BILLING CODE: 4910-60-W

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA-2010-0229; Amdt. No. 195-102]

RIN 2137-AE66

Pipeline Safety: Safety of Hazardous Liquid Pipelines

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

ACTION: Final rule.

SUMMARY: In response to congressional mandates, NTSB and GAO recommendations, lessons learned, and public input, PHMSA is amending the Pipeline Safety Regulations in an effort to improve the safety of pipelines transporting hazardous liquids. Specifically, PHMSA is extending reporting requirements to certain hazardous liquid gravity and rural gathering lines; requiring inspection of pipelines in areas affected by extreme weather, natural disasters, and other similar events; requiring integrity assessments at least once every 10 years of onshore, piggable, transmission hazardous liquid pipeline segments located outside of high consequence areas (HCAs); incorporating additional conservatism into the existing repair criteria and establishing an adjusted repair schedule to provide greater flexibility; extending the required the use of leak detection systems beyond HCAs to all regulated, non-gathering hazardous liquid pipelines; and requiring all pipelines in or affecting HCAs be capable of accommodating in-line inspection tools within 20 years, unless the basic construction of a pipeline cannot be modified to permit that accommodation. Additionally, PHMSA is clarifying other regulations and is

Version Sent to Federal Register

incorporating Sections 14 and 25 of the PIPES Act of 2016 to improve regulatory certainty and compliance.

DATES: The effective date of these amendments is **[Insert date 6 months after publication in the Federal Register].**

FOR FURTHER INFORMATION CONTACT:

Technical questions: Steve Nanney, Project Manager, by telephone at 713-272-2855 or by electronic mail at steve.nanney@dot.gov.

General information: Robert Jagger, Technical Writer, by telephone at 202-366-4361 or by electronic mail at robert.jagger@dot.gov.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of the Regulatory Action

B. Summary of the Major Provisions of the Regulatory Action In Question

C. Costs and Benefits

II. Background

A. Detailed Overview

B. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

C. National Transportation Safety Board Recommendations

D. Summary of Each Topic Under Consideration

Version Sent to Federal Register

III. Pipeline Advisory Committee

IV. Analysis of Comments and PHMSA Response

A. Reporting requirements for gravity lines

B. Reporting requirements for gathering lines

C. Inspections of pipelines following extreme weather events

D. Periodic assessments of pipelines not subject to integrity management (IM)

E. Repair criteria

F. Expanded use of leak detection systems

G. Increased use of in-line inspection tools

H. Clarifying other requirements

V. PIPES Act of 2016

VI. Section-by-Section Analysis

VII. Regulatory Notices

Version Sent to Federal Register

I. Executive Summary

A. Purpose of the Regulatory Action

In recent years, there have been significant hazardous liquid pipeline accidents, most notably the 2010 crude oil spill near Marshall, MI, during which at least 843,000 gallons of crude oil were released, significantly affecting the Kalamazoo River. In response to accident investigation findings, incident report data and trends, and stakeholder input, the Pipeline and Hazardous Materials Safety Administration (PHMSA) is amending the hazardous liquid pipeline safety regulations 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 pipeline integrity threats, and mitigating the adverse effects of pipeline failures. On October 18, 2010, PHMSA published an Advanced Notice of Proposed Rulemaking (ANPRM) in the Federal Register (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 various pipeline safety issues.

Subsequently, Congress enacted the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (Public Law 112-90) (The Act). That legislation included several provisions that are relevant to the regulation of hazardous liquid pipelines. The Act included mandates for PHMSA to complete studies on topics including existing Federal and State regulations for gathering lines, on automatic shutdown and remote control valves, expanding integrity management requirements beyond high-consequence areas, and on the leak detection systems used by hazardous liquid operators. PHMSA completed these studies and submitted the valve and leak detection studies to Congress on December 27, 2012; the gathering line study to Congress on May 8, 2015; and the integrity management study in April of 2016. These studies are available in the docket for this rulemaking.

Shortly after the Act was passed, the NTSB issued its accident investigation report on the Marshall, MI, accident on July 10, 2012. In it, the NTSB made recommendations regarding the need to revise and update hazardous liquid pipeline regulations. Specifically, the NTSB issued recommendations P-12-03 and P-12-04, which addressed detection of pipeline cracks and "discovery of condition," respectively. The "discovery of condition" recommendation would require, in cases where a determination about pipeline threats has not been obtained within 180

Version Sent to Federal Register

days following the date of inspection, that pipeline operators notify PHMSA 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."

On October 13, 2015, PHMSA published an NPRM to seek public comments on proposed changes to the hazardous liquid pipeline safety regulations (80 FR 61609). A summary of those proposed changes is provided below.

Between the publication of the NPRM and this final rule, the President signed the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016" (PIPES Act), Public Law No. 114-183, on June 22, 2016. While the PIPES Act contained several mandates that must be addressed through rulemaking, a couple of the Act's provisions are self-executing standards that can be incorporated into this rulemaking without a prior notice of proposed rulemaking and opportunity to comment. Those changes are outlined in Section V of this rulemaking.

B. Summary of the Major Provisions of the Regulatory Action

Version Sent to Federal Register

In response to these mandates, recommendations, lessons learned, and public input, PHMSA is making certain amendments to the Pipeline Safety Regulations affecting hazardous liquid pipelines. The first and second amendments extend reporting requirements to certain hazardous liquid gravity and rural gathering lines not currently regulated by PHMSA. The collection of information about these lines, including those that are not currently regulated, 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 and the scope of their applicability are adequate.

The third amendment requires inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events. This provision affects all covered lines under § 195.1, whether they be onshore or offshore, and in an HCA or outside an HCA. Such inspections will help to ensure that operators can safely operate pipelines after these events.

The fourth amendment requires integrity assessments at least once every 10 years, using inline inspection tools or other technology, as appropriate for the threat being assessed, of onshore, piggable, transmission hazardous liquid pipeline segments located outside of high consequence areas (HCAs). Existing regulations require operators to assess hazardous liquid pipeline segments located inside HCAs at least once every 5 years. These assessments will provide important information to operators about the condition of these pipelines, including the existence of internal and external corrosion and deformation anomalies.

The fifth amendment modifies the provisions for determining the need to make pipeline repairs. PHMSA is incorporating additional conservatism into the existing repair criteria for immediate anomalies in HCAs and establishing an adjusted repair schedule to provide greater

Version Sent to Federal Register

flexibility. The paragraph regarding “Engineering Critical Assessments” applies to all onshore pipelines subject to IM.

The sixth amendment extends the required use of leak detection systems beyond HCAs to all regulated transmission hazardous liquid pipelines. The use of such systems will help to mitigate the effects of hazardous liquid pipeline failures that occur outside of HCAs.

The seventh amendment requires that all pipelines in or affecting HCAs be capable of accommodating in-line inspection tools within 20 years, unless the basic construction of a pipeline cannot be modified to permit that accommodation. In-line 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, PHMSA is clarifying other regulations and is incorporating Sections 14 and 25 of the PIPES Act of 2016 to improve regulatory certainty and compliance.

C. Cost and Benefits

Consistent with Executive Orders 12866 and 13563, PHMSA has prepared an assessment of the benefits and costs of the rule as well as reasonably feasible alternatives. PHMSA estimates that up to 471 hazardous liquid operators may incur costs to comply with the proposed rule. The estimated annual costs for individual requirements range between approximately $5,000 and $9.5 million, with aggregate costs of approximately $17.6 million for all requirements. These wide ranges exist because the requirements vary in scope, in addition to compliance cost. For example, some requirements apply only to pipelines within HCAs, others only to those outside HCAs, or some to both; other requirements apply only to onshore pipelines, while others to both

Version sent to Federal Register

onshore and offshore. Accordingly, the length of pipeline, and the number of operators affected both vary for the different requirements.

This rule is primarily designed to mitigate or prevent hazardous liquid pipeline incidents. The rule's information reporting requirements are designed to provide PHMSA information to inform regulatory decision-making. The benefits of prevention include avoided injuries and fatalities, cleanup and response costs, property damage, product loss, and ecosystem impacts. PHMSA is publishing the Regulatory Impact Analysis (RIA) for this rule simultaneously with this final rule, and it is available in the docket. The table below provides a summary of the estimated costs and benefits for each of the eight major provisions and in total (see the RIA for the details of these estimates).

Annualized costs and benefits by requirement area, discounted using 3 percent and 7 percent discount rates (2015$).

Final Rule Requirement Area	3% discount rate		7% discount rate	
	Costs[1]	Benefits	Costs[1]	Benefits
1. Reporting requirements for gravity lines.	$5,000	Better risk understanding and management.[2]	$5,000	Better risk understanding and management.[2]
2. Reporting requirements for gathering lines.	$74,000	Better risk understanding and management.[3]	$74,000	Better risk understanding and management.[3]
3. Inspections of pipelines in areas affected by extreme weather events.	$0	$0	$0	$0
4. Assessments of pipelines that are not already covered under the IM program every 10 years.[4, 5]	$2,966,000	Avoided incidents and damages through detection of safety conditions.[6]	$2,966,000	Avoided incidents and damages through detection of safety conditions.[6]
5. IM repair criteria.	$0	$0	$0	$0
6. LDSs on pipelines located in non-HCAs. [5]	$8,373,700	Reduced damages through earlier detection and response.[7]	$9,546,600	Reduced damages through earlier detection and response.[7]
7. Increased use of ILI tools.	$0	$0	$0	$0

Version Sent to Federal Register

Final Rule Requirement Area	3% discount rate		7% discount rate	
	Costs[1]	Benefits	Costs[1]	Benefits
8. Clarify certain IM plan requirements.	$4,946,000	Reduced damages through prevention and earlier detection and response.[8].	$5,032,000	Reduced damages through prevention and earlier detection and response.[8]
Total	**$16,364,700**	**Reduced damages from avoiding and/or mitigating hazardous liquid releases**	**$17,623,600**	**Reduced damages from avoiding and/or mitigating hazardous liquid releases**

1. Costs in this table are rounded to the nearest thousand dollars and may differ from costs presented in individual sections of the document.

2. Gravity lines can present safety and environmental risks. Depending on the elevation change, a gravity flow pipeline could have more pressure than a pipeline with pump stations to boost the pressure. The benefits of this requirement are not quantified, but based on social costs of $42 per gallon for releases from regulated gathering lines (see Section 2.6.2), the information would need to lead to measures preventing the release of 120 gallons per year to generate benefits that equal the costs.

3. The benefits are not quantified, but based on social costs of $42 per gallon for releases from regulated gathering lines (see Section 2.6.2), the information would need to lead to measures preventing the release of 1,770 gallons per year to generate benefits that equal the costs.

4. PHMSA also conducted a sensitivity analysis that uses alternative baseline assumptions for pipelines not currently covered under the IM program. Specifically, PHMSA estimated the costs for two alternative scenarios: 1) a scenario that assumes that 100 percent of non-HCA mileage is assessed in the baseline; and 2) a scenario that assumes that 83 percent of the mileage is assessed in the baseline. Costs for these two scenarios are $0 and $5.9 million, respectively. See Section 3.4.3 for details.

5. The requirement is not applicable to gathering lines.

6. Given annual costs of $3.0 million and a cost per incident of $553,200, incremental assessment of pipelines outside of HCAs would need to prevent 5 incidents for benefits to equate costs. See Section 3.4.3 for details.

7. As discussed in Section 2.6.2, 1,396 incidents involved non-HCA pipelines between 2010 and 2015, or an average of 233 incidents per year. The vast majority of these incidents (1,344 incidents in total or 224 per year, on average) do not involve gathering lines. Costs associated with incidents outside of HCAs (excluding gathering lines) average approximately $398,400 per incident, not including additional damages and costs that are excluded or underreported in the incident data.

8. The benefits of reduced costs associated with the prevention or reduction of released hazardous liquids cannot be quantified but could vary in frequency and size depending on the types of failures that are averted. Including additional pipelines in the IM plan, integrating data, and conducting spatial analyses is expected to enhance an operator's ability to identify and address risk. The societal costs associated with incidents involving pipelines in HCAs average $1.9 million per incident (see Section 2.6.2). The annual cost estimates for this requirement are equivalent to the average damages from fewer than three such incidents. This is relative to an annual average of 158 incidents in HCAs between 2010 and 2015.

Version sent to Federal Register

II. Background

A. Detailed Overview

Introduction

The significant and expected growth in the nation's production and use of oil is placing unprecedented demands on the nation's pipeline system, underscoring the importance of moving this energy product safely and efficiently. With changing spatial patterns of oil production and use and an aging pipeline network, improved data collection and systemic risk management are increasingly necessary for the industry to make reasoned safety choices and for preserving public confidence in its ability to do so. Congress recognized these needs when passing the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, calling for an examination of a broad range of issues pertaining to the safety of the nation's pipeline network, including a requirement for PHMSA to evaluate whether integrity management system requirements, or elements thereof, should be expanded beyond HCAs, and issue regulations if supported by the findings of that evaluation.

