentioned previously, PHMSA is proposing that all pipelines be inspected after extreme weather events or natural disasters. This is a natural extension of IM and ensures continued safe operations of the pipeline after abnormal operating conditions. Past events have strongly demonstrated that inspections after these events do prevent pipeline incidents from occurring. PHMSA is also proposing to require that all hazardous liquid pipelines have leak detection systems; that pipelines in areas that could affect HCAs be capable of accommodating ILIs within 20 years, unless the basic construction of the pipeline will not permit such an accommodation; that periodic assessments be performed of pipelines that are not already receiving such assessments under the IM program requirements; and that modified repair criteria be applied to pipelines in all locations. PHMSA will comply with the applicable provisions in the Pipeline Safety Act of 2011 before adopting any of these proposals in a final rule.

Adopting Safety Standards That Require All Valves To Be Remotely Controlled

PHMSA asked the public to comment on whether part 195 should include a requirement mandating the use of remotely-controlled valves in all cases.

Comments

API–AOPL, LMOGA, and TxOGA stated that PHMSA should not require remotely controlled valves in all cases. API–AOPL indicated that such a requirement would cause confusion as to which valves need to be operated manually, burden the industry with additional costs, and provide minimal safety benefits. API–AOPL submitted that the costs of retrofitting a valve to be remotely controlled varies widely from $40,000 to $1.5 million per valve as indicated in a recent report issued by the Congressional Research Service on pipeline safety and security. TPA further stated that the benefits of such requirements are dependent on local factors, and that additional requirements would add to pipeline system complexity and increase the probability of failure. Similarly, NAPSR stated that remote control valves should not be required, but that PHMSA should consider performance language for maximum response time to operate manual valves.

MAWUC indicated that PHMSA should consider requiring all valves to be remotely controlled, but that its decision should be based on an analysis of benefits and risks. NSB supported the use of remotely controlled valves in all instances. Coyle, a citizen, commented that PHMSA should promulgate regulatory language requiring remotely controlled valves for poison inhalation hazard pipelines.

Response

PHMSA notes that a risk-assessment must be performed in developing any new safety standards for the use of remotely controlled valves, and that any such standards will only be proposed upon a reasoned determination that the benefits justify the costs.

Requiring Installation of EFRDs To Protect HCAs

Section 195.452(i)(4) does not require the installation of an EFRD on all pipeline segments that could affect HCAs. Rather, it states that ''[i]f 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.'' It also states that an operator must at least consider a list of factors in making that determination.

Comments

API–AOPL, LMOGA, TxOGA and TransCanada Keystone stated that § 192.452 already requires EFRDs to be installed to protect a HCA if the operator finds, through a risk assessment, that an HCA is threatened. MAWUC commented that EFRDs should be required if they can limit a spill. Likewise, NSB supported the use of EFRDs for HCAs.

Response

PHMSA does not propose to make any changes to the regulations concerning the use of EFRDs at this time. PHMSA will be studying this issue and may make proposals concerning this topic in a later rulemaking.

Determining the Applicability of New Valve Location Requirements

In the ANPRM, PHMSA asked for public comment on how the agency should apply any new valve location requirements that are developed for hazardous liquid pipelines.

Comments

The trade association, API–AOPL, supported by TransCanada Keystone, LMOGA, and TxOGA, indicated that valve spacing requirements should not be changed, and that delineating new construction for any type of grandfathering purpose would be difficult and confusing. Requiring retrofitting of existing lines to meet any type of new requirement would be expensive for industry, create environmental impacts, potential construction accidents, and may cause interruption of service.

The regulatory association, NAPSR, suggested that exemptions to new valve location requirements should be based on the consequence of failure. Particular attention should be paid to spills into water as even a small spill can create a large problem.

Two government/municipalities commented. MAWUC indicated that there should be no waivers for valve spacing in HCAs due to the importance and interconnectivity of water supplies. NSB recommended that any new valve locations or remote actuation regulation be applied to new pipelines or existing pipelines that are repaired.

Response

PHMSA will continue to study valve spacing and automatic valve placement and may address these issues in a future rulemaking.

E. Repair Criteria Outside of HCAs

Repair Criteria

The ANPRM asked for public comment on whether to extend the IM repair criteria in § 195.452(h) to pipeline segments that are not located in HCAs. Specifically, the ANPRM asked ''Whether the IM repair criteria should apply to anomalous conditions discovered in areas outside of HCAs; whether the application of the IM repair criteria to non-HCA areas should be tiered on the basis of risk; what schedule should be applied to the repair of anomalous conditions discovered in non-HCA areas; whether standards should be specified for the accuracy and tolerance of inline inspection (ILI) tools; and whether additional standards should be established for performing ILI inspections with ''smart pigs''.

As discussed below, PHMSA is proposing to modify the provisions for making pipeline repairs. Additional conservatism will be incorporated into the existing IM repair criteria and an adjusted schedule for making immediate and non-immediate repairs will be established to provide greater uniformity. These criteria will also be made applicable to all pipelines, with an extended timeframe for making repairs outside of HCAs.

Application of IM Repair Criteria to Anomalous Conditions Discovered Outside of HCAs

In the ANPRM, PHMSA asked for comment on whether the IM repair criteria should apply to anomalous conditions discovered in areas outside of HCAs.

Comments

API–AOPL, supported by TransCanada Keystone, LMOGA, and TxOGA, stated that the repair criteria in or outside of HCAs should be the same. Likewise, the citizens' groups TWS and AKW echoed the comments of API–AOPL and further recommended that a phased-in time period should be utilized. NSB commented that anomalous conditions found during inspection in non-HCA areas should trigger expedited repair times.

Response

Section 195.452(h) specifies the actions that an operator must take to address integrity issues on hazardous liquid pipelines that could affect an HCA in the event of a leak or failure. Those actions include initiating temporary and long-term pressure reductions and evaluating and remediating certain anomalous conditions (*e.g.,* metal loss, dents, corrosion, cracks, gouges, grooves, and other any condition that could impair the integrity of the pipelines). Depending on the severity of the condition, such actions must be taken immediately, within 60 days, or within 180 days of the date of discovery.

Section 5 of the Pipeline Safety Act of 2011 requires the Secretary to perform an evaluation to determine if the IM requirements should be extended outside of and to submit a report to Congress with the result of that review. The Secretary is authorized to collect data for purposes of completing the evaluation and report to Congress. Section 5 also prohibits the issuance of any final regulations that would expand the IM requirements during a subsequent Congressional review period, subject to a savings clause that permits such action if a condition poses a risk to public safety, property, or the environment or is an imminent hazard and the regulations in question will address that risk or imminent hazard.

PHMSA is proposing to make certain modifications to the IM repair criteria and to establish similar repair criteria for pipeline segments that are not located in HCAs. Specifically, the repair criteria in § 195.452(h) would be amended to:

- Categorize bottom-side dents with stress risers as immediate repair conditions;
- Require immediate repairs whenever the calculated burst pressure is less than 1.1 times MOP;
- Eliminate the 60-day and 180-day repair categories; and
- Establish a new, consolidated 270-day repair category.

PHMSA is also proposing to adopt new requirements in § 195.422 that would: Apply the criteria in the immediate repair category in § 195.452(h) and Establish an 18-month repair category for hazardous liquid pipelines that are not subject to the IM requirements.

These changes will ensure that immediate action is taken to remediate anomalies that present an imminent threat to the integrity of hazardous liquid pipelines in all locations. Many anomalies that would not qualify as immediate repairs under the current criteria will meet that requirement as a result of the additional conservatism that will be incorporated into the burst pressure calculations. The new timeframes for performing other repairs will allow operators to remediate those conditions in a timely manner while allocating resources to those areas that present a higher risk of harm to the public, property, and the environment.