This final rule addresses the requirements established by Congress in the 2011 Act, which are consistent with the emerging needs of the nation's hazardous liquid pipeline system. This final rule also advances an important discussion about the need to adapt and expand risk-based safety practices in light of changing markets and a growing national population whose location choices are located in ever-closer proximity to existing pipelines.

This rule strengthens protocols for IM, including protocols for inspections and repairs, and improves and streamlines information collection to help drive risk-based identification of the areas with the greatest safety deficiencies. While PHMSA believes operators would comply with this rule's integrity management and repair criteria requirements in the absence of this rule, these changes will ensure prompt identification and remediation of potentially hazardous defects and anomalies to the extent any operators would not take such actions in the absence of the rule,

Version Sent to Federal Register

while still allowing operators to make risk-based decisions on where to allocate their maintenance and repair resources.

Hazardous Liquid Infrastructure Overview

Pipelines are the primary method for transporting crude oil in the United States. In 2015, operators reported to PHMSA a total of 207,806 miles[1] of hazardous liquid transmission pipelines in the United States, and it is estimated that there are 30,000 to 40,000 miles[2] of crude oil gathering lines located primarily in oil-producing states. There are two major types of pipelines along the petroleum transportation route: gathering pipeline systems, and crude oil and refined products transmission pipeline systems.

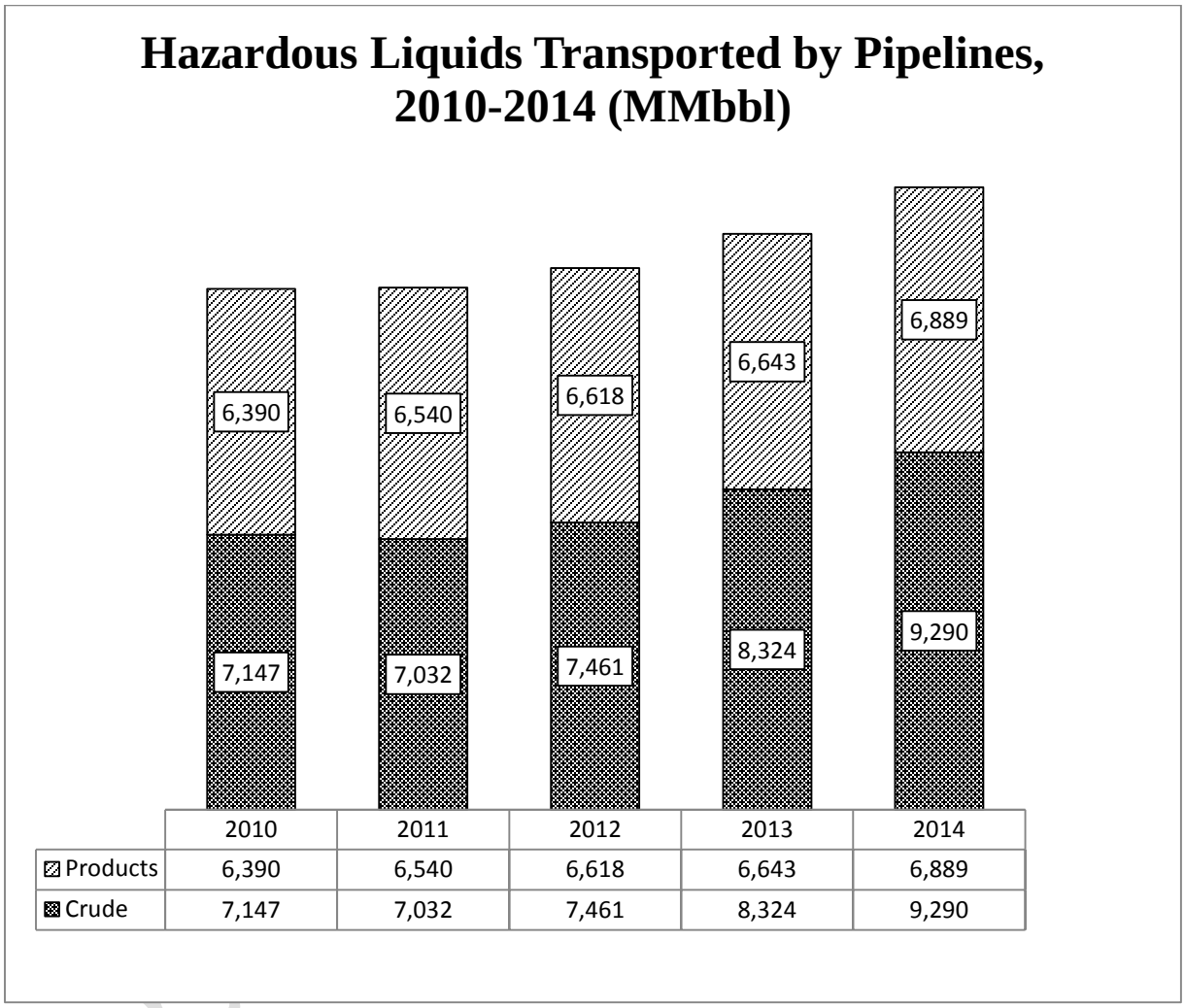
Gathering lines are typically smaller pipelines no more than 8 5/8 inches in diameter that transport petroleum from onshore and offshore production facilities. Hazardous liquid transmission pipelines transport the crude oil from the gathering systems to refineries and from refineries to distribution centers. Hazardous liquid transmission lines transport both crude and refined products, and can be tens to hundreds of miles long. These lines may cross State and continental borders, and range in size from 2 to 48 inches in diameter. Hazardous liquid transmission pipeline networks also include pump stations, which move the oil along the pipelines, and storage terminals. Changes in product demand has also led to efforts by operators to increase pipeline capacity through flow direction reversals or converting natural gas pipelines

[1] PHMSA's Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems; http://phmsa.dot.gov/pipeline/library/data-stats/annual-report-mileage-for-hazardous-liquid-or-carbon-dioxide-systems

[2] GAO-12-388 "Pipeline Safety: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety," March 2012, pg. 3; http://www.gao.gov/assets/590/589514.pdf

Version Sent to Federal Register

into oil pipelines. Transmission pipelines in the United States moved an estimated 14 billion barrels of crude and refined oil products in 2012. The location, construction and operation of these systems are generally regulated by Federal and State requirements.



Hazardous Liquids Transported by Pipelines, 2010-2014 (MMbbl)			
Year	**Crude**	**Products**	**Total**
2010	7,147	6,390	13,538
2011	7,032	6,540	13,572

2012	7,461	6,618	14,079
2013	8,324	6,643	14,967
2014	9,290	6,889	16,179
AOPL Compilation of FERC Form 6 Data			

MMbbl = Million Barrels, 1 Barrel = 42 gallons

According to PHMSA's database, 48.1 percent of all hazardous liquid lines were installed prior to 1970.[3] However, pipeline manufacturing, construction, and operational and maintenance practices have been improving steadily in recent decades, and some older pipes are susceptible to certain manufacturing or construction defects. For example, low-frequency electric resistance welded (ERW) pipe used from the early 1900s through the post-World War II construction boom that lasted well into the 1960s is vulnerable to seam-quality issues. Since the early 1970s, many improvements in pipe manufacturing and materials have been made, and steel and seam properties of pipe have improved with the increased use of high-frequency ERW, submerged arc welded, and seamless pipe. In addition, pigs and crawlers for conducting in-line inspections for erosion and corrosion in buried pipes were not developed until the 1960s and 1970s prior to the adoption of the part 195 regulations.

Since 2008, U.S. oil production has increased more than 40 percent, resulting in the United States becoming the world's largest producer of liquid fuels in early 2014. The new tight

[3] PHMSA's "Pipeline Replacement Updates: By-Decade Inventory," http://opsweb.phmsa.dot.gov/pipeline_replacement/by_decade_installation.asp

Version Sent to Federal Register

oil plays in Texas and North Dakota now account for about half of the U.S. production, balancing declining production in older plays.

While tight oil from shale plays has historically been more difficult to extract, improvements in drilling and production methods, such as horizontal drilling and hydraulic fracturing, have made it economically recoverable. This has reduced U.S. refiners' dependence on imported crudes, and U.S. crude oil imports from outside the Northern Hemisphere have dropped to less than 40 percent of total crude imports. These supply increases and spatial changes in production patterns are creating wide-ranging impacts on liquid fuels transportation infrastructure.

Regulatory History

Congress established the current framework for regulating the safety of hazardous liquid pipelines in the Hazardous Liquid Pipeline Safety Act (HLPSA) of 1979 (Public Law 96-129). Like its predecessor, the Natural Gas Pipeline Safety Act (NGPSA) of 1968 (Public Law 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 the U.S. 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).

Version Sent to Federal Register

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. A combination of prescriptive and performance-based safety standards are used (i.e., a particular objective is specified, but the method of achieving that objective is not). Risk management principles play a key role in the IM requirements.

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. 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.

Public utility commissions administer most State pipeline safety programs. These State authorities must adopt the Pipeline Safety Regulations as part of a certification or agreement with PHMSA, but may establish more stringent safety standards for intrastate pipeline facilities within their State regulatory authorities. PHMSA is precluded from regulating the safety standards or practices for an intrastate pipeline facility if a State is currently certified to regulate that facility.

In 2000 and 2002, the Office of Pipeline Safety (OPS) published regulations requiring IM programs for hazardous liquid pipeline operators in response to a hazardous liquid incident in Bellingham, WA, in 1999 that killed three people.[4] The regulations were broad-reaching and

[4]65 FR 75378 Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipeline); 67 FR 1650 Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Repair Criteria); 67 FR 2136 Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With Less Than 500 Miles of Pipelines)

Version Sent to Federal Register

supplemented PHMSA's prescriptive safety requirements with performance and process-oriented requirements. The approach aimed to set expectations for operators while giving them a degree of flexibility in how they complied with those expectations. The objectives of the IM regulations were to accelerate and improve the quality of integrity assessments conducted on pipelines in areas with the highest potential for adverse consequences; promote a more rigorous, integrated, and systematic management of pipeline integrity and risk by operators; strengthen the government's role in the oversight of pipeline operator integrity plans and programs; and increase the public's confidence in the safe operation of the nation's pipeline network.

In January 2011, PHMSA published the Hazardous Liquid Integrity Management Progress Report, which reported on PHMSA's progress in achieving the program objectives and examined accident trends. The report found that the IM rule and PHMSA's rigorous oversight of operator compliance with the rule are contributing to improved safety performance, including a reduction in the frequency of significant accidents and a decrease in volume spilled in significant accidents.

PHMSA's Progress on Integrity Management

The original part 195 Pipeline Safety Regulations were not designed with risk-based regulations in mind. In the mid-1990s, following models from other industries such as nuclear power, PHMSA started to explore whether a risk-based approach to regulation could improve safety of the public and the environment. During this time, PHMSA found that many operators were performing forms of IM that varied in scope and sophistication but that there were no minimum standards or requirements.

Version sent to Federal Register

Since the implementation of the IM regulations more than 10 years ago, many factors have changed. Most importantly, there have been sweeping changes in the oil industry, and the nation's relatively safe but aging pipeline network faces increased pressures from these changes. Long-identified pipeline safety issues, some of which IM set out to address, remain problems. Infrequent but severe accidents indicate that some pipelines continue to be vulnerable to failures stemming from, among other things, outdated construction methods or materials. Some severe pipeline accidents have occurred in areas outside HCAs where the application of IM principles is not required.

The current IM program is both a set of regulations and an overall regulatory approach to improve pipeline operators' ability to identify and mitigate the risks to their pipeline systems. On the operator level, an IM program consists of multiple components, including adopting procedures and processes to identify high consequence areas (HCAs), which are areas with the greatest population density and environmental sensitivity; determining likely threats to the pipeline within the HCA; evaluating the physical integrity of the pipe within the HCA; and repairing or remediating any pipeline defects found. Because these procedures and processes are complex and interconnected, effective implementation of an IM program relies on continual evaluation and data integration.

Operators have made great progress towards achieving the IM objectives. Operators have an improved understanding of the precise locations of their HCAs – those areas where integrity assessments and other protective measures spelled out in the IM rule must be taken to assure public safety and environmental protection. Petroleum can spread over large areas and cause environmental damage. The IM protections for HCAs are designed to account for the potential

Version Sent to Federal Register

environmental and community risks from oil releases. According to PHMSA's Hazardous Liquid annual data, 41 percent of the nation's hazardous liquid pipelines[5] can potentially affect HCAs and thus receive the enhanced level of integrity assessment and protection mandated by the IM rule. As required by the IM rule, operators have also conducted baseline integrity assessments on all pipelines that could affect HCAs and have begun conducting reassessments of these same pipeline segments. Operators now have an improved understanding of the condition of pipelines in these safety-sensitive areas.

According to PHMSA's January 2011 Hazardous Liquid Integrity Management Progress Report, [6] which tracked the progress and effectiveness of the IM program in its first decade, as a result of these initial baseline assessments, operators have made more than 7,600 repairs of anomalies that required immediate attention, remediated over 28,000 other conditions on a scheduled basis, and addressed an additional 79,000 anomalies that were not required to be addressed by the IM rule, thus significantly improving the condition of the nation's pipelines. The programmatic and process-oriented requirements of the rule have fostered a more systematic, risk-based approach to managing integrity. Operators are generally making progress toward developing proactive IM programs.

However, based on recent accidents and mandates from the 2011 Pipeline Safety Act, improvement is still needed in the areas of data integration, consideration of interactive

---

5 http://phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=a872dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print

6 http://primis.phmsa.dot.gov/iim/IM_Jan2011_StatusReport_01_23_11.pdf

Version Sent to Federal Register

anomalies, risk modelling, risk analysis, and the use of this analysis to identify and implement additional preventive and mitigative measures to reduce risk. These aspects of the rule are critical, as the integrity assessment provisions of the rule only address some of the causes of pipeline failures. The rule's preventive and mitigative requirements address the risks that operators identify and reduce the consequences of a failure.

Inadequate Leak Detection, Exposure to Weather, Increased Use, and Age Can Increase the Risk of Pipeline Incidents

Risk factors for pipeline safety issues stem from many sources, including manufacturing issues, external weather and environmental factors, increased use, activity near the pipeline, other operational issues, and age-related integrity issues.

On July 25, 2010, a segment of a 30-inch-diameter pipeline, owned and operated by Enbridge Incorporated, ruptured in a wetland in Marshall, MI. According to the NTSB's Pipeline Accident Report on the incident, the rupture occurred during the last stages of a planned shutdown and was not discovered or addressed for over 17 hours. During the time lapse, Enbridge twice pumped additional oil (81 percent of the total release) into Line 6B during two startups; the total release was estimated by Enbridge to be 843,444 gallons of crude oil. [7] The oil saturated the surrounding wetlands and flowed into the Talmadge Creek and the Kalamazoo River. This incident motivated a reexamination of hazardous liquid pipeline safety. The NTSB made recommendations to PHMSA and industry regarding the need to improve hazardous liquid

[7] National Transportation Safety Board: "Enbridge Incorporated Hazardous Liquid Pipeline Rupture and Release, Marshall, Michigan, July 25, 2010," Accident Report NTSB/PAR-12/01, adopted 2012; http://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1201.pdf

Version Sent to Federal Register

pipeline safety. Congress also directed PHMSA to reexamine many of its safety requirements, including the expansion of IM regulations for transmission pipelines. Other recent accidents, including a pair of related failures that occurred in 2010 on a crude oil pipeline in Salt Lake City, UT, corroborated the significance of having an adequate means for identifying leaks in all locations.

The nation's pipeline system also faces significant risk from failure due to extreme weather events such as hurricanes, floods, mudslides, tornadoes, and earthquakes. On January 17, 2015, a breach in the Bridger Pipeline Company's Poplar system resulted in a spill into the Yellowstone River near the town of Glendive, MT, releasing 31,835 gallons (758 barrels)[8] of crude oil into the river and affecting local water supplies. Preliminary information indicates over 100 feet of pipeline was exposed on the river bottom, and the release point was near a girth weld. While a depth of cover survey indicated sufficient cover in late 2011, [9] PHMSA understands the area experienced localized flooding in early 2014. A previous crude oil spill into the Yellowstone River in 2011 near Laurel, MT, was caused by channel migration and river bottom scour, leaving a large span of the pipeline exposed to prolonged current forces and debris washing downstream in the river. Those external forces damaged the exposed pipeline.

[8] PHMSA Database: "Operator Information: Incident and Mileage Data: Bridger Pipeline LLC," http://primis.phmsa.dot.gov/comm/reports/operator/OperatorIM_opid_31878.html?nocache=4851%20-%20_Incidents_tab_3#_OuterPanel_tab_2

[9] PHMSA, Corrective Action Order, CPF No. 5-2015-5003H, page 4, January 23, 2015; http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Pipeline/520155003H_Corrective%20Action%20Order_01232015.pdf

Version Sent to Federal Register

Previously, in October 1994, flooding along the San Jacinto River led to the failure of eight hazardous liquid pipelines and undermined a number of other pipelines. The escaping products were ignited, leading to 547 people in the area suffering extensive smoke inhalation or burn injuries.[10] According to PHMSA's Accident and Incident Data for hazardous liquid pipelines, from 2003 to 2013, there were 85 reportable incidents in which storms or other severe natural force conditions damaged pipelines and resulted in their failure. Operators reported total damages of over $104 million from these incidents.[11] PHMSA has issued several Advisory Bulletins to operators warning about extreme weather events and the consequences of flooding events, including river scour and river channel migration.

In addition to external weather and environmental threats, changing production and shipment patterns are increasing stress on the nation's pipeline system. Shifting production to tight oil production like shale plays have changed U.S. oil production locations, as well as the types of crude transported in the nation's pipelines. The U.S. pipeline system has previously moved crude oil from interior production regions to the Gulf of Mexico refineries, and petroleum products from Gulf Coast refineries to the interior of the country. However, increased tight oil

Version Sent to Federal Register

[10] NTSB, Pipeline Special Investigation Report, "Evaluation of Pipeline Failures During Flooding And Of Spill Response Actions, San Jacinto River Near Houston, Texas, October 1994;" NTSB/SIR-96/04, Adopted September 6, 1996;
http://pstrust.org/docs/ntsb_doc24.pdf

[11] PHMSA Database: "Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data;" http://phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=fdd2dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print

production requires significant infrastructure expansion in new areas, and shifting production areas are changing the patterns of oil transport from shale plays out to coastal refineries. Because new pipelines require long-term shipping commitments for investments, the industry has initially adapted to these shifts by increasing rail shipments of oil. Between 2011 and 2014, interstate crude oil pipeline capacity from North Dakota doubled.[12] The Dakota Access pipeline, currently under construction, will add a further 450,000 bpd of capacity.[13] Many operators are adapting their systems to move crude oil to markets formerly dependent on imports by modifying existing pipelines. These modifications can be made by reversing flow directions and repurposing natural gas pipelines; pipeline expansion projects can also increase pumping capability with minimal alterations of the pipeline itself.

Reversing a pipeline's flow can cause added stresses on the system due to changes in pressure gradients, flow rates, and product velocity, which can create new risks of internal corrosion. Occasional failures on hazardous liquid pipelines have occurred after operational changes that include flow reversals and product changes. PHMSA has noticed a large number of recent or proposed flow reversals and product changes on a number of hazardous liquid and gas transmission lines. In response to this phenomenon, on September 18, 2014, PHMSA issued an

[12] North Dakota State Pipeline Authority: US Williston Basin Crude Oil Export Options, July 14, 2016. https://ndpipelines.files.wordpress.com/2012/04/williston-basin-crude-export-options-7-14-2016.jpg

[13] Energy Transfer Partners, Dakota Access Pipeline Fact Sheet

Version Sent to Federal Register

Advisory Bulletin[14] notifying operators of the potentially significant impacts such changes may have on the integrity of a pipeline.

Data indicate that some pipelines also continue to be vulnerable to issues stemming from outdated construction methods or materials. Much of the older line pipe in the nation's pipeline infrastructure was made before the 1970s using techniques that have proven to contain latent defects due to the manufacturing process. Such defects cause the pipe to be susceptible to developing hook cracks or other anomalies that may, over time, lead to failures if they are not timely repaired. For example, line pipe manufactured using low frequency electric resistance welding is susceptible to seam failure. A substantial amount of this type of pipe is still in service; according to PHMSA's "Miles by Decade of Installation Inventory Reports"[15] for hazardous liquid lines, there were 100,008 miles of pre-1970s pipe still in service in 2015. The IM regulations include specific requirements for evaluating such pipe if located in HCAs, but infrequent-yet-severe failures that are attributed to longitudinal seam defects continue to occur. According to PHMSA's Accident and Incident database, between 2010 and 2014, 15 reportable incidents were attributed to seam failures, resulting in over $8 million of property damage.[16] Although some of these anomalies can present a significant threat to the integrity of a hazardous liquid pipeline, current repair criteria have not been adequate to ensure safety.

Version Sent to Federal Register

[14] PHMSA: "Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes and Conversion to Service" *Advisory Bulletin*, 79 FR 56121, September 18, 2014; http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Advisory%20Notices/ADB-2014-04_Flow_Reversal.pdf

[15] https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages

[16] http://phmsa.dot.gov/pipeline/library/data-stats/pipelineincidenttrends

In the final rule, PHMSA strengthens the IM requirements to identify and respond to the increased pipeline risks resulting from leaks, weather, and increased use and age of a pipe, as well as allowing operators to remediate pipeline anomalies while allocating resources to areas that present a higher risk of harm.

Enhanced Collection of Data

In order to keep the public safe and to protect the nation's energy security and reliability, operators and regulators must have an intimate understanding of their entire pipeline system, including threats and operations. However, due to an increase in unregulated gathering lines along with aging lines that are not modernized for internal inspection, there continue to be data gaps that make it hard to fully understand the risks to the integrity of the nation's pipeline system.

The rise of shale oil production is altering not just the extent, but also the characteristics of the nation's oil gathering systems. Oil wells are being developed in new geographic areas, thus requiring entirely new gathering systems and expanded networks of gathering lines. Most of these new gathering lines are unregulated, and PHMSA does not collect incident data or report annual data on these unregulated lines. The dramatic expansion in oil production and changes in typical gathering line characteristics require PHMSA to review its regulatory approach to gathering pipelines to address new safety and environmental risks.

PHMSA's regulations also exempt gravity lines. These pipelines carry product by means of gravity, and 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 high pressures. PHMSA is aware of gravity lines that traverse long distances with significant elevation changes, which

Version Sent to Federal Register

could have significant consequences in the event of a release. Both gravity and gathering lines are currently excluded from reporting requirements, leaving large gaps in PHMSA's knowledge of these unregulated pipeline systems.

Data gathering and integration are important elements of good IM practices, and while many strides have been made over the years to collect more and better data, several data gaps still exist. Much of operators' and PHMSA's data is obtained through testing and inspection under IM requirements.

To assess a pipeline's integrity, operators generally choose between three methods of testing a pipeline: in-line inspection (ILI), pressure testing, and direct assessment (DA). In 2015, we estimate that slightly over 90 percent of the hazardous liquid line mileage in HCAs is already "piggable" (have launchers and receivers for in-line inspection devices), and almost 90 percent of these lines were inspected with ILI.

Operators perform ILIs by using special tools, sometimes referred to as "smart pigs," which are usually pushed through a pipeline by the pressure of the product being transported. As the tool travels through the pipeline, it identifies and records potential pipe defects or anomalies. Because these tests can be performed with product in the pipeline, the pipeline does not have to be taken out of service for testing to occur, which can reduce cost to the operator and possible service disruptions to consumers. Further, ILI is a non-destructive testing technique, and it can be less costly on a per-unit basis to perform than other assessment methods. However, a very small portion of hazardous liquid pipe segments cannot be inspected through ILI because they are too short, which makes getting accurate ILI tool results impractical due to tool speed

Version Sent to Federal Register

variations. Other hazardous liquid pipelines might not be inspected through ILI because they do not have enough operating pressure to run the tool.

Pipeline operators typically use pressure tests as a means to determine the integrity (or strength) of the pipeline immediately after construction and before placing the pipeline in service, as well as periodically during a pipeline's operating life. In a pressure test, a test medium (typically water) inside the pipeline is pressurized to a level greater than the normal operating pressure of the pipeline. This test pressure is held for a number of hours to ensure there are no leaks in the pipeline.

Direct assessment (DA) is the evaluation of various locations on a pipeline for corrosion threats. Operators will review records, indirectly inspect the pipeline, or use mathematical models and environmental surveys to find likely locations on a pipeline where corrosion might be occurring. Operators subsequently excavate and examine areas that are likely to have suffered from corrosion. DA can be costly to use unless targeting specific locations. Specific locations, however, may not give an accurate representation of the condition of lengths of entire pipeline segments.