Use of a Tiered, Risk-Based Approach for Repairing Anomalous Conditions Discovered Outside of HCAs

In the ANPRM, PHMSA asked for comment on whether the application of the IM repair criteria to non-HCA areas should be tiered on the basis of risk.

Comments

API–AOPL, LMOGA, TPA, TxOGA, and TransCanada Keystone commented that PHMSA should not impose any sort of tiering to repair criteria because that is already inherent to the IM program. Scheduling flexibility would minimize disruption to the affected public, as well as the overall environmental impact, by preventing multiple excavation work on a given property. Requiring additional risk tiering of anomalies would not reduce safety risks to the public.

NAPSR, in contrast, commented that tiering should be utilized for repair criteria inside or outside of HCAs. NSB also indicated that risk tiering should be used. MAWUC supported risk tiering based on preselected criteria for HCAs.

Response

As previously discussed, PHMSA is proposing to apply new repair criteria for anomalous conditions discovered on hazardous liquid pipelines that are not located in HCAs. PHMSA is also proposing to establish two timeframes for performing those repairs: immediate repair conditions and 18-month repair conditions. If adopted as proposed, these changes will ensure the prompt remediation of anomalous conditions on all hazardous liquid pipeline segments, while allowing operators to allocate their resources to those areas that present a higher risk of harm to the public, property, and the environment.

Updating of Dent With Metal Loss Repair Criteria

Section 195.452(h) contains the criteria for repairing dents with metal loss on hazardous liquid pipeline segments that could affect an HCA in the event of a leak or failure. PHMSA asked for comment on whether advances in ILI tool capability justified an update in the dent-with-metal-loss repair criteria.

Comments

API–AOPL, LMOGA, TxOGA, and TransCanada Keystone indicated that the anticipated update to API 1160 will contain proposals to update the dent-with-metal-loss repair criterion. API–AOPL intends to support these proposals with data resulting from analyses of member company's experience measuring and characterizing metal loss in dents.

NAPSR encouraged PHMSA not to make the current standards less stringent even for dents without metal loss, citing a recent bottom side dent less than 6 inches that failed. NAPSR recommended strengthening the repair criteria for bottom-side dents in areas of heavy traffic or near swamps/bogs or in clay soils.

Response

As previously discussed, PHMSA is proposing to categorize bottom-side dents with stress risers as an immediate repair condition and to require immediate repairs when calculated burst pressure is less than 1.1 times MOP. These changes should ensure the prompt and effective remediation of anomalous conditions on all pipeline segments. With respect to API 1160, PHMSA will consider incorporating the 2013 edition in a future rulemaking.

Adoption of Explicit Standards To Account for Accuracy of ILI Tools

PHMSA requested comment on whether to adopt an explicit standard to account for the accuracy of ILI tools when comparing ILI data with repair criteria.

Comments

API–AOPL supports PHMSA's adoption of API 1163, the ''In-Line Inspection Systems Qualification Standard''. That standard includes a System Results Verification section, which describes methods to verify that the reported inspection results meet, or are within, the performance specification for the pipeline being inspected. That standard also requires that inconsistencies uncovered during the process validation be evaluated and resolved.

NAPSR supports the adoption of a standard because the IM process already is considering tool accuracy during the selection process and suggests revising the regulations to provide minimum standards of expected accuracy.

Response

In reviewing IM inspection data, PHMSA discovered that some operators were not considering the accuracy (*i.e.,* tolerance) of ILI tools when evaluating the results of the tool assessments. As a result, random variation within the recorded data led to both overcalls (*i.e.,* an anomaly was identified to be more extreme than it actually was) and under calls. Over calls are conservative, resulting in repair of some anomalies that might not actually meet repair criteria. Under calls are not and can result in anomalies that exceed specified repair criteria going un-remediated. Based on our review of inspection data, PHMSA has concluded that operators should be explicitly required to consider the accuracy of their ILI tools.

Specifically, under the proposed amendment to § 195.452(c)(1)(i) and the new provisions in § 195.416, operators will be required to consider tool tolerance and other uncertainties in evaluating ILI results for all hazardous liquid pipeline segments. Tool accuracy should include excavation findings and usage of unity plots of inline tool and excavation findings. When combined with the proposed changes to the repair criteria, the proposed tool tolerance requirement will ensure the prompt detection and remediation of anomalous conditions on all hazardous liquid pipelines. With respect to API 1163, as of January 2013, PHMSA is required by section 24 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 not to incorporate any consensus standards that are not available to the public, for free, on an internet Web site. PHMSA has sought a solution to this issue and as a result, all incorporated by reference standards in the pipeline safety regulations would be available for viewing to the public for free.

Additional Quality Control Standards for ILI Tools, Assessments, and Data Review

In the ANPRM, PHMSA asked if additional quality control standards are needed for conducting ILIs using smart pigs, the qualification of persons interpreting ILI data, the review of ILI results, and the quality and accuracy of ILI tool performance.

Comments

API–AOPL, LMOGA, TxOGA, and TransCanada Keystone commented that PHMSA should adopt API 1163 and American Society of Nondestructive Testing ILI PQ. These commenters stated that a certification program for analyzing ILI data would not add value to pipeline operators' IM programs, as operator experience has shown that these types of programs do not adequately reflect the highly technical nature of, and the intimate knowledge and experience of personnel practicing, IM programs. According to the commenters, there is no evidence that the current requirements and industry standards are leaving the public or environment at risk.

NAPSR indicated that if there is data to show this is an issue, PHMSA should adopt a standard. Additionally, a state could impose a more stringent standard based on prior experience. Both the NSB and MAWUC supported adoption of standards for ILI use.

Response

As noted in the response to the previous question, PHMSA is proposing to require operators to consider tool tolerance and other uncertainties in evaluating ILI results in complying with the IM requirements of § 195.452 and the proposed assessment requirement in § 195.416. PHMSA believes that this requirement and the proposed changes to the repair criteria will ensure the prompt detection and remediation of anomalous conditions (*e.g.,* metal loss, dents, corrosion, cracks, gouges, grooves) that could adversely affect the safe operation of a pipeline. PHMSA is proposing by a separate rulemaking via incorporation by reference available industry consensus standards for performing assessments of pipelines using ILI tools, internal corrosion direct assessment, and stress corrosion cracking direct assessment.

F. Stress Corrosion Cracking

In the October 2010 ANPRM, PHMSA asked for public comment on whether to adopt additional safety standards for stress corrosion cracking (SCC). SCC is cracking induced from the combined influence of tensile stress and a corrosive medium. Sections 195.553 and 195.588 and Appendix C of the Hazardous Liquid Pipeline Safety Standards contain provisions for the direct assessment of SCC, but do not include comprehensive requirements for preventing, detecting, and remediating that condition.

Specifically, PHMSA asked in the ANPRM whether:

• Any existing industry standards for preventing, detecting, and remediating SCC should be incorporated by reference;

• Any data or statistics are available on the effectiveness of these industry standards;

• Any data or statistics are available on the effectiveness of SCC detection tools and methodologies;

• Any tools or methods are available for detecting SCC associated with longitudinal pipe seams;

• An SCC threat analysis should be conducted for all pipeline segments;

• Any particular integrity assessment methods should be used when SCC is a credible threat; and

• Operators should be required to perform a periodic analysis of the effectiveness of their corrosion management programs.