Ongoing research appears to indicate that ILI and spike hydrostatic pressure testing are more effective than DA for identifying pipe conditions related to stress corrosion cracking (SCC) defects. Hydrostatic testing of hazardous liquid pipelines requires testing to at least 125 percent of the maximum operating pressure (MOP) for at least 4 continuous hours and an additional 4 hours at a pressure of at least 110 percent of MOP if the pipe is not visible. If there is concern with latent cracks that might grow due to a pressure reversal, then a spike test at the maximum pressure of 139 percent of MOP for a short period (up to a 30-minute hold time) may be

Version Sent to Federal Register

conducted. The spike test will serve to clear any cracks that might otherwise grow during pressure reductions after the hydrostatic test or as a result of operational pressure cycles. SCC is the growth of cracks due to a corrosive environment, which can cause pipes to fail due to tensile stresses during normal operation. SCC can be hard to detect and can progress rapidly. Both regulators and operators have expressed interest in improving ILI methods as an alternative to hydrostatic testing for better risk evaluation and management of pipeline safety. Hydrostatic pressure testing can result in substantial costs and occasional disruptions in service. Further, following the incident at Marshall, MI, Enbridge told NTSB investigators that, when the right technology and processes are implemented, ILI has been shown to be more effective than hydrostatic testing at maintaining a reliable pipeline. ILI testing can obtain data along a pipeline not otherwise obtainable via other assessment methods, although this method also has certain limitations.

In this final rule, PHMSA is addressing data gaps and increasing the quality of data collected by expanding the reporting requirements to cover both gathering and gravity lines and requiring that all lines in HCAs be piggable for a better understanding of pipeline characteristics. The final rule will also require operators to fully integrate their pipeline data across all data sources to close any remaining gaps.

Looking at Risk Beyond HCAs

In addition to improving IM programs, PHMSA understands the importance of carefully reconsidering the scope of the areas covered by IM requirements. While PHMSA's hazardous liquid IM program manages risks primarily by focusing oversight on areas with the greatest population density and environmental sensitivity, it is imperative to protect the safety of

Version Sent to Federal Register

environmental resources and communities throughout the country. The changing landscape of production, consumption, and product movement merits a fresh look at the current scope of IM coverage.

The current definition of an HCA uses Census Bureau definitions of urbanized areas or areas with a concentrated population. The HCA definition also encompasses "unusually sensitive areas," including drinking water or ecological resource areas and commercially navigable waterways. However, liquid spills, even outside HCAs, can result in environmental damage necessitating clean up, restoration costs, and lost use and non-use values. If operators do not assess and repair their pipelines, liquid spills are more likely to occur. In fact, devastating incidents have occurred outside of HCAs in rural areas where populations are sparse, and operators have not been required to assess their lines as frequently as lines covered by IM. According to PHMSA's databases, over the 10-year period of 2005-2015, significant incidents at hazardous liquid facilities accounted for over 919,000 barrels spilled, 35 injuries, and 18 fatalities. Out of those, over 766,000 barrels spilled, 22 injuries, and 15 fatalities occurred in non-HCA areas.[17] This data shows that ruptures with the potential to affect populations, the environment, or commerce, can occur anywhere on the nation's pipeline system.

Version Sent to Federal Register

[17] Data compiled from PHMSA's "Significant Incidents" and "Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data": http://opsweb.phmsa.dot.gov/primis_pdm/significant_inc_trend.asp; http://phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=fdd2dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print

If constant improvement and zero incidents are goals for pipeline operators, extending and prioritizing IM assessments and principles to all parts of pipeline networks is an effective way to achieve those goals. Extending IM assessments and principles to non-HCAs is needed to help clarify vulnerabilities and prioritize improvements, and this final rule takes important steps towards developing that approach and will lead operators to gather valuable information they may not have collected if regulations were not in place.

In this final rule, PHMSA is requiring operators to assess onshore, piggable, transmission pipelines outside of HCAs periodically using ILI or other technology, if appropriate, to detect (and later remediate) anomalies in all locations within their pipeline systems. PHMSA is also providing operators with specific deadlines to verify their segment analyses to identify any new HCAs and implement the appropriate actions. These changes would ensure the remediation, commensurate with the severity of the defects, of anomalous conditions that could potentially impact people, property, or the environment, while at the same time allowing operators to allocate their resources to HCAs on a higher-priority basis.

Considering recent incidents and many of the factors outlined above, PHMSA believes IM has led to several improvements in managing pipeline safety, yet the agency believes there is still more to do to improve the safety of hazardous liquid pipelines and better ensure public confidence.

Recent Developments in Hazardous Liquid Pipeline Safety Regulation

On October 18, 2010, PHMSA posed a series of questions to the public in the context of an ANPRM titled “Pipeline Safety: Safety of On-Shore Hazardous Liquid Pipelines” (75 FR 63774). In that document, PHMSA sought comments on several proposed changes to part 195, in

Version Sent to Federal Register

particular: 1) The scope of part 195 and existing regulatory exceptions, 2) Criteria for designation of HCAs, 3) Leak detection and emergency flow restricting devices, 4) Valve spacing, 5) Repair criteria outside of HCAs, and 6) Stress corrosion cracking. The questions in this ANPRM considered topics relating to the statutory mandates; the post-Marshall, MI, NTSB and GAO recommendations; and other pipeline safety mandates. Twenty-one organizations and individuals submitted comments in response to the ANPRM.

PHMSA reviewed the received comments and responded in the subsequent NPRM published on October 13, 2015 (80 FR 61609). In summary, the NPRM addressed the following areas: 1) Reporting requirements for gravity lines, 2) Reporting requirements for gathering lines, 3) Inspections of pipelines following extreme weather events, 4) Periodic assessments of pipelines not subject to IM, 5) Repair criteria, 6) Expanded use of leak detection systems, 7) Increased use of in-line inspection tools, and 8) Clarifying other requirements. A summary of comments and responses to those comments are provided later in the document. The ANPRM and NPRM may be viewed at http://www.regulations.gov by searching for Docket ID PHMSA-2010-0229.

The changes in this final rule will improve the safety and protection of pipeline workers, the public, property, and the environment by improving the detection and remediation of unsafe conditions, better ensuring that certain currently unregulated pipelines are subject to appropriate regulatory oversight, and speeding mitigation of adverse effects of pipeline failures.

B. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

Version Sent to Federal Register

Subsequent to the issuance of the ANPRM on October 18, 2010, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 included several statutory requirements related directly to the topics being considered in the ANPRM. The related topics and statutory citations include, but are not limited to:

- Section 5(f) – Requires regulations issued by the Secretary, if any, to expand integrity management system requirements, or elements thereof, beyond high-consequence areas. These regulations are to be dependent on an evaluation and report of whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas and, with respect to gas transmission pipeline facilities, whether applying integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements;
- Section 8 – Requires regulations regarding leak detection on hazardous liquid pipelines and establishing leak detection standards. These regulations are to be dependent on a report on the analysis of the technical limitations of current leak detection systems, including the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies, and an analysis of the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems;
- Section 14 – Permits PHMSA to issue regulations for pipelines transporting non-petroleum fuels, such as biofuels;

Version Sent to Federal Register

- Section 21 – Requires a review on the regulation of Gas (and Hazardous Liquid) Gathering Lines and the issuance of further regulations, if appropriate; and
- Section 29 – Requires that operators consider seismicity when evaluating pipeline threats.

C. National Transportation Safety Board Recommendations

On July 10, 2012, shortly after the Act was passed, the NTSB issued its accident investigation report on the Marshall, MI, accident. In it, the 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, which addressed detection of pipeline cracks and "discovery of condition," respectively, and are as follows:

- Assessments. NTSB Recommendation P-12-03: *"Revise Title 49 Code of Federal Regulations 195.452 to clearly state (1) when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed; (2) the acceptable methods for performing these engineering assessments, including the assessment of cracks coinciding with corrosion with a safety factor that considers the uncertainties associated with sizing of crack defects; (3) criteria for determining when a probable crack defect in a pipeline segment must be excavated and time limits for completing those excavations; (4) pressure restriction limits for crack defects that are not excavated by the required date; and (5) acceptable methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or stress corrosion cracking as applicable."*

Version Sent to Federal Register

- Discovery of Incidents. NTSB Recommendation P-12-4: *"Revise Title 49 Code of Federal Regulations 195.452(h)(2), the 'discovery of condition,' to 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."*

D. Summary of Each Topic

This final rule amends the Federal pipeline safety regulations to address the following topics. Details of the changes in this rule are discussed below in Section IV, "Analysis of Comments and PHMSA Response," and Section V, "Section-by-Section Analysis."

Extend Certain Reporting Requirements to Certain 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. Further, certain gravity lines may have significant elevation changes, which can lead to serious consequences in the event of a release.

In order for PHMSA to effectively analyze the safety performance and 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 is not affected by any of the provisions in the Pipeline Safety Act of 2011. Accordingly, PHMSA is amending the

Version Sent to Federal Register

Pipeline Safety Regulations (PSR) to require that the operators of certain 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 to the ANPRM from API-AOPL, three operators have approximately 17 miles of gravity-fed pipelines. PHMSA estimated that proportionally five operators would have 28 miles of gravity-fed pipelines.

PHMSA is also amending the PSR to extend the annual, accident, and safety-related condition reporting requirements of part 195 to all hazardous liquid gathering lines. The Hazardous Liquid Pipeline Safety Act of 1979 (Pub. L. 96-129) did not mandate the regulation of rural gathering lines because at that time they were not thought to present a significant enough risk to public safety to justify Federal regulation based on the data available at that time. However, the Pipeline Safety Act of 1992 (Pub. L. 102-508) 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 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.

Version Sent to Federal Register

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 published a final rule on June 3, 2008 (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 MOP 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, in the Pipeline Safety Act of 2011, Congress also ordered the Secretary to review existing State and Federal regulations for hazardous liquid gathering lines and 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. The study, titled "Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Gathering Lines," which was performed by the Oak Ridge National Laboratory and published on May 8, 2015, found "federal regulatory issues that may be a

Version Sent to Federal Register

possible source of confusion and misunderstanding concerning design, construction, operation, and maintenance of natural gas and hazardous liquid gathering lines." PHMSA is currently statutorily limited to regulating gathering lines in HCAs and "regulated rural gathering lines," which are defined in § 195.11 to mean onshore gathering lines in a rural area that meet certain criteria (i.e., has a nominal diameter from 6-5/8 in. (168 mm) to 8-5/8 in. (219.1 mm), is located in or within ¼ mile of an unusually sensitive area as defined in § 195.6, and operates at a maximum pressure established under § 195.406). This limitation leaves potential gaps in the regulation of rural gathering lines not classified as regulated rural gathering lines.

Further, while Congress directed the Secretary to consider, in the study, whether existing Federal regulations should be applied to gathering lines not currently subject to Federal regulation, PHMSA currently collects no data on unregulated gathering lines. This lack of data prevents PHMSA from being able to determine whether current regulations should be applied to currently unregulated gathering lines. Therefore, in this final rule, PHMSA is requiring reporting on all gathering lines and is taking proactive steps and proposing additional regulations to help ensure the safety of currently regulated hazardous liquid gathering lines. PHMSA recommends that any decision to expand its oversight of gathering lines beyond what is currently regulated or in this final rule should be driven by risk assessment and analysis based on evaluations of incident and accident data, data related to infrastructure, and further technological advancements such as the unconventional production practices used in shale formations.

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

Version Sent to Federal Register

Extreme weather has been a contributing factor in several pipeline failures. For example, in July 2011, a pipeline failure occurred near Laurel, MT, 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. The operator estimated the cleanup costs at approximately $135 million. In 1994, flooding in Texas led 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 PHMSA has noted in a series of Advisory Bulletins, hurricanes are also 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, 2005 (70 FR 53272); Hurricane Rita, September 1, 2011 (76 FR 54531)).

These events demonstrate the importance of working to ensure that our nation's waterways and the public are adequately protected from pipeline risks in the event of a natural disaster or extreme weather. PHMSA is aware that some operators might perform inspections following such events; however, because it is not a requirement, some operators do not. Therefore, PHMSA is amending the PSR to require that operators commence inspection of their potentially affected assets within 72 hours after the cessation of an extreme weather event such as a hurricane, landslide, flood, earthquake, natural disaster, or other similar event that has the likelihood to damage infrastructure.

Specifically, under this requirement, an operator must inspect all potentially affected pipeline facilities following these types of events to detect conditions that could adversely affect the safe operation of the pipeline. The operator must consider the nature of the event and the

Version Sent to Federal Register

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 commence within 72 hours after the cessation of the event, defined as the point in time when the area can be safely accessed by personnel and equipment, including availability of personnel and equipment, required to perform the inspection. PHMSA has found that 72 hours is reasonable and achievable in most cases. If an operator finds an adverse condition, the operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained from 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;
- 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 requirement is based on the experience of PHMSA and is expected to increase the likelihood that operators will find and respond to safety conditions more quickly.