Adoption of NACE Standard for Stress Corrosion Cracking Direct Assessment Methodology or Other Industry Standards

In the ANPRM, PHMSA asked for comment on whether the agency should incorporate any consensus industry standards for assessing SCC, including the NACE International (NACE) SP0204–2008 (formerly RP0204), Stress Corrosion Cracking (SCC) Direct Assessment Methodology. *http://www.nace.org/uploadedFiles/Committees/SP020408.pdf* (last accessed December 12, 2013) (stating that SP0204–2008 ''provides guidance for managing SCC by selecting potential pipeline segments, selecting dig sites within those segments, inspecting the pipe and collecting and analyzing data during the dig, establishing a mitigation program, defining the reevaluation interval, and evaluating the effectiveness of the SCC [direct assessment] process.'').

Comments

API–AOPL, TransCanada Keystone, TxOGA, and LMOGA stated that NACE SP0204–2008 provides an effective framework for the application of direct assessment, but does not sufficiently address other assessment methods, including ILI and hydrostatic testing. These commenters were also not aware of any industry statistics that directly correlate the application of that standard to the SCC detection or failure rate. These commenters stated the most appropriate standard for SCC assessment of hazardous liquid pipelines is the soon-to-be-released version of API Standard 1160, Managing System Integrity for Hazardous Liquid Pipelines.

Another trade association, TPA, stated that ''because [the NACE Standard] was just finished in 2008, PHMSA should wait at least 2–3 years more before attempting to assess the desirability of incorporating that standard into the regulations.''

One regulatory association, MAWUC, commented that PHMSA should adopt standards that address direct assessment, prevention, and remediation of SCC. The municipality/government entity, NSB, offered a similar comment.

Response

The commenters did not indicate that NACE SP0204–2008 would address the full lifecycle of SCC safety issues. Moreover, none of the commenters identified any other industry standards that would be appropriate for adoption at this time.

PHMSA recognizes that SCC is an important safety concern, but does not believe that further action can be taken based on the information available in this proceeding. PHMSA is establishing a team of experts to study this issue and will be holding a public forum on the development of SCC standards. Once that process is complete, PHMSA will consider whether to establish new safety standards for SCC. With respect to NACE SP0204–2008 PHMSA is proposing this standard by a separate rulemaking via incorporation by reference.

Identification of Standards and Practices for Prevention, Detection, Assessment and Remediation of SCC

PHMSA asked the public to identify any other standards and practices for the prevention, detection, assessment, and remediation of SCC.

Comments

API–AOPL, LMOGA, and TxOGA indicated that there are several good standards that address SCC, including API 1160, ASME STP–PT–011, Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas, and the Canadian Energy Pipeline Association (CEPA) Stress Corrosion Cracking Recommended Practices (CEPA SCC RP), but acknowledged that all of these standards have weaknesses.

The trade association, CEPA, also stated that the 2008 ASME STP–PT–011 should be considered. While written for gas pipelines, CEPA stated that this standard could be adapted to hazardous liquids.

Response

PHMSA appreciates the information provided by the commenters. PHMSA will be studying the SCC issue and will consider incorporating by reference suggested standards in future rulemakings.

Implementation of Canadian Energy Pipeline Association RP on SCC

CEPA is an organization that represents Canada's transmission pipeline companies. In 1997, CEPA developed its SCC Recommended Practice (RP) in response to a public inquiry by National Energy Board of Canada. In 2007, CEPA released an updated version of its SCC RP, *http://www.cepa.com/wp-content/uploads/2011/06/Stress-Corrosion-Cracking-Recommended-Practices-2007.pdf.* In the ANPRM, PHSMA asked for comment on the experience of operators in implementing CEPA's SCC RP.

Comments

API–AOPL, LMOGA, TxOGA, and TransCanada Keystone commented that the CEPA SCC RP provides the most thorough overview of the various assessment techniques, but is limited to near neutral SCC in terms of causal considerations. These commenters also stated that there are no industry statistics on the application of the CEPA RP SCC. CEPA and API–AOPL both indicated that companies continue to use the CEPA SCC RP as a guideline, but that there are no statistics on its use.

Response

PHMSA appreciates the comments provided on the use of the CEPA SCC RP and will consider that standard in its study of comprehensive safety requirements for SCC and in future rulemakings.

Effectiveness of SCC Detection Tools and Methods

PHMSA requested comment as to the effectiveness of current SCC detection tools and methods.

Comments

API–AOPL, supported by LMOGA, TxOGA, and TransCanada Keystone, stated that there are no industry statistics that directly correlate the application of the CEPA RP to the SCC detection or failure rate, but that the National Energy Board of Canada has noted the effectiveness of the CEPA RP for managing SCC. API–AOPL also stated the planned revisions of API 1160 and 1163 will address the current gaps regarding SCC in the standards and recommended practices relevant to liquid pipelines. One citizens' group, TWS, mentioned that gathering lines do not require corrosion prevention and that this should be required.

Response

PHMSA appreciates the comments provided on the effectiveness of SCC detection tools and methods and will be considering that information in evaluating comprehensive safety requirements for SCC and consider incorporating in future rulemakings.

IV. Section-by-Section Analysis

§ 195.1 Which pipelines are covered by this part?

Section 195.1(a) lists the pipelines that are subject to the requirements in part 195, including gathering lines that cross waterways used for commercial navigation as well as certain onshore gathering lines (*i.e.*, those that are located in a non-rural area, that meet the definition of a regulated onshore gathering line, or that are located in an inlet of the Gulf of Mexico). PHMSA has determined that additional information about unregulated gathering lines is needed to fulfill its statutory obligations. Accordingly, the NPRM extend the reporting requirements in subpart B of part 195 to all gathering lines (whether regulated, unregulated, onshore, or offshore) by adding a new paragraph (a)(5) to § 195.1.

§ 195.2 Definitions

Section 195.2 provides definitions for various terms used throughout part 195. On August 10, 2007, (72 FR 45002; Docket number PHMSA–2007–28136) PHMSA published a policy statement and request for comment on the transportation of ethanol, ethanol blends, and other biofuels by pipeline. PHMSA noted in the policy statement that the demand for biofuels was projected to increase in the future as a result of several federal energy policy initiatives, and that the predominant modes for transporting such commodities (*i.e.*, truck, rail, or barge) would expand over time to include greater use of pipelines. PHMSA also stated that ethanol and other biofuels are substances that ''may pose an unreasonable risk to life or property'' within the meaning of 49 U.S.C. 60101(a)(4)(B) and accordingly these materials constitute ''hazardous liquids'' for purposes of the pipeline safety laws and regulations.

PHMSA is now proposing to modify its definition of hazardous liquid in § 195.2. Such a change would make clear that the transportation of biofuel by pipeline is subject to the requirements of 49 CFR part 195.

PHMSA is also proposing to add a new definition of ''Significant Stress Corrosion Cracking.'' This new definition will provide criteria for determining when a probable crack defect in a pipeline segment must be excavated and repaired.

§ 195.11 What is a regulated rural gathering line and what requirements apply?

Section 195.11 defines and establishes the requirements that are applicable to regulated rural gathering lines. PHMSA has determined that these lines should be subject to the new requirements in the NPRM for the performance of periodic pipeline assessments and pipeline remediation and for establishing leak detection systems. Consequently, the NPRM would amend § 195.11 by adding paragraphs (b)(12) and (13) to ensure that these requirements are applicable to regulated rural gathering lines.

§ 195.13 What requirements apply to pipelines transporting hazardous liquids by gravity?

Section 195.13 will be added which subjects gravity lines to the same reporting requirements in subpart B of part 195 as other hazardous liquid pipelines. PHMSA has determined that additional information about gravity lines is needed to fulfill its statutory obligations.