Version Sent to Federal Register

Require Assessments of Pipelines that Are Not Already Covered Under the IM Program Requirements at Least Once Every 10 Years

PHMSA is requiring that operators periodically assess onshore, piggable, transmission pipeline segments in non-HCAs. PHMSA has determined that expanding assessment requirements to these non-HCA pipeline segments will provide operators with valuable information they may not have collected if regulations were not in place. Such a requirement works to ensure prompt detection and remediation of corrosion and other deformation anomalies across the nation, not just in populated or environmentally sensitive areas. Specifically, § 195.416 requires operators to assess onshore, piggable, non-HCA, transmission pipeline segments at least once every 10 years, which allows operators to prioritize assessments in HCAs over assessments in non-HCAs. The individuals who review the results of these assessments will need to be qualified by knowledge, training, and experience and will 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 will 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 are 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, tests, and repairs (see § 195.404); and taking appropriate remedial action under § 195.401(b)(1), as discussed below.

Version Sent to Federal Register

Such requirements will help ensure operators obtain information necessary for the detection and remediation of corrosion and other deformation anomalies in all locations, not just HCAs. Of the many assessment methods, PHMSA has found that ILI in many cases is the most efficient and effective. Operators can perform ILIs while pipelines are in service without any interruption of product flow. Further, ILIs are non-destructive and can provide information beyond direct assessments, which can only tell whether there is exterior coating damage or corrosion, and hydrotests, which are essentially "pass" or "fail." ILI tools, which are constantly improving, can provide accurate information on internal corrosion, external corrosion, cracks, and gouges. Additionally, there is robust guidance and documentation for the use of ILI; API and the National Association of Corrosion Engineers have developed standards for ILIs that provide guidelines on appropriate tool selection, assessment procedures, and the qualification of personnel conducting assessments.

Currently, operators have indicated that they are performing ILI assessments on a large portion of both HCA and non-HCA pipeline mileage, even though no regulation requires them to assess mileage outside of HCAs. Reported repairs outside of could-affect HCA segments reflect this indication. PHMSA wants to best ensure that current assessment rates continue and expand to those areas not voluntarily assessed. PHMSA has determined that by adopting these amendments to the existing pipeline safety regulations, data collection will continue to improve across the entire pipeline system, and anomalies that may have previously gone undetected in non-HCAs will be detected and repaired in a more consistent manner.

Version Sent to Federal Register

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

The current repair criteria do not reflect the proper prioritization of abnormal pipeline conditions found in the field. In 2007, API-AOPL petitioned PHMSA to reconsider the existing repair criteria. Over the past decade, both PHMSA and industry research have found that some conditions within the 60- and 180-day categories were more of an integrity threat than earlier thought and should be moved to the "immediate" repair condition, while others were not so critical that they would fail in 60 or 180 days. PHMSA has received comments from various workshops and stakeholder meetings that have confirmed this, and PHMSA's inspection experience and post-accident investigations corroborate this as well. For these reasons, PHMSA decided to re-designate some of the former 60- and 180-day conditions as immediate conditions and consolidated other non-immediate conditions into a 270-day repair category that takes into account engineering assessments and fatigue factors specific to hazardous liquid pipelines.

Therefore, PHMSA is modifying the criteria in § 195.452(h) for IM repairs to:

- Categorize bottom-side dents with stress risers, pipe with selective seam weld corrosion, and pipe with significant stress corrosion cracking as immediate repair conditions;
- Require immediate repairs whenever the calculated burst pressure is less than 1.1 times MOP. This provides a 10 percent margin of safety over the previous calculation where a repair was required when the calculated burst pressure was less than MOP and takes into account pressure surges and other variations of pressure;
- Establish engineering critical assessment procedures for evaluating certain crack anomalies;

Version Sent to Federal Register

- Eliminate the 60-day and 180-day repair categories; and
- Establish a new, consolidated 270-day repair category.

Operators of both HCA lines and non-HCA lines will have equal requirements for the "discovery" of conditions, which occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable. This would include information as to why such information would not be available prior to that date. If an operator believes that unique circumstances exist in its case making the 180-day period impracticable, the operator must submit a notification to PHMSA and provide an expected date when adequate information will become available. The submission of such a notification, by itself, will not affect compliance determinations on whether the 180-day requirement was met.

Based on experience with failure investigations, metallurgical studies, and root cause analyses, PHMSA has determined that these changes will help to ensure that operators take immediate action to remediate anomalies that present an imminent threat to the integrity of hazardous liquid pipelines in all locations. Moreover, many anomalies in HCAs that would not qualify as immediate repairs under the previous criteria will meet that requirement because of the additional conservatism that PHMSA is incorporating into the burst pressure calculations. The new schedule for performing non-immediate repairs in HCAs will also allow operators to remediate those conditions in a timely manner while allocating resources to those conditions that present a higher risk of harm to the public, property, and the environment.

Version Sent to Federal Register

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

With respect to new hazardous liquid pipelines, PHMSA is amending § 195.134 to require that all new covered pipelines, in both HCAs and non-HCAs, have leak detection systems within 1 year after this rule is published in the Federal Register, and all covered pipelines constructed prior to the rule's publication have leak detection systems within 5 years after this rule is published. Recent pipeline accidents, including a pair of related failures that occurred in 2010 on a crude oil pipeline in Salt Lake City, UT, corroborate the significance of having an adequate means for identifying leaks in all locations. PHMSA, aware of the significance of leak detection, held two workshops in Rockville, MD, 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 on the technical gaps and challenges for future research and ways to leverage resources to achieve common objectives and reduce duplication of research programs. Participants also discussed the development of leak detection for all pipeline types and the capabilities and limitations of current leak detection technologies.

With respect to existing pipelines, part 195 currently contains mandatory leak detection requirements for only those 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 consequences of establishing

Version Sent to Federal Register

additional standards for the use of those systems. Congress authorized the issuance of regulations for leak detection if warranted by the findings of the report.

PHMSA publicly provided the results of the 2012 Kiefner and Associates study on leak detection systems in the pipeline industry, including the current state of technology. The study found that most leak detection technologies can be retrofitted to existing pipelines, though many operators "fear investing in leak detection systems, with potentially little benefit to show from them and no way to truly measure success in a standardized way," resulting in leak detection being implemented "cautiously, and incrementally, on measurement and other systems that are already in place."[18]

Based on information available to PHMSA, including post-accident reviews and the Kiefner Report, the need to expand the use of leak detection systems and strengthen the current leak detection requirements is clear. A robust leak detection system is extremely important to hazardous liquid operators because it triggers all other impact mitigation measures that an operator should plan for, including safe flow shutdown, spill containment, cleanup, and remediation. In this final rule, PHMSA is modifying § 195.444 to require a means for detecting leaks on all portions of a hazardous liquid pipeline system, including non-HCA transmission lines, and requiring that operators perform an evaluation to determine what kinds of systems must be installed to adequately protect the public, property, and the environment. The factors

[18] Kiefner and Associates, Inc., "Final Report on Leak Detection Study-DTPH56-11-D-000001," December 10, 2012; http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Press%20Release%20Files/Leak%20Detection%20Study.pdf

Version Sent to Federal Register

that must be considered during that evaluation include (but are not limited to) the characteristics and history of the affected pipeline, the capabilities of available leak detection systems, and the location of emergency response personnel. PHMSA is retaining the requirements in §§ 195.134 and 195.444 that each new computational leak detection system comply with the applicable requirements in the API RP 1130 standard.

Given the difficulties identified in the Kiefner study related to leak detection performance standards, PHMSA is not making any additional changes to the regulations concerning specific leak detection system performance criteria requirements at this time. PHMSA will be studying this issue further and may make proposals concerning this topic in a later rulemaking.

Increased Accommodation of In-line Inspection Tools

In this final rule, PHMSA is amending the part 195 regulations to require that all hazardous liquid pipelines in HCAs and areas that could affect an HCA be made capable of accommodating ILI tools within 20 years, unless subject to PHMSA approval, the basic construction of a pipeline will not accommodate the passage of such a device or the operator determines it would abandon the pipeline as a result of the cost of complying with the amendment. Per the petition process at § 190.9, operators would be required to document these determinations and submit the documentation to PHMSA for approval.

Modern ILI tools are capable of providing a relatively complete examination of the entire length of a pipeline, including information about threats that other assessment methods cannot always identify. 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

Version Sent to Federal Register

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, but only allows operators to determine whether a required safety margin is met (i.e., pass/fail) and does not provide information about the existence of anomalies that could deteriorate over time between tests. Similarly, external corrosion direct assessment (ECDA) is a form of direct assessment that can identify instances where coating damage may be affecting pipeline integrity, but operators must perform additional activities, including follow-up excavations and direct examinations, to verify the extent of that threat. ECDA also provides less information about the internal condition of a pipe than ILI tools.

The current regulations 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 ILI tools. The basis for these requirements is 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).

As the Research and Special Programs Administration (RSPA) (a predecessor agency of PHMSA), explained in the final rule published on April 12, 1994 (59 FR 17275), that promulgated § 195.120, “the 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.” 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,

Version Sent to Federal Register

including with ILI tools in appropriate circumstances. 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). RSPA established requirements for the use of ILI tools in pipelines that could affect HCAs in a final rule published on 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.

In this final rule, PHMSA is taking steps to further facilitate the gradual elimination of pipelines that are not capable of accommodating smart pigs in accordance with the authority provided in section 60102(f)(1)(B). PHMSA is limiting 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, costs, and other unforeseen construction problems. PHMSA believes that an exception should still be available for

Version Sent to Federal Register

emergencies and where the basic existing construction of a pipeline makes that accommodation impracticable.

Regulations already require that new and replaced pipelines accommodate ILI tools, and many of the pipelines covered by this new rule will need to be replaced and therefore will accommodate ILI tools before the end of the 20-year implementation period. Providing industry with sufficient time to implement this provision allows the industry to prioritize retrofits and replacements based on age or other factors; it also reduces the mileage of pipeline potentially needing to be replaced before it has reached the limit of its operational life. PHMSA determined that the 20-year timeline strikes the appropriate balance between the need for upgrades with the operational challenges of making these changes.

Clarify Other Requirements

In this final rule, PHMSA is also making 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 better harmonize this section with other parts of 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 1 year after the pipeline begins operation. These provisions are inconsistent, as the identification of could-affect segments and performance of baseline assessments are elements of the written IM program. PHMSA is amending the table in (b)(1) to resolve this issue by eliminating the 1-year compliance deadline

Version Sent to Federal Register

for Category 3 pipelines. An operator of a new pipeline is 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 (i.e., they are collecting information, but not affording it sufficient consideration). Integration is one of the most important aspects of the IM program, and operators must account for interactions between threats or conditions affecting the pipeline when 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 necessarily reveal any need for priority attention. PHMSA is concerned that a major benefit to pipeline safety intended in the IM rule is not being realized because of inadequate information analyses.

For this reason, PHMSA is adding specificity to paragraph (g) by establishing a number of pipeline attributes that must be included in these analyses and requiring explicitly that operators integrate analyzed information. PHMSA is also requiring operators to 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 requiring operators to verify their pipeline segment identification (as HCAs or otherwise) annually by determining whether factors considered in their analysis have changed. Section 195.452(b) currently requires that operators identify each segment of their

Version Sent to Federal Register

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. Construction activities or erosion near the pipeline could change local topography in a way that could cause product released in an accident to travel farther 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 release affecting a larger area if the original segment identification relied on emergency response in limiting the transport of released product. Therefore, PHMSA has determined that operators should periodically re-visit their initial analyses to determine whether they need updating; operators might identify new HCAs in subsequent analyses.

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

Further, 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

Version Sent to Federal Register

several points in the IM program guidance provided in Appendix C of 49 CFR part 195, PHMSA is amending the PSR 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.

Finally, the PIPES Act of 2016 contained two sections PHMSA identified as self-executing and that PHMSA could incorporate into the PSR without notice of public comment or previous proposed rulemaking. Section 14 of the PIPES Act of 2016 requires operators of hazardous liquid pipeline facilities to provide safety data sheets to the designated Federal On-Scene Coordinator and appropriate State and local emergency responders within 6 hours of a telephonic or electronic notice of the accident to the National Response Center. Section 25 of the PIPES Act of 2016 requires operators of underwater hazardous liquid pipeline facilities in HCAs that are not offshore pipeline facilities and that any portion of which are located at depths greater than 150 feet below the surface of the water to complete ILI assessments appropriate to the integrity threats specific to those pipelines no less frequently than once every 12 months and use pipeline route surveys, depth of cover surveys, pressure tests, ECDAs, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, as necessary to assess the integrity of those pipelines on a schedule based on the risk that the pipeline facility poses to the HCA in which the facility is located. PHMSA is amending the PSR by codifying the statutory language of these provisions.

III. Liquid Pipeline Advisory Committee Recommendations

Version Sent to Federal Register

The Liquid Pipeline Advisory Committee (LPAC) is a statutorily mandated advisory committee that advises PHMSA on proposed safety standards, risk assessments, and safety policies for hazardous liquid pipelines. The Pipeline Advisory Committees (PAC) were established under the Federal Advisory Committee Act (Pub. L. 92-463, 5 U.S.C. App. 1-16) and the Federal Pipeline Safety Statutes (49 U.S.C. Chap. 601). Each committee consists of 15 members, with membership divided among the Federal and State agencies, the regulated industry, and the public. The PACs advise PHMSA on the technical feasibility, practicability, and cost-effectiveness of each proposed pipeline safety standard.

On February 1, 2016, the LPAC met at the Hilton Arlington in Arlington, VA, to discuss this rulemaking. During the meeting, the LPAC considered the specific regulatory proposals of the NPRM and discussed various comments to the NPRM proposed by the pipeline industry, public interest groups, and government entities. To assist the LPAC in their deliberations, PHMSA presented a description and summary of the eight major issues in the NPRM and the comments received on those issues, as well as some sample regulatory text changes to foster discussion.

During the meeting, eight votes were taken: one vote on each major topic of the rule. For each major topic of the rule, the LPAC came to a consensus decision that the provisions of the proposed rule would be technically feasible, reasonable, cost-effective, and practicable, provided PHMSA made certain changes. The order the topics were discussed in, the changes the committee agreed upon, and the corresponding vote counts were as follows:

Gravity lines: In the NPRM, PHMSA proposed to subject gravity lines to reporting requirements for data gathering purposes, as there are currently no regulatory requirements for

Version Sent to Federal Register

these lines and little data for potential regulatory decision-making purposes. The committee voted 9-1 that the proposed rule, with respect to gravity lines, as published in the Federal Register, and the draft regulatory evaluation were technically feasible, reasonable, cost-effective, and practicable, if PHMSA made the following changes: modify (shorten) the reporting form, require no National Pipeline Mapping System (NPMS) submissions, provide reporting exceptions for lower-risk pipelines (for example, intra-plant lines), allow a 1-year implementation period for annual reporting, and allow a 6-month implementation period for accident reporting.

Committee members agreed that PHMSA should modify the reporting forms to gather only the data necessary for PHMSA to make a determination on whether these lines need to be regulated in the future. Committee members representing the pipeline industry requested that PHMSA consider reporting exceptions for lower-risk pipelines, such as intra-plant gravity lines. The same members also requested that any reporting requirements for gravity lines not include NPMS submissions, asserting that incorporating that data into a mapping system would be costly compared to the amount of risk these lines pose. Carl Weimer of the Pipeline Safety Trust and Chuck Lesniak of the City of Austin, who both represented the public, did not support these recommendations. They noted that as gravity line mileage is already limited, and the reporting requirement is only being used to gather data, excepting a subset of this limited mileage from reporting requirements would be counter-productive. Further, these members strongly suggested that NPMS submissions be included for gravity lines, as location could be an important data point PHMSA could collect.

Version Sent to Federal Register

Gathering lines: In the NPRM, PHMSA proposed to collect information on all gathering lines and subject regulated gathering lines to periodic assessment and leak detection requirements. Much of the committee's discussion for gathering lines mirrored the discussion on gravity lines. Under 49 U.S.C. 60132, only transmission line operators are required to submit mapping data for use in the NPMS. As a result, the committee removed language concerning NPMS submissions by gathering line operators. Ultimately, the committee voted 10-0 that the proposed rule, with regard to gathering lines, as published in the Federal Register, and the draft regulatory evaluation are technically feasible, reasonable, cost effective, and practicable if PHMSA made the following changes: modify (shorten) the reporting form, allow a 1-year implementation period for annual reporting, and allow a 6-month implementation period for accident reporting.

Leak detection: In the NPRM, PHMSA proposed all pipelines include a leak detection system and have it operate and maintained per specified standards. Many commenters noted that there was no implementation period for PHMSA's proposed leak detection requirements. The LPAC proposed a 5-year implementation period for leak detection systems on existing lines and a 1-year implementation period for leak detection systems on new lines. The LPAC also recommended PHMSA not apply leak detection requirements to offshore gathering lines due to various technical challenges associated with flow monitoring and leak detecting. The committee voted unanimously that the proposed rule, with regard to leak detection, as published in the Federal Register, and the draft regulatory evaluation are technically feasible, reasonable, cost effective, and practicable if PHMSA made the following changes: allow a 5-year implementation

Version Sent to Federal Register

period for existing pipelines, allow a 1-year implementation period for new pipelines, and exempt offshore gathering lines from the leak detection requirements.

Clarifying other requirements: In the NPRM, PHMSA proposed to revise the IM requirements to specify additional pipeline attributes for operators to analyze when evaluating the integrity of pipelines in HCAs; to require the integration of all sources of information, including spatial relationships, when determining pipeline integrity; to require operators have a written IM plan prior to a specific pipeline's operation; and to require annual HCA segment identification and verification. During the meeting, the LPAC primarily discussed whether there should be a timeframe for implementing the specific data attributes and integrating all sources of information when determining pipeline integrity. Committee members representing the public argued that, because these provisions were clarifications of existing requirements, operators should have already been performing many of these actions, and an extended implementation period would not make sense. Several members who represented the public pushed for a 1-year implementation period. Committee members representing the industry noted that developing data integration systems to a level that PHMSA would like could be expensive and time-consuming, possibly taking several years. Further, committee members representing industry noted that while a lot of data integration is already occurring in operators' IM programs, it could take some operators an extended period to adjust their software to incorporate all of the items in PHMSA's proposed list. Committee members representing industry proposed PHMSA allow operators a 3-year deadline from the rule's issuance to fully implement the proposed list of attributes. Ultimately, the committee voted 7-3 that the proposed rule, with regard to the data integration requirements, as published in the Federal Register, and the draft regulatory evaluation are

Version Sent to Federal Register

technically feasible, reasonable, cost-effective, and practicable if operators begin implementing the requirements upon the rule's issuance with a deadline of 3 years for full implementation.

Inspections following extreme weather events: In the NPRM, PHMSA proposed requiring operators to perform inspections of pipelines that may have been affected by natural disasters or extreme weather events within 72 hours after the cessation of the event to better ensure that no conditions exist that could adversely affect the safe operation of that pipeline. The committee voted unanimously that the proposed rule, as it relates to inspections following extreme weather events, as published in the Federal Register, and the draft regulatory evaluation are technically feasible, reasonable, cost-effective, and practicable, if PHMSA makes the following changes to the proposed §195.414:

In paragraph (a), "General," include "landslide" as a specific extreme weather event. Qualify "other similar events" that trigger an inspection with "that the operator determines to have a significant likelihood of damage to infrastructure." Clarify that the purpose of the inspection is to "detect conditions that could adversely affect the safe operation of that pipeline," and not, as proposed, "ensure that no conditions exist that could adversely affect the safe operation of that pipeline," which commenters noted may be impossible to achieve.

In paragraph (b), "Inspection method," clarify that the inspection required by this section is an "initial" inspection with the purpose of determining "damage and the need for additional assessments."

In paragraph (c), "Time period," clarify that the inspection required by this section must "commence" within 72 hours after the cessation of the event, which will be defined as the point when the affected area can be safely accessed by personnel and equipment, taking into

Version Sent to Federal Register

consideration the availability of personnel and equipment. Committee members representing industry noted that, following a large-scale disaster like Hurricane Katrina in 2005, it was extremely difficult to obtain inspection resources. The committee agreed that operators might need some flexibility for when inspections must begin in similar circumstances.

Periodic assessments in non-HCAs: In the NPRM, PHMSA proposed to require operators to assess non-HCA pipelines at least once every 10 years using ILI or other equivalent methods. The committee agreed on this requirement and wanted to ensure it was not more restrictive than the requirement for assessing lines in HCAs. The committee voted unanimously that, with regard to the provisions of the proposed rule related to periodic assessments, the proposed rule, as published in the Federal Register, and the draft regulatory evaluation are technically feasible, reasonable, cost-effective, and practicable if PHMSA makes the following changes to §195.416:

In paragraph (a), "Scope," ensure that the periodic assessment requirement applies to regulated pipelines that are not currently subject to the IM requirements at §195.452.

In paragraph (c), "Method," make the method operators use to assess non-HCA pipelines consistent with the method operators use to assess HCA pipelines and allow operators to choose the appropriate tool for the appropriate threat.

Making all pipelines in HCAs able to accommodate ILI tools: In the NPRM, PHMSA proposed to require all pipelines in HCAs be capable of accommodating ILI tools within 20 years. The committee voted 9-1 that, with regard to the provision of the rule requiring the use of ILI tools in all HCAs, the proposed rule, as published in the Federal Register, and the draft regulatory evaluation are technically feasible, reasonable, cost-effective, and practicable provided PHMSA make the following changes to §195.452(n):

Version Sent to Federal Register

In paragraph (4), "Lack of accommodation," insert a phrase stating that an operator can also file a petition if it determines it would abandon or otherwise shut down a pipeline because of the compliance cost of paragraph (n).

Repair criteria: In the NPRM, PHMSA proposed to make various changes to the existing repair criteria to reflect an improved prioritization of repairing abnormal pipeline conditions. The committee voted unanimously that, with regard to repair criteria for both HCA and non-HCA pipeline segments, the proposed rule, as published in the Federal Register, and the draft regulatory evaluation are technically feasible, reasonable, cost-effective, and practicable if PHMSA considers allowing recognized engineering analyses to determine whether applicable dents and cracks are non-injurious and need no further investigation, and gives "full and equal consideration to the industry comments that were discussed [at the meeting]."[19] Those industry comments were as follows:

Repair Criteria for both HCA and non-HCA pipeline segments:

1. With regard to "Immediate" conditions:
    a. Include crack anomalies greater than 70 percent of wall thickness or the tool's maximum measurable depth if it is less than 70 percent;
    b. Remove specific references to "any indication" of significant stress corrosion cracking (SCC) and selective seam weld corrosion (SSWC).

[19] At the Advisory Committee meeting, member Craig Pierson, representing the pipeline industry, submitted for the members' consideration a written recommendation regarding repair criteria anomalies.

Version Sent to Federal Register

c. Allow for an industry recognized engineering analysis to determine those dents that are non-injurious and require no further investigation; and

d. Instead of addressing cracks and SSWC specifically, expand the various accepted failure models that identify an anomaly that does not have the remaining strength to exceed 1.1 times the MOP at the location of the anomaly, which should also include injurious cracks and SSWC.

2. With regard to 270-day conditions for HCAs and 18-month conditions for non-HCAs:

   a. Revise the existing reference to cracks and include crack anomalies greater than 50 percent of wall thickness or the tool's maximum measurable depth if it is less than 50 percent;

   b. Allow for an industry recognized engineering analysis to determine those dents that are non-injurious and require no further investigation; and

   c. To address cracks and SSWC, expand the various accepted failure models that identify an anomaly that does not have the remaining strength to exceed 1.25 times the MOP at the location of the anomaly.

3. Add a "Scheduled condition:"

   a. Anomalies that do not meet the 270-day or the 18-month repair criteria but have the possibility to grow before the next segment inspection are subject to predictive modeling of remaining strength; and

   b. Investigate in the years prior to the next inspection if the predicted burst pressure is less than 1.1 times the MOP at the location of the anomaly.

Version Sent to Federal Register

In this final rule, PHMSA considered the recommendations of the LPAC and adopted them as PHMSA deemed appropriate. To summarize, the major changes from the LPAC recommendations are as follows: 1) PHMSA added an additional requirement for operators to notify the appropriate PHMSA Region Director when unable to inspect infrastructure impacted by extreme weather within 72 hours; 2) PHMSA is allowing a specified engineering critical assessment (ECA) to extend the repair deadline with regard to SCC and SSWC but not for dents; 3) PHMSA changed a word regarding the regulatory text for non-HCA assessments, in that operators must assess "line pipe" (instead of "pipelines defined under § 195.1") not subject to the IM requirements at § 195.452; 4) PHMSA restricted the non-HCA periodic assessment requirement to onshore, piggable, transmission line pipe only, which removed the proposed assessment requirement for covered offshore lines and for regulated rural gathering lines; 5) PHMSA removed the leak detection requirement for rural regulated gathering lines at § 195.11; and 6) PHMSA did not move forward with the non-HCA repair criteria and timelines as proposed and instead reverted back to the existing non-IM repair language at § 195.401(b)(1). In the comments section, for each major topic of the rule, PHMSA broadly discusses specific amendments proposed during the meeting and the corresponding discussion. PHMSA also discusses the instances where PHMSA did not adopt the specific recommendations of the LPAC.