§ 195.120 Passage of Internal Inspection Devices

Section 195.120 contains the requirements for accommodating the passage of internal inspection devices in the design and construction of new or replaced pipelines. PHMSA has decided that, in the absence of an emergency or where the basic construction makes that accommodation impracticable, a pipeline should be designed and constructed to permit the use of ILIs. Accordingly, the NPRM would repeal the provisions in the regulation that allow operators to petition the Administrator for a finding that the ILI compatibility requirement should not apply as a result of construction-related time constraints and problems. The other provisions in § 195.120 would be re-organized without altering the existing substantive requirements.

§ 195.134 Leak Detection

Section 195.134 contains the design requirements for computational pipeline monitoring leak detection systems. The NPRM would restructure the existing requirements into paragraphs (a) and (b) and add a new provision in paragraph (c) to ensure that all newly constructed pipelines are designed to include leak detection systems based upon standards in section 4.2 of API 1130 or other applicable design criteria in the standard.

§ 195.401 General Requirements

Section 195.401 prescribes general requirements for the operation and maintenance of hazardous liquid pipelines. PHMSA is proposing to modify the pipeline repair requirements in § 195.401(b). Paragraph (b)(1) will be modified to reference the new timeframes in § 195.422 for performing non-IM repairs. The requirements in paragraph (b)(2) for IM repairs will be retained without change. A new paragraph (b)(3) will be added, however, to clearly require operators to consider the risk to people, property, and the environment in prioritizing the remediation of any condition that could adversely affect the safe operation of a pipeline system, including those covered by the timeframes specified in §§ 195.422(d) and (e) and 195.452(h).

§ 195.414 Inspections of Pipelines in Areas Affected by Extreme Weather, a Natural Disaster, and Other Similar Events

Extreme weather, natural disasters and other similar events can affect the safe operation of a pipeline. Accordingly, the NPRM would establish a new regulation in § 195.414 that would require operators to perform inspections after these events and to take appropriate remedial actions.

§ 195.416 Pipeline Assessments

Periodic assessments, particularly with ILI tools, provide critical information about the condition of a pipeline, but are only currently required under IM requirements in §§ 195.450 through 195.452. PHMSA has determined that operators should be required to have the information that is needed to promptly detect and remediate conditions that could affect the safe operation of pipelines in all areas. Accordingly, the NPRM would establish a new regulation in § 195.416 that requires operators to perform an assessment of pipelines that are not already subject to the IM requirements at least once every 10 years. The regulation would require that these assessments be performed with an ILI tool, unless an operator demonstrates and provides 90-days prior notice that a pipeline is not capable of accommodating such a device and that an alternative method will provide a substantially equivalent understanding of its condition.

The regulation would also require that the results of these assessments be reviewed by a person qualified to determine if any conditions exist that could affect the safe operation of a pipeline; that such determinations be made promptly, but no later than 180 days after the assessment; that any unsafe conditions be remediated in accordance with the new requirements in § 195.422 of the NPRM; and that all relevant information about the pipeline be considering in complying with the requirements of § 195.416.

§ 195.422 Pipeline Remediation

Section 195.422 contains the requirements for performing pipeline repairs. PHMSA has determined that new criteria should be established for remediating conditions that affect the safe operation of a pipeline. The NPRM would add a new paragraph (a) specifying that the provisions in the regulation are applicable to pipelines that are not subject to the IM requirements in § 195.452 (*e.g.*, not in HCAs). Paragraphs (b) and (c) would contain the existing requirements in the regulation, including the general duty clause for ensuring public safety and the provision noting the applicability of the design and construction requirements to piping and equipment used in performing pipeline repairs. Paragraph (d) would establish a new remediation schedule based on the analogous provisions in the IM requirements for performing immediate and 18-month repairs, and paragraph (e) would contain a residual provision for remediating all other conditions.

§ 195.444 Leak Detection

Section 195.444 contains the operation and maintenance requirements for Computational Pipeline Monitoring leak detection systems. PHMSA is proposing that all pipelines should have leak detection systems. Therefore, the NPRM would reorganize the existing requirements of the regulation into paragraphs (a) and (c), and add a new general provision in paragraph (b) that would require operators to have leak detection systems on all pipelines and to consider certain factors in determining what kind of system is necessary to protect the public, property, and the environment.

Section 195.452 Pipeline Integrity Management in High Consequence Areas

Section 195.452 contains the IM requirements for hazardous liquid pipelines that could affect a HCA in the event of a leak or failure. The NPRM would clarify the applicability of the deadlines in paragraph (b) for the development of a written program for new pipelines, regulated rural gathering lines, and low-stress pipelines in rural areas. Paragraph (c)(1)(i)(A) would also be amended to ensure that operators consider uncertainty in tool tolerance in reviewing the results of ILI assessments. Paragraph (d) would be amended to eliminate obsolete deadlines for performing baseline assessments and to clarify the requirements for newly-identified HCAs. Paragraph (e)(1)(vii) is amended to include local environmental factors that might affect pipeline integrity. Paragraph (g) would be amended to expand upon the factors and criteria that operators must consider in performing the information analysis that is required in periodically evaluating the integrity of covered pipeline segments. Paragraph (h)(1) would also be amended by modifying the criteria, and establishing a new, consolidated timeframe, for performing immediate and 270-day pipeline repairs based on the information obtained as a result of ILI assessments or through an information analysis of a covered segment.

PHMSA is also proposing to amend the existing ''discovery of condition'' language in the pipeline safety regulations. The revised § 195.452(h)(2) will require, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators must notify PHMSA and provide an expected date when adequate information will become available. Paragraphs 195.452(h)(4)(i)(E) and (F) are also added to address issues of significant stress corrosion cracking and selective seam corrosion.

PHMSA proposes further changes to § 195.452. These changes include paragraph (j) which would be amended to establish a new provision for verifying the risk factors used in identifying covered segments on at least an annual basis, not to exceed 15 months. A new paragraph (n) would also be added to require that all pipelines in areas that could affect an HCA be made capable of accommodating ILI tools within 20 years, unless the basic construction of a pipeline will not permit that accommodation or the existence of an emergency renders such an accommodation impracticable. Paragraph (n) would also require that pipelines in newly-identified HCAs after the 20-year period be made capable of accommodating ILIs within five years of the date of identification or before the performance of the baseline assessment, whichever is sooner. Finally, an explicit reference to seismicity will be added to factors that must be considered in establishing assessment schedules under paragraph (e), for performing information analyses under paragraph (g), and for implementing preventive and mitigative measures under paragraph (i).

V. Regulatory Notices

A. Executive Order 12866, Executive Order 13563, and DOT Regulatory Policies and Procedures

Executive Orders 12866 and 13563 require agencies to regulate in the ''most cost-effective manner,'' to make a ''reasoned determination that the benefits of the intended regulation justify its costs,'' and to develop regulations that ''impose the least burden on society.'' This action has been determined to be significant under Executive Order 12866 and the Department of Transportation's Regulatory Policies and Procedures. It has been reviewed by the Office of Management and Budget in accordance with Executive Order 13563 (Improving Regulation and Regulatory Review) and Executive Order 12866 (Regulatory Planning and Review) and is consistent with the requirements in both orders.

In the regulatory analysis, we discuss the alternatives to the proposed requirements and, where possible, provide estimates of the benefits and costs for specific regulatory requirements in the eight areas. The regulatory analysis provides PHMSA's best estimate of the impact of the separate requirements. The chart below summarizes the cost/benefit analysis:

ANNUALIZED COSTS AND BENEFITS BY REQUIREMENT AREA DISCOUNTED AT 7 PERCENT

Requirement area	Costs	Benefits	Net benefits
1. Extend certain reporting requirements to all hazardous liquid (HL) gravity lines.	$900	Benefits not quantified, but expected to justify costs.	Expected to be positive.