IV. Analysis of Comments and PHMSA Response

On October 13, 2015, PHMSA published an NPRM (80 FR 61609) proposing several amendments to 49 CFR part 195. The NPRM proposed amendments addressing the following areas:

Version Sent to Federal Register

1) Reporting requirements for gravity lines

2) Reporting requirements for gathering lines

3) Inspections of pipelines following extreme weather events

4) Periodic assessments of pipelines not subject to IM

5) Repair criteria

6) Expanded use of leak detection systems

7) Increased use of in-line inspection tools

8) Clarifying other requirements

Seventy organizations and individuals submitted comments in response to the NPRM:

- Associations representing pipeline operators (trade associations)
  - Accufacts
  - American Gas Association (AGA)
  - American Petroleum Institute-Association of Oil Pipelines (API-AOPL)
  - Denbury Resources
  - Energy Transfer Partners (ETP)
  - Enterprise Products Partners (EPP)
  - FlexSteel
  - Gas Processors Association (GPA)
  - General Electric Oil & Gas (GEOG)
  - Independent Petroleum Association of America (IPAA)
  - International Liquid Terminals Association (ITLA)
  - Louisiana Mid-Continent Oil and Gas Association (LMOGA)
  - Marcellus Shale Coalition (MSC)
  - McChord Pipeline Co.
  - Offshore Operators Committee (OOC)
  - Ohio Oil and Gas Association (OOGA)
  - Praxair
  - Spectra Energy Partners
  - Texas Oil & Gas Association (TOGA)

Version Sent to Federal Register

- Texas Pipeline Association (TPA)
- Western Refining
- Western States Petroleum Association (WSPA)

- Government/Municipalities
  - Alaska Department of Environmental Conservation
  - Assembly Member Das Williams, California State Assembly
  - Commonwealth of Virginia Department of Conservation and Recreation (on behalf of the Virginia Cave Board)
  - County of Santa Barbara, California
  - Montana Department of Environmental Quality
  - State of Washington Utilities and Transportation Commission

- Government/Federal
  - Congresswoman Lois Capps
  - National Transportation Safety Board (NTSB)
  - Pipeline Safety Regulators National Association of Pipeline Safety Representatives (NAPSR)

- Citizens' Groups
  - Alaska Wilderness League, Conservation Lands Foundation, Cook Inletkeeper, Friends of the Earth, Northern Alaska Environmental Center, The Ocean Foundation, Sierra Club, The Wilderness Society (Alaska Wilderness League et al.)
  - Alliance for Great Lakes, Center for Biological Diversity, For Love of Water, National Wildlife Federation, and Natural Resources Defense Council (Alliance for Great Lakes et al.)
  - Audubon Society of New Hampshire (ASNH)
  - Cook Inlet Regional Citizens Advisory Council (CRAC)
  - Copper County Alliance (CCA)
  - Dakota Rural Action (DRA)
  - Earthworks
  - Environmental Defense Center (EDC)
  - Environmental Law & Policy Center (ELPC)
  - Gulf Restoration Network (GRN)
  - League of Women Votes of California (LWVC)
  - Pipeline Safety Coalition (PSC)
  - Pipeline Safety Trust (PST)

Version Sent to Federal Register

- St. Croix River Association (SCRA)
- State of Washington Citizens Advisory Committee on Pipeline Safety
- The Michigan Coalition to Protect Public Rights-of-Way
- Tip of the Mitt Watershed Council
- Western Organization of Resource Councils (WORC), including 188 citizen letters.

- 22 Private Citizens

Out-of-Scope Comments

Some of the comments PHMSA received in response to the NPRM were comments beyond the scope or authority of the proposed regulations. The absence of amendments in this proceeding involving other pipeline safety issues (including several topics listed in the ANPRM) does not mean that PHMSA determined additional rules or amendments on other issues are not needed. Such issues may be the subject of other existing rulemaking proceedings or future rulemaking proceedings.

The remaining comments reflect a wide variety of views on the merits of particular sections of the proposed regulations. The substantive comments received on the NPRM are organized by topic below and are discussed in the appropriate section with PHMSA's response and resolution to those comments.

A. *Reporting Requirements for Gravity Lines*

1. PHMSA's Proposal

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

Version Sent to Federal Register

pressure because they traverse areas with significant elevation changes, which could have significant consequences in the event of a release.

In order for PHMSA to effectively analyze gravity line safety performance and risk, PHMSA needs basic data about those pipelines. The agency has the statutory authority to gather data for all pipelines (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 proposed to add § 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.

2. Summary of Public Comment

PHMSA received comments from trade organizations, citizen groups, and individuals on the scope and format of the reporting requirements. To reduce the reporting burden, industry representatives (API-AOPL, GPA and ETP) recommended that PHMSA create a new abbreviated annual report with input from operators to separate the reporting of pipeline data for regulated pipelines and those not currently subject to 49 CFR part 195. Specifically, API noted that pipelines not currently covered under part 195 (gravity lines) are not subject to operator qualification, control room management, leak detection, and HCA requirements, and therefore those areas should be excluded from reporting. The Texas Pipeline Association requested that reporting be limited to annual and incident reports, a suggestion also supported by the ETP. API-AOPL commented that industry experience indicates that the cost and time burdens associated with the reporting requirements for gravity lines exceeded the cost estimate cited by PHMSA in the NPRM.

Version Sent to Federal Register

The Environmental Defense Center requested that the reporting requirements include the location, operation, condition, and history of the pipelines, and multiple citizen groups requested that GIS mapping be required for pipelines. In addition to GIS mapping information, the Western Organization of Resource Councils and the Alliance for Great Lakes et al. recommended that PHMSA also require pipeline operators to meet minimum safety standards for all pipelines, a comment echoed by numerous other citizen groups and individuals. These commenters also requested that inspection reports, notices of violation, and similar documents be made readily available to the public.

Trade organizations made additional comments regarding the applicability and implementation timeline for the reporting requirements. API-AOPL and other industry representatives requested that the data collection be narrowed, such that it would apply only to those gravity lines that could present a risk to the public, which: 1) travel outside of facility boundaries for at least 1 mile, 2) operate at a specified minimum yield strength level of twenty percent or greater, and 3) are not otherwise exempted in § 195.1(b). On this same basis, Denbury Resources added a request to exempt CO_2 pipelines. Finally, API-AOPL requested that PHMSA extend the proposed implementation period to 1 year after the effective date of the final rule.

During the February 1, 2016, meeting, the LPAC recommended that PHMSA modify the proposed rule to 1) require reporting from gravity pipeline operators using streamlined forms, 2) not require integration of gravity lines into NPMS, 3) provide exceptions for lower-risk pipelines (e.g., intra-plant lines), and 4) set a 1-year implementation period for the annual reporting requirement and a 6-month implementation period for the accident reporting requirement.

Version Sent to Federal Register

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the scope and timing of the requirements for gravity lines. After considering these comments and LPAC input, PHMSA is modifying the exception for gravity lines at § 195.1 as it pertains to reporting requirements. This change will allow PHMSA to require operators of gravity lines to report information annually, starting 1 year from the rule's effective date, and to report accidents and safety-related conditions starting 6 months from the rule's effective date. PHMSA considers these deadlines practicable in view of the limited scope of the information requested for these lines.

PHMSA focused collection on those data elements that will enable the agency to assess the risk posed by these lines and determine whether requirements that are more stringent are warranted in the future. To facilitate reporting and address commenters' concerns about providing clear instructions on data elements that operators must fill out for gravity lines, PHMSA has modified its existing reporting form to provide clear instructions, including skip patterns, for relevant sections. In response to API's specific suggestions regarding operator qualification, control room management, leak detection, and HCA reporting, these revisions exempted gravity lines from any fields that involve "Could Affect HCA" data. This targeting of the information collection request will reduce the burden associated with providing the information, as was requested by commenters. PHMSA recognizes that operators who are not currently submitting data will have to register with PHMSA to obtain an Operator Identification Number under §195.64, but the associated burden is minimal; PHMSA estimates that fewer than

Version Sent to Federal Register

10 operators would need to submit information for gravity lines. PHMSA estimates the total reporting burden at 66 hours per year, on average.

During the LPAC meeting, the committee reached consensus on requiring gravity line operators to report safety-related conditions. These conditions could lead to significant consequences and are important data points for PHMSA to determine whether additional gravity line regulations may be necessary in the future.

As explained previously, the purpose of the information collection is to support evaluation of the risk posed by gravity lines on the public. With this goal in mind, PHMSA is receptive to commenters who noted that pipelines located within the confines of a facility or in close proximity (within 1 mile) to a facility and do not cross a waterway currently used for commercial navigation pose a lower risk to the public and the environment. PHMSA has decided to exempt these lines from the reporting requirements. The language for this exception is similar to the language of an existing exception for low-stress pipelines at §195.1.

Further safety-related condition reporting exceptions at §195.55(b) will help minimize the reporting burdens for operators. In the NPRM, PHMSA did not intend to propose requiring mapping of gravity lines at this time and therefore is finalizing the rule without this requirement. PHMSA understands commenters' concerns that gravity line NPMS data submissions could be costly and burdensome. However, as PHMSA is not requiring these submissions as a part of this final rule's reporting requirements, the cost and burden of these submissions were not and should not be considered as a part of the cost-benefit analysis. If PHMSA determines, following analysis of the data received on gravity lines, that mapping of these lines or expanding reporting

Version Sent to Federal Register

applicability to lines exempted in this final rule would be beneficial to improve public safety or protect the environment, it may consider additional requirements in a future rulemaking.

Similarly, PHMSA is not requiring telephonic reporting of accidents involving gravity lines at this time but may reassess this requirement in a future rulemaking if analyses of the data suggest that doing so would enhance prevention, preparedness, and response to hazardous liquid releases from gravity lines.

Comments relating to public reporting and the reporting of specific pipeline attributes discussed issues that PHMSA did not propose in the NPRM and are therefore out-of-scope and could not be considered for this rulemaking. Similarly, comments discussing minimum safety standards be applied to gravity lines were also out-of-scope because they requested more stringent requirements than what PHMSA proposed in the NPRM.

B. *Reporting Requirements for Gathering Lines*

1. PHMSA's Proposal

In the NPRM, PHMSA also proposed to extend the reporting requirements of 49 CFR part 195 to all hazardous liquid gathering lines. Recent data indicates 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.[20] 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.

[20] GAO-12-388: "Pipeline Safety: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety," March 2012, pg. 7; http://www.gao.gov/assets/590/589514.pdf

Version Sent to Federal Register

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"[21] that was performed by the Oak Ridge National Laboratory and published on May 8, 2015, PHMSA proposed additional regulations to help ensure the safety of hazardous liquid gathering lines.

In order for PHMSA to effectively analyze safety performance and 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 proposed 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.

2. Summary of Public Comment

Version Sent to Federal Register

21 http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/report_to_congress_on_gathering_lines.pdf

PHMSA received comments on gathering lines that echoed those for gravity lines. Citizen groups and individuals again requested that the requirements for these lines include GIS mapping and minimum safety standards; that the reporting include location, operation, condition, and history; and that inspection reports, notices of violation, and similar documents be made available to the public. Trade organizations again commented on compliance costs and recommended that the reporting requirement be limited to annual and incident reports with an abbreviated form, have a phase-in implementation over 1 year, and exempt lower-risk pipelines. Specifically, API noted again that, as rural gathering lines are not subject to operator qualification, control room management, leak detection, and HCA requirements, those areas should be excluded from reporting.

Trade organizations also made a number of additional recommendations related to the scope of applicability, the scope of requirements, and implementation. The IPAA commented that PHMSA exceeds its authority in requiring operators of gathering lines to submit annual, safety-related condition, and incident reports. The GPA and other organizations noted that PHMSA did not fully account for the burden increase and cost of the reporting requirements for gathering lines in the Regulatory Impact Analysis. The GPA recommended that information requested under §195.61 and §195.64 be excluded from data collection. Numerous trade organizations identified accident reporting for these lines as costly and duplicative. The Louisiana Mid-Continent Oil and Gas Association (LMOGA) submitted that most if not all of the accident information requested for gathering lines is already required to be reported under other existing Federal and State regulations, and the GPA recommended that information collected through an abbreviated Annual Report could be paired with Accident Reporting on

Version Sent to Federal Register

Form F 7000-1 (rev 7-2014). LMOGA also recommended that mapping of gathering lines not be required because of incidental environmental impacts on wetlands, permitting, and resource costs for teams to enter wetlands and track these lines.

The Offshore Operators Committee (OOC) requested that PHMSA make clear in the final rule that the agency's intent is not to have the proposed reporting requirements apply to gathering lines offshore within State waters that are currently not regulated by PHMSA or the Bureau of Safety and Environmental Enforcement (BSEE) or to other gathering lines that are regulated by BSEE.

Finally, commenters asked for implementation periods that ranged from 1 year (API-AOPL) to 10 years (Enterprise Products Partners) after the effective date of the rule.