ANNUALIZED COSTS AND BENEFITS BY REQUIREMENT AREA DISCOUNTED AT 7 PERCENT—Continued

Requirement area	Costs	Benefits	Net benefits
2. Extend certain reporting requirements to all hazardous liquid (HL) gathering lines.	23,300	Benefits not quantified but expected to justify the costs.	Expected to be positive.
3. Require inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events, as well as appropriate remedial action if a condition that could adversely affect the safe operation of a pipeline is discovered.	1.5 million	3.5 to 10.4 million	2.0 to 8.9 million
4. Require periodic assessments of pipelines that are not already covered under the IM program requirements using an in-line inspection tool (or demonstrate to the satisfaction of PHMSA that the pipeline is not capable of using this tool).	16.7 million	17.7 million Range 9.4–26.0 million	1 million Range (–)7.3–9.3 million Expected to be positive even at the low end of the benefit range if unquantified benefits are included.
5. Require use of leak detection systems (LDS) on new HL pipelines located in non-HCAs to mitigate the effects of failures that occur outside of HCAs.	Not quantified but expected to be minimal.	Not quantified, but expected to justify the minimal costs.	Not quanitified, but positive qualitative benefits.
6. Modify the IM repair criteria, both by expanding the list of conditions that require immediate remediation, consolidating the timeframes for remediating all other conditions, and making explicit deadlines for repairs on non-IM pipeline.	Not quantified, but expected to be minimal.	Not quantified, but expected to justify the minimal costs.	Not quantified, but expected to be minimal.
7. Increase the use of inline inspection (ILI) tools by requiring that any pipeline that could affect an HCA be capable of accommodating these devices within 20 years, unless its basic construction will not permit that accommodation.	1.0 million	12.2 million	11.2 million
8. Clarify and resolve inconsistencies regarding deadlines, and information analyses for IM Plans t.	3.2 million	10.0 million	6.8 million.

Overall, factors such as increased safety, public confidence that all pipelines are regulated, quicker discovery of leaks and mitigation of environmental damages, and better risk management are expected to yield benefits that are in excess of the cost. PHMSA seeks comment on the Preliminary Regulatory Evaluation, its approach, and the accuracy of its estimates of costs and benefits. A copy of the Preliminary Regulatory evaluation has been placed in the docket.

B. Executive Order 13132: Federalism

This NPRM has been analyzed in accordance with the principles and criteria contained in Executive Order 13132 (''Federalism''). This NPRM does not propose any regulation that has substantial direct effects on the states, the relationship between the national government and the states, or the distribution of power and responsibilities among the various levels of government. It does not propose any regulation that imposes substantial direct compliance costs on state and local governments. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply. Nevertheless, PHMSA has and will continue to consult extensively with state regulators including NAPSR to ensure that any state concerns are taken into account.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980 (Pub. L. 96–354) (RFA) establishes ''as a principle of regulatory issuance that agencies shall endeavor, consistent with the objectives of the rule and of applicable statutes, to fit regulatory and informational requirements to the scale of the businesses, organizations, and governmental jurisdictions subject to regulation. To achieve this principle, agencies are required to solicit and consider flexible regulatory proposals and to explain the rationale for their actions to assure that such proposals are given serious consideration.''

The RFA covers a wide range of small entities, including small businesses, not-for-profit organizations, and small governmental jurisdictions. Agencies must perform a review to determine whether a rule will have a significant economic impact on a substantial number of small entities. If the agency determines that it will, the agency must prepare a regulatory flexibility analysis as described in the RFA.

However, if an agency determines that a rule is not expected to have a significant economic impact on a substantial number of small entities, section 605(b) of the RFA provides that the head of the agency may so certify and a regulatory flexibility analysis is not required. The certification must include a statement providing the factual basis for this determination, and the reasoning should be clear.

PHMSA performed a screening analysis of the potential economic impact on small entities. The screening analysis is available in the docket for the rulemaking. PHMSA estimates that the proposed rule would impact fewer than 100 small hazardous liquid pipeline operators, and that the majority of these operators would experience annual compliance costs that represent less than 1% of annual revenues. Less than 20 small operators would incur annual compliance costs that represent greater than 1% of annual revenues; less than 10 would incur annual compliance costs of greater than 3% of annual revenues; and none would incur compliance costs of more than 20% of annual revenues. PHMSA determined that these impacts results do not represent a significant impact for a substantial number of small hazardous liquid pipeline operators. Therefore, I certify that this action, if promulgated, will not have a significant economic impact on a substantial number of small entities.

D. National Environmental Policy Act

PHMSA analyzed this NPRM in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR parts 1500 through 1508), and DOT Order 5610.1C, and has preliminarily determined that this action will not significantly affect the quality of the human environment. A preliminary environmental assessment of this rulemaking is available in the docket and PHMSA invites comment on environmental impacts of this rule, if any.

E. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This NPRM has been analyzed in accordance with the principles and criteria contained in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments''). Because this NPRM does not have Tribal implications and does not impose substantial direct compliance costs on Indian Tribal governments, the funding and consultation requirements of Executive Order 13175 do not apply.

F. Paperwork Reduction Act

Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. PHMSA estimates that the proposals in this rulemaking will add a new information collection and impact several approved information collections titled:

''Transportation of Hazardous Liquids by Pipeline: Recordkeeping and Accident Reporting'' identified under Office of Management and Budget (OMB) Control Number 2137–0047;

''Reporting Safety-Related Conditions on Gas, Hazardous Liquid, and Carbon Dioxide Pipelines and Liquefied Natural Gas Facilities'' identified under OMB Control Number 2137–0578;

''Integrity Management in High Consequence Areas for Operators of Hazardous Liquid Pipelines'' identified under OMB Control Number 2137–0605 and;

''Pipeline Safety: New Reporting Requirements for Hazardous Liquid Pipeline Operators: Hazardous Liquid Annual Report'' identified under OMB Control Number 2137–0614.

Based on the proposals in this rulemaking, PHMSA will submit an information collection revision request to OMB for approval based on the requirements in this NPRM. The information collection is contained in the pipeline safety regulations, 49 CFR parts 190 through 199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burden for the following information collections are estimated to be revised as follows:

1. *Title:* Transportation of Hazardous Liquids by Pipeline: Recordkeeping and Accident Reporting.

OMB Control Number: 2137–0047.

Current Expiration Date: April 30, 2014.

Abstract: This information collection covers the collection of information from owners and operators of Hazardous Liquid Pipelines. To ensure adequate public protection from exposure to potential hazardous liquid pipeline failures, PHMSA collects information on reportable hazardous liquid pipeline accidents. Additional information is also obtained concerning the characteristics of an operator's pipeline system. As a result of this NPRM, 5 gravity line operators and 23 gathering line operators would be required to submit accident reports to PHMSA on occasion. These 28 additional operators will also be required to keep mandated records. This information collection is being revised to account for the additional burden that will be incurred by these newly regulated entities. Operators currently submitting annual reports will not be otherwise impacted by this NPRM.

Affected Public: Owners and operators of Hazardous Liquid Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 881.

Total Annual Burden Hours: 55,455.

Frequency of Collection: On occasion.

2. *Title:* Reporting Safety-Related Conditions on Gas, Hazardous Liquid, and Carbon Dioxide Pipelines and Liquefied Natural Gas Facilities.

OMB Control Number: 2137–0578.

Current Expiration Date: May 31, 2014.

Abstract: 49 U.S.C. 60102 requires each operator of a pipeline facility (except master meter operators) to submit to DOT a written report on any safety-related condition that causes or has caused a significant change or restriction in the operation of a pipeline facility or a condition that is a hazards to life, property or the environment. As a result of this NPRM, approximately 5 gravity line operators and 23 gathering line operators will be required to adhere to the Safety-Related Condition reporting requirements. This information collection is being revised to account for the additional burden that will be incurred by newly regulated entities. Operators currently submitting annual reports will not be otherwise impacted by this rule.

Affected Public: Owners and operators of Hazardous Liquid Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 178.

Total Annual Burden Hours: 1,020.

Frequency of Collection: On occasion.

3. *Title:* Integrity Management in High Consequence Areas for Operators of Hazardous Liquid Pipelines.

OMB Control Number: 2137–0605.

Current Expiration Date: November 30, 2016.

Abstract: Owners and operators of Hazardous Liquid Pipelines are required to have continual assessment and evaluation of pipeline integrity through inspection or testing, as well as remedial preventive and mitigative actions. As a result of this NPRM, operators not currently under IM plans will be required to adhere to the repair criteria currently required for operators who are under IM plans. In conjunction with this requirement, operators who are not able to make the necessary repairs within 180 days of the infraction will be required to notify PHMSA in writing. PHMSA estimates that only 1% of repair reports will require more than 180 days. Accordingly, PHMSA approximates that 75 reports per year will fall within this category.

Affected Public: Owners and operators of Hazardous Liquid Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 278.

Total Annual Burden Hours: 325,508.

Frequency of Collection: Annually.

4. *Title:* Pipeline Safety: New Reporting Requirements for Hazardous Liquid Pipeline Operators: Hazardous Liquid Annual Report.

OMB Control Number: 2137–0614.

Current Expiration Date: April 30, 2014.

Abstract: Owners and operators of hazardous liquid pipelines are required to provide PHMSA with safety related documentation relative to the annual operation of their pipeline. The provided information is used compile a national pipeline inventory, identify safety problems, and target inspections. As a result of this NPRM, approximately 5 gravity line operators and 23 gathering line operators will be required to submit annual reports to PHMSA. This information collection is being revised to account for the additional burden that will be incurred. Operators currently submitting annual reports will not be otherwise impacted by this rule.

Affected Public: Owners and operators of Hazardous Liquid Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 475.

Total Annual Burden Hours: 8,567.

Frequency of Collection: Annually.

5. *Title:* Pipeline Safety: Notification Requirements for Hazardous Liquid Operators.

OMB Control Number: New OMB Control No.

Current Expiration Date: TBD.

Abstract: Owners and operators of non-High Consequence Area hazardous liquid pipelines will be required to provide PHMSA with notifications when unable to assess their pipeline via an in-line inspection.

Affected Public: Owners and operators of Hazardous Liquid Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 10.

Total Annual Burden Hours: 10.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Dow or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE., Washington, DC 20590–0001, Telephone (202) 366–4595.

G. Privacy Act Statement

Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477), or at *http://www.regulations.gov.*

H. Regulation Identifier Number (RIN)

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 in 49 CFR Part 195

Incorporation by reference, Integrity management, Pipeline safety.

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

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 1. The authority citation for part 195 is revised to read as follows:

Authority: 49 U.S.C. 5103, 60101, 60102, 60104, 60108, 60109, 60116, 60118, 60131, 60131, 60137, and 49 CFR 1.97.

■ 2. In § 195.1, paragraph (a)(5) is added, paragraph (b)(2) is removed, and paragraphs (b)(3) through (10) are re-designated as (b)(2) through (9).

The addition reads as follows:

§ 195.1 Which pipelines are covered by this part?

(a) * * *

* * * * *

(5) For purposes of the reporting requirements in subpart B of this part, any gathering line not already covered under paragraphs (a)(1), (2), (3) or (4) of this section.

* * * * *

■ 3. In section 195.2, the definition for ''*Hazardous liquid''* is revised and a definition of ''*Significant stress corrosion cracking''* is added in alphabetical order to read as follows:

§ 195.2 Definitions.

* * * * *

Hazardous liquid means petroleum, petroleum products, anhydrous ammonia or non-petroleum fuel, including biofuel that is flammable, toxic, or corrosive or would be harmful to the environment if released in significant quantities.

* * * * *

Significant stress corrosion cracking means a stress corrosion cracking (SCC) cluster in which the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS.

* * * * *

■ 4. In section 195.11, add paragraphs (b)(12) and (13) to read as follows:

§ 195.11 What is a regulated rural gathering line and what requirements apply?

* * * * *

(b) * * *

(12) Perform pipeline assessments and remediation as required under §§ 195.416 and 195.422.

(13) Establish a leak detection system in compliance with §§ 195.134 and 195.444.

* * * * *

■ 5. Section 195.13 is added to subpart A to read as follows:

§ 195.13 What reporting requirements apply to pipelines transporting hazardous liquids by gravity?

(a) *Scope.* This section applies to pipelines transporting hazardous liquids by gravity as of [effective date of the final rule].

(b) *Annual, accident and safety related reporting.* Comply with the reporting requirements in subpart B of this part by [date 6 months after effective date of the final rule].

■ 6. Section 195.120 is revised to read as follows:

§ 195.120 Passage of internal inspection devices.

(a) *General.* Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each main line section of a pipeline where the line pipe, valve, fitting or other line component is replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

(b) *Exceptions.* This section does not apply to:

(1) Manifolds;

(2) Station piping such as at pump stations, meter stations, or pressure reducing stations;

(3) Piping associated with tank farms and other storage facilities;

(4) Cross-overs;

(5) Pipe for which an instrumented internal inspection device is not commercially available; and

(6) Offshore pipelines, other than main lines 10 inches (254 millimeters) or greater in nominal diameter, that transport liquids to onshore facilities.

(c) *Impracticability.* An operator may file a petition under § 190.9 for a finding that the requirements in paragraph (a) should not be applied to a pipeline for reasons of impracticability.

(d) *Emergencies.* An operator need not comply with paragraph (a) of this section in constructing a new or replacement segment of a pipeline in an emergency. Within 30 days after discovering the emergency, the operator must file a petition under § 190.9 for a finding that requiring the design and construction of the new or replacement pipeline segment to accommodate passage of instrumented internal inspection devices would be impracticable as a result of the emergency. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify the new or replacement pipeline segment to allow passage of instrumented internal inspection devices.

■ 7. Section 195.134 is revised to read as follow:

§ 195.134 Leak detection.

(a) *Scope.* This section applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid).

(b) *General.* Each pipeline must have a system for detecting leaks that complies with the requirements in § 195.444.

(c) *CPM leak detection systems.* A new computational pipeline monitoring (CPM) leak detection system or replaced component of an existing CPM system must be designed in accordance with the requirements in section 4.2 of API RP 1130 (incorporated by reference, see § 195.3) and any other applicable design criteria in that standard.

■ 8. In § 195.401, the introductory text of paragraph (b) and paragraph (b)(1) are revised and paragraph (b)(3) is added to read as follows:

§ 195.401 General requirements.

* * * * *

(b) An operator must make repairs on its pipeline system according to the following requirements:

(1) *Non integrity management repairs.* Whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline not covered under § 195.452, it must correct the condition as prescribed in § 195.422. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

* * * * *

(3) *Prioritizing repairs.* An operator must consider the risk to people, property, and the environment in prioritizing the correction of any conditions referenced in paragraphs (b)(1) and (2) of this section.

* * * * *

■ 9. Section 195.414 is added to read as follows:

§ 195.414 Inspections of pipelines in areas affected by extreme weather, a natural disaster, and other similar events.