During the meeting on February 1, 2016, the LPAC recommended that PHMSA modify the proposed rule to 1) require reporting from gathering pipeline operators using streamlined forms and 2) set a 1-year implementation period for the annual reporting requirement and a 6-month implementation period for the accident reporting requirement.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the scope and timing of the requirements for gathering lines. Regarding the comment that the proposed reporting requirement of § 195.1(a)(5) exceeds PHMSA's statutory authority, PHMSA notes that the Federal Pipeline Safety Statutes state, in relevant part, "The Secretary may require owners and operators of gathering lines to provide the Secretary information pertinent to the Secretary's ability to make a determination as to whether and to what extent to regulate gathering lines." 49

Version Sent to Federal Register

U.S.C. 60117(b). PHMSA has determined that in order to decide whether and to what extent to regulate gathering lines, as permitted by Congress, PHMSA requires pertinent information about those pipelines, including elements of the data contained in annual, safety-related condition, and incident reports. With this reporting requirement, PHMSA is not encroaching on the States' regulatory authority, nor creating new jurisdiction. Rather, PHMSA is collecting pertinent information to determine if future regulation is necessary for the statutory purpose of promoting pipeline safety.

PHMSA is finalizing the requirement for operators of gathering lines to report information annually, starting 1 year from the rule's effective date, and to report accidents and safety-related conditions starting 6 months from the rule's effective date. PHMSA considers these deadlines practicable in view of the scope of the information requested. To facilitate reporting and address commenters' concerns about providing clear instructions on data elements that must be filled out for gathering lines, PHMSA has modified its existing reporting form to provide clear instructions, including skip patterns, on the relevant sections that gathering line operators must fill out. In response to API's specific suggestions regarding operator qualification, control room management, leak detection, and HCA reporting, these revisions exempted rural gathering lines from any fields that involve "Could Affect HCA" data. PHMSA recognizes that operators who are not currently submitting data will have to register for an identifier, but PHMSA expects the burden on operators to do this is small. In its analysis, PHMSA assumed that a majority of the reporting of currently unregulated gathering lines would be done by operators who already have OpIDs. PHMSA estimates that, at a minimum, approximately 20 operators will need to submit information for gathering lines for the first time,

Version Sent to Federal Register

and another 56 operators will add information about gathering lines to their existing annual reports. PHMSA estimates the total reporting burden at 402 hours per year, on average. The revised RIA accompanying the final rule presents these estimates.

Some commenters requested PHMSA clarify whether these reporting requirements applied to offshore gathering lines in State waters. PHMSA retained the existing § 195.1(b), which contains exemptions for offshore gathering lines in State waters, so these lines would be exempted from the proposed reporting requirements. The purpose of the information collection is to support evaluation of the public risk posed by gathering lines.

In its proposal, PHMSA did not intend to require mapping or NPMS submissions for gathering lines at this time. Under 49 U.S.C. 60132, only transmission line operators are required to submit mapping data for use in the NPMS. PHMSA is therefore finalizing the rule without imposing this requirement on operators of gathering lines.

Similar to requirements for gravity lines, PHMSA is not requiring telephonic reporting of accidents involving gathering lines to PHMSA at this time since such a requirement would not support the purpose of this data collection effort, which is to enable PHMSA to evaluate risk over time for potential future action. PHMSA notes that operators must still report spills to the National Response Center and other relevant authorities. PHMSA will reassess the utility of requiring notification for incidents involving gathering lines in a future rulemaking if the analyses suggest that such notifications would enhance prevention, preparedness, and response to hazardous liquid releases from gathering lines.

Certain commenters also stated their belief that PHMSA neglected to account for the costs and burden associated with the initial compiling of the data needed to complete the forms.

Version Sent to Federal Register

In many cases, the commenters suggested, information may not have been recorded or may not have been provided during mergers or acquisitions. PHMSA noted in the RIA that it expects operators to have the requested information readily available, as it is essential for pipeline operation and safety. PHMSA allows operators to enter "unknown" when values cannot be determined for certain data fields. In the burden estimate, PHMSA allotted time for operators to compile the proper data and organize it into the requested format. See the RIA for further details.

As in the case of the comments on gravity lines, comments relating to public reporting and the reporting of specific pipeline attributes discussed issues that PHMSA did not propose in the NPRM and are therefore out-of-scope and could not be considered for this rulemaking. Similarly, comments discussing minimum safety standards applied to currently unregulated gathering lines were also out-of-scope because they requested more stringent requirements than PHMSA proposed in the NPRM.

C. *Pipelines Affected by Extreme Weather and Natural Disasters*

1. PHMSA's Proposal

Recent 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 proposed 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.

Version Sent to Federal Register

Specifically, PHMSA proposed that an operator must inspect all potentially affected pipeline facilities after an extreme weather event to help 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 initial inspection must occur within 72 hours after the cessation of the event, defined as the point in time when the affected area can be safely accessed by available personnel and equipment required to perform the inspection. Based on PHMSA's experience and coordination with operators following natural disasters, PHMSA has found that 72 hours is reasonable and achievable in most cases. If an operator finds an adverse condition, the operator must take appropriate remedial action to best ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection. PHMSA specifically asked for comments on how operators currently respond to these events, what type of events are encountered, and if a 72-hour response time is reasonable.

2. Summary of Public Comment

Some trade organizations recommended that certain requirements be eliminated altogether or consolidated to reduce what they considered to be duplicative of existing emergency planning requirements in § 195.402(e)(4).

Commenters were nearly unanimous in requesting that PHMSA clarify the definition of extreme weather event, the 72-hour timeline, and the timeline for mitigating or repairing anomalies. The GPA recommended that PHMSA either define exactly which events require

Version Sent to Federal Register

response and inspection or establish performance expectations without partially defining the criteria, while the County of Santa Barbara recommended that the proposed regulations specify a particular threshold at which action would be required. Congresswoman Lois Capps recommended that PHMSA include definitions and/or citations of existing definitions for qualifying events and the responsible party for such a determination. Congresswoman Capps also recommended that PHMSA clarify the terminology for an "appropriate method for performing the inspection" after the event.

In addition to clarification of the definition of extreme weather event, trade groups also requested clarification of the 72-hour timeline following an extreme weather event, including how they would determine the cessation of the event, what appropriate action they would need to take following an event, and how to address the possibility of continued danger facing personnel or issues with availability of personnel and resources following an event.

API-AOPL recommended that PHMSA define cessation as the point in time when no further threats to personnel safety or equipment exist in the affected area, allowing for safe access by pipeline personnel and equipment. They also recommended that the 72-hour window commence only once personnel and equipment could safely access the affected area.

Citizen groups and individuals requested that operators be required to proactively address known risks and vulnerabilities in advance of an extreme weather event. For example, the SCRA recommended additional requirements to identify areas that are particularly vulnerable to extreme weather events or natural disasters, e.g., stream crossings, and to develop proactive preventative measures. The Alaska Wilderness League et al. recommended mandatory prevention measures that include shutting down pipeline operations in case of an imminent flood

Version Sent to Federal Register

in order to prevent spills such as the Exxon Mobil 2011 Yellowstone River spill. Citizen groups also requested immediate reporting to PHMSA when remedial action is required and that this information be made publically available. The Environmental Defense Center requested that PHMSA provide specific, enforceable requirements for shutdown or other remedial action should an inspection reveal damage or anomalies, and that PHMSA clarify the type of events covered and the inspection methodology required.

Finally, the OOC recommended that PHMSA coordinate with BSEE and the Coast Guard for activities that occur after hurricanes.

During the meeting on February 1, 2016, the LPAC recommended that PHMSA modify the proposed rule to 1) include landslides as an extreme weather event, 2) clarify that other similar events are those likely to damage infrastructure, and 3) require operators to inspect all potentially affected pipeline facilities to detect conditions that could adversely affect the safe operation of the pipeline. The LPAC also recommended that PHMSA modify the language regarding the inspection method to require operators 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 initial inspection to determine damage and the need for additional assessments. Finally, the LPAC recommended that PHMSA clarify that the inspection must commence within 72 hours after the cessation of the event, which is defined as the point in time when the affected area can be safely accessed by the personnel and equipment, accounting for personnel and equipment availability.

3. PHMSA Response

Version Sent to Federal Register

PHMSA disagrees with the comments stating the provisions at § 195.414 are unnecessary and duplicate operation and maintenance (O&M) manual requirements already contained in the response plan requirements under § 195.402. While §195.402 does require that operators include certain ongoing monitoring measures in their O&M manuals, the proposed §195.414 is much more specific in requiring that operators take appropriate remedial action to best ensure the safe operation of a pipeline based on the information obtained as a result of performing the post-event inspection required under paragraph (a) of this section. This will ensure that operators take the prescribed actions; having measures described in an operator's O&M manual, as previously required, is not equivalent to action. PHMSA maintains that separate and more specific requirements are warranted to best ensure public safety and environmental protection following extreme events. Additionally, PHMSA notes that reporting is coordinated with BSEE, the United States Coast Guard, and other agencies under existing notification procedures if the assessment determines there was a release involving their areas of responsibility. Both 49 CFR parts 194 and 195 require operators to report spills to the National Response Center.

PHMSA appreciates the feedback provided by the commenters regarding the need for greater clarity in the definition of extreme events and natural disasters and expectations on the timing and scope of post-event inspections. In developing the requirements, PHMSA sought to balance being explicit regarding the types of events that could increase the risk of a release and therefore require inspections, with providing sufficient flexibility to account for diverse geographical and pipeline design factors. PHMSA recognizes that the language recommended by the LPAC is useful in striking this balance and adopted the revisions in the final rule under §§ 195.414(a), (b), and (c). PHMSA retained the remedial actions unchanged from the proposal.

Version Sent to Federal Register

While PHMSA intends for operators to inspect pipelines as soon as possible after an event ends, PHMSA also agrees with commenters that personnel safety is paramount. Accordingly, PHMSA clarified that the cessation of the event occurs as soon as it is safe for personnel and equipment to access the area. In response to commenters who sought greater flexibility in the timing of the inspections by leaving it up to the operators, PHMSA disagrees and maintains that setting clear and consistent timelines is essential to ensuring that all operators detect and address any issues promptly. The final rule does provide a fallback to operators who must delay the start of actions beyond this time due to availability of equipment, but these operators must notify the Regional Director. This addition to the LPAC-approved language allows operators to retain flexibility due to unavailable equipment, while ensuring accountability and prompt action. PHMSA considers 72 hours to be a reasonable period for mobilizing personnel and equipment following an event. In response to commenters who expressed concerns that inspections cannot be reasonably be completed within the 72-hour window, PHMSA notes that the proposal did not require *completion* of the inspections within 72 hours, and neither does the final rule; PHMSA recognizes that this needed to be clarified in the rule text and has done so in the final rule. The final rule accordingly describes the actions it expects operators to perform, starting within 72 hours after the cessation of the event. Recognizing that some actions will need to be site-specific, PHMSA provides flexibility to operators to determine the measures that are appropriate to the event, pipeline design, and circumstances.

PHMSA is receptive to the recommendation that operators should take precautionary measures to minimize exposure in advance of an extreme event (e.g., reducing operating pressure or shutting down a pipeline), and notes that the current IM regulations require operators to know

Version Sent to Federal Register

and understand risks to their system, which includes the threat of extreme events such as flooding or wind damage. In order to execute their IM programs and assessments on non-HCA lines as per this final rule, operators will need to have information on virtually all their pipeline system in order to address risks to their systems. Operators will use the information they have gathered on their entire pipeline system to monitor conditions and determine any anticipated risks to their pipelines, including extreme weather events. Given that the existing IM regulations require preventive and mitigative measures for HCAs, which often include river crossings, it is appropriate for this section to address post-natural disaster inspections for damage specifically.

D. *Periodic Assessment of Pipelines Not Subject to IM*

1. PHMSA's Proposal

PHMSA proposed to require integrity 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 help 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 ILI tool at least once every 10 years, which allows operators to prioritize HCA assessments. PHMSA proposed to allow other assessment methods if an operator provides OPS with prior written notice that a pipeline is not capable of accommodating an ILI tool. Such alternative technologies would include hydrostatic pressure testing or appropriate forms of direct assessment.

Version Sent to Federal Register

Although imposing the full set of IM requirements in § 195.452 on non-HCA pipeline segments was not proposed, operators would be required to comply with the other provisions in 49 CFR 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. Operators would also follow the requirements for "discovery of condition," where the discovery of a condition occurs when an operator has adequate information to determine that a condition exists. The operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to determine whether the condition could adversely affect the safe operation of the pipeline, unless 180 days is impracticable as determined by PHMSA. PHMSA sought public comment on the alternatives it considered under this specific proposal and on quantifying these alternatives in the regulatory impact analysis.

2. Summary of Public Comment

Trade organizations offered comments and language revisions on the methods and requirements included in the periodic assessments, implementation period, inspection intervals, and exemptions for lower risk pipelines. Enterprise Products Partners requested that operators be afforded the latitude they have under current IM regulations to determine the actual threats to pipeline integrity present on a given segment and to tailor their integrity assessment program accordingly. For instance, Enterprise suggested that PHMSA revise the proposal to clarify that a

Version Sent to Federal Register

crack tool is not required for every ILI assessment, stating specifically that "an additional ILI crack tool is beneficial only when there is an identified threat to the pipeline