(a) *General.* Following an extreme weather event such as a hurricane or flood, an earthquake, a natural disaster, or other similar event, an operator must inspect all potentially affected pipeline facilities to ensure that no conditions exist that could adversely affect the safe operation of that pipeline.

(b) *Inspection method.* An operator must consider the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the inspection required under paragraph (a) of this section.

(c) *Time period.* The inspection required under paragraph (a) of this section must occur within 72 hours after the cessation of the event, or as soon as the affected area can be safely accessed by the personnel and equipment required to perform the inspection as determined under paragraph (b) of this section.

(d) *Remedial action.* An operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required under paragraph (a) of this section. Such actions might include, but are not limited to:

(1) Reducing the operating pressure or shutting down the pipeline;

(2) Modifying, repairing, or replacing any damaged pipeline facilities;

(3) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;

(4) Performing additional patrols, surveys, tests, or inspections;

(5) Implementing emergency response activities with Federal, State, or local personnel; and

(6) Notifying affected communities of the steps that can be taken to ensure public safety.

■ 10. Section 195.416 is added to read as follows:

§ 195.416 Pipeline assessments.

(a) *Scope.* This section applies to pipelines that are not subject to the integrity management requirements in § 195.452.

(b) *General.* An operator must perform an assessment of a pipeline at least once every 10 years, or as otherwise necessary to ensure public safety.

(c) *Method.* The assessment required under paragraph (b) of this section must be performed with an in-line inspection tool or tools capable of detecting corrosion and deformation anomalies, including dents, cracks, gouges, and grooves, unless an operator:

(i) Demonstrates that the pipeline is not capable of accommodating an inline inspection tool; and that the use of an alternative assessment method will provide a substantially equivalent understanding of the condition of the pipeline; and

(ii) Notifies the Office of Pipeline Safety (OPS) 90 days before conducting the assessment by:

(A) Sending the notification, along with the information required to demonstrate compliance with paragraph (c)(i) of this section, to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590; or

(B) Sending the notification, along with the information required to demonstrate compliance with paragraph (c)(i) of this section, to the Information Resources Manager by facsimile to (202) 366–7128.

(d) *Data analysis.* A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under paragraph (b) of this section to determine if a condition could adversely affect the safe operation of the pipeline. Uncertainties in any reported results (including tool tolerance) must be considered as part of that analysis.

(e) *Discovery of condition.* For purposes of § 195.422, discovery of a condition occurs when an operator has adequate information to determine that a condition exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition and make the determination required under paragraph (d) of this section, unless 180-days is impracticable as determined by PHMSA.

(f) *Remediation.* An operator must comply with the requirements in § 195.422 if a condition that could adversely affect the safe operation of a pipeline is discovered in complying with paragraphs (d) and (e) of this section.

(g) *Consideration of information.* An operator must consider all relevant information about a pipeline in complying with the requirements in paragraphs (a) through (f) of this section.

■ 11. Section 195.422 is revised to read as follows:

§ 195.422 Pipeline remediation.

(a) *Scope.* This section applies to pipelines that are not subject to the integrity management requirements in § 195.452.

(b) *General.* Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made so as to prevent damage to persons, property, or the environment.

(c) *Replacement.* An operator may not use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

(d) *Remediation schedule.* An operator must complete the remediation of a condition according to the following schedule:

(1) *Immediate repair conditions.* An operator must repair the following conditions immediately upon discovery:

(i) Metal loss greater than 80% of nominal wall regardless of dimensions.

(ii) A calculation of the remaining strength of the pipe shows a burst pressure less than 1.1 times the maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991) or AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)) (incorporated by reference, see § 195.3.

(iii) A dent located anywhere on the pipeline that has any indication of metal loss, cracking or a stress riser.

(iv) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter.

(v) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(vi) Any indication of significant stress corrosion cracking (SCC).

(vii) Any indication of selective seam weld corrosion (SSWC).

(2) Until the remediation of a condition specified in paragraph (d)(1) of this section is complete, an operator must:

(i) Reduce the operating pressure of the affected pipeline using the formula specified in paragraph 195.422(d)(3)(iv) or;

(ii) Shutdown the affected pipeline.

(3) *18-month repair conditions.* An operator must repair the following conditions within 18 months of discovery:

(i) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

(ii) A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).

(iii) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(iv) A calculation of the remaining strength of the pipe at the anomaly shows a safe operating pressure that is less than the MOP at that location. Provided the safe operating pressure includes the internal design safety factors in § 195.106 in calculating the pipe anomaly safe operating pressure, suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991)) or AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)) (incorporated by reference, see § 195.3).

(v) An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.

(vi) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.

(vii) A potential crack indication that when excavated is determined to be a crack.

(viii) Corrosion of or along a seam weld.

(ix) A gouge or groove greater than 12.5% of nominal wall.

(e) *Other conditions.* Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system within a reasonable time.

■ 12. Section 195.444 is revised to read as follows:

§ 195.444 Leak detection.

(a) *Scope.* This section applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid).

(b) *General.* A pipeline must have a system for detecting leaks. An operator must evaluate and modify, as necessary, the capability of its leak detection system to protect the public, property, and the environment. An operator's evaluation must, at least, consider the following factors—length and size of the pipeline, type of product carried, the swiftness of leak detection, location of nearest response personnel, and leak history.

(c) *CPM leak detection systems.* Each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline must comply with API RP 1130 (incorporated by reference, see § 195.3) in operating, maintaining, testing, record keeping, and dispatcher training of the system.

■ 13. In § 195.452:

■ a. Revise paragraphs (a), (b)(1), introductory text of paragraph (c)(1)(i), (c)(1)(i)(A), (d), (e)(1)(vii), (g), introductory text of (h)(1), (h)(2), and (h)(4);

■ b. Revise paragraph (i)(2)(viii) by removing the period at the end of the last sentence and adding in its place a '';'' and add paragraph (i)(2)(ix);

■ c. Revise paragraphs (j)(1) and (2);

■ d. Add paragraph (n).

The revisions and additions read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

(a) *Which pipelines are covered by this section?* This section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area, unless the operator demonstrates that a worst case discharge from the pipeline could not affect the area. (Appendix C of this part provides guidance on determining if a pipeline could affect a high consequence area.) Covered pipelines are categorized as follows:

(1) Category 1 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated a total of 500 or more miles of pipeline subject to this part.

(2) Category 2 includes pipelines existing on May 29, 2001, that were owned or operated by an operator who owned or operated less than 500 miles of pipeline subject to this part.

(3) Category 3 includes pipelines constructed or converted after May 29, 2001, low-stress pipelines in rural areas under § 195.12.

(b) * * *

(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column:

Pipeline	Date
Category 1	March 31, 2002.
Category 2	February 18, 2003.
Category 3	Date the pipeline begins operation or as provided in § 195.12.

* * * * *

(c) * * *

(1) * * *

(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by In Line Inspection tool unless it is impracticable, then use methods (B), (C) or (D) of this paragraph. The methods an operator selects to assess low frequency electric resistance welded pipe, or lap welded pipe, or pipe with a seam factor less than 1.0 as defined in § 195.106(e) or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(A) Internal inspection tool or tools capable of detecting corrosion, and deformation anomalies including dents, cracks (pipe body and weld seams), gouges and grooves. An operator using this method must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or equivalent for determining uncertainties) in identifying anomalies;

* * * * *

(d) *When must operators complete baseline assessments?*

(1) *All pipelines.* An operator must complete the baseline assessment before the pipeline begins operation.

(2) *Newly-identified areas.* If an operator obtains information (whether from the information analysis required under paragraph (g) of this section, Census Bureau maps, or any other source) demonstrating that the area around a pipeline segment has changed to meet the definition of a high consequence area (*see* § 195.450), that area must be incorporated into the operator's baseline assessment plan within one year from the date that the information is obtained. An operator must complete the baseline assessment of any pipeline segment that could affect a newly-identified high consequence area within five years from the date the area is identified.

* * * * *

(e) * * *

(1) * * *

(vii) Local environmental factors that could affect the pipeline (*e.g.,* seismicity, corrosivity of soil, subsidence, climatic);

* * * * *

(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (*see* paragraph (j) of this section), an operator must analyze all available information about the integrity of its entire pipeline and the consequences of a possible failure along the pipeline. This analysis must:

(1) Integrate information and attributes about the pipeline which include, but are not limited to:

(i) Pipe diameter, wall thickness, grade, and seam type;

(ii) Pipe coating including girth weld coating;

(iii) Maximum operating pressure (MOP);

(iv) Endpoints of segments that could affect high consequence areas (HCAs);

(v) Hydrostatic test pressure including any test failures—if known;

(vi) Location of casings and if shorted;

(vii) Any in-service ruptures or leaks—including identified causes;

(viii) Data gathered through integrity assessments required under this section;

(ix) Close interval survey (CIS) survey results;

(x) Depth of cover surveys;

(xi) Corrosion protection (CP) rectifier readings;

(xii) CP test point survey readings and locations;

(xiii) AC/DC and foreign structure interference surveys;

(xiv) Pipe coating surveys and cathodic protection surveys.

(xv) Results of examinations of exposed portions of buried pipelines (*i.e.,* pipe and pipe coating condition, see § 195.569);

(xvi) Stress corrosion cracking (SCC) and other cracking (pipe body or weld) excavations and findings, including in-situ non-destructive examinations and analysis results for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipeline;

(xvii) Aerial photography;

(xviii) Location of foreign line crossings;

(xix) Pipe exposures resulting from encroachments;

(xx) Seismicity of the area; and

(xxi) Other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this part.

(2) Consider information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline;

(3) Consider how a potential failure would affect high consequence areas, such as location of a water intake.

(4) Identify spatial relationships among anomalous information (*e.g.,* corrosion coincident with foreign line crossings; evidence of pipeline damage where aerial photography shows evidence of encroachment). Storing the information in a geographic information system (GIS), alone, is not sufficient. An operator must analyze for interrelationships among the data.

(h) * * *

(1) *General requirements.* An operator must take prompt action to address all anomalous conditions in the pipeline that the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with all other applicable requirements in this part in remediating a condition.

* * * * *

(2) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information to determine that a condition exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition and make the determination required, unless the operator can demonstrate that that 180-day is impracticable. If 180-days is impracticable to make a

determination about a condition found during an assessment, the pipeline operator must notify PHMSA and provide an expected date when adequate information will become available.

* * * * *

(4) *Special requirements for scheduling remediation*—(i) *Immediate repair conditions.* An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce the operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formulas in paragraph (h)(4)(i)(B) of this section, if applicable, or when the formulas in paragraph (h)(4)(i)(B) of this section are not applicable by using a pressure reduction determination in accordance with § 195.106 and the appropriate remaining pipe wall thickness, or if all of these are unknown a minimum 20 percent or greater operating pressure reduction must be implemented until the anomaly is repaired. If the formula is not applicable to the type of anomaly or would produce a higher operating pressure, an operator must use an alternative acceptable method to calculate a reduced operating pressure. An operator must treat the following conditions as immediate repair conditions:

(A) Metal loss greater than 80% of nominal wall regardless of dimensions.

(B) A calculation of the remaining strength of the pipe shows a predicted burst pressure less than 1.1 times the maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991) or AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)) (incorporated by reference, see § 195.3).

(C) A dent located anywhere on the pipeline that has any indication of metal loss, cracking or a stress riser.

(D) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter.

(E) Any indication of significant stress corrosion cracking (SCC).

(F) Any indication of selective seam weld corrosion (SSWC)

(G) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(ii) *270-day conditions.* Except for conditions listed in paragraph (h)(4)(i) of this section, an operator must schedule evaluation and remediation of the following within 270 days of discovery of the condition:

(A) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld.

(B) A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).

(C) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.

(D) A calculation of the remaining strength of the pipe at the anomaly shows a safe operating pressure that is less than MOP at that location. Provided the safe operating pressure includes the internal design safety factors in § 195.106 in calculating the pipe anomaly safe operating pressure, suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991)) or AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)) (incorporated by reference, see § 195.3).

(E) An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.

(F) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.

(G) A potential crack indication that when excavated is determined to be a crack.

(H) Corrosion of or along a longitudinal seam weld.

(I) A gouge or groove greater than 12.5% of nominal wall.

(iii) *Other Conditions.* In addition to the conditions listed in paragraphs (h)(4)(i) and (ii) of this section, an operator must evaluate any condition identified by an integrity assessment or information analysis that could impair the integrity of the pipeline, and as appropriate, schedule the condition for remediation. Appendix C of this part contains guidance concerning other conditions that an operator should evaluate.

(i) * * *

(2) * * *

(ix) Seismicity of the area.

* * * * *

(j) * * * (1) *General.* After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area.

(2) *Verifying covered segments.* An operator must verify the risk factors used in identifying pipeline segments that could affect a high consequence area on at least an annual basis not to exceed 15-months (Appendix C provides additional guidance on factors that can influence whether a pipeline segment could affect a high consequence area). If a change in circumstance indicates that the prior consideration of a risk factor is no longer valid or that new risk factors should be considered, an operator must perform a new integrity analysis and evaluation to establish the endpoints of any previously-identified covered segments. The integrity analysis and evaluation must include consideration of the results of any baseline and periodic integrity assessments (*see* paragraphs (b), (c), (d), and (e) of this section), information analyses (*see* paragraph (g) of this section), and decisions about remediation and preventive and mitigative actions (*see* paragraphs (h) and (i) of this section). An operator must complete the first annual verification under this paragraph no later than [date one year after effective date of the final rule].

* * * * *

(n) *Accommodation of internal inspection devices*—(1) *Scope.* This paragraph does not apply to any pipeline facilities listed in § 195.120(b).

(2) *General.* An operator must ensure that each pipeline is modified to accommodate the passage of an instrumented internal inspection device by [date 20 years from effective date of the final rule].

(3) *Newly-identified areas.* If a pipeline could affect a newly-identified high consequence area (*see* paragraph (d)(3) of this section) after [date 20 years from effective date of the final rule], an operator must modify the pipeline to accommodate the passage of an instrumented internal inspection device within five years of the date of identification or before performing the baseline assessment, whichever is sooner.

(4) *Lack of accommodation.* An operator may file a petition under § 190.9 of this chapter for a finding that

the basic construction (*i.e.* length, diameter, operating pressure, or location) of a pipeline cannot be modified to accommodate the passage of an internal inspection device.

(5) *Emergencies.* An operator may file a petition under § 190.9 of this chapter for a finding that a pipeline cannot be modified to accommodate the passage of an instrumented internal inspection device as a result of an emergency. Such a petition must be filed within 30 days after discovering the emergency. If the petition is denied, the operator must modify the pipeline to allow the passage of an instrumented internal inspection device within one year after the date of the notice of the denial.

Issued in Washington, DC on October 1, 2015, under authority delegated in 49 CFR Part 1.97(a).

Linda Daugherty,

Deputy Associate Administrator for Field Operations.

[FR Doc. 2015–25359 Filed 10–9–15; 8:45 am]

BILLING CODE 4910–60–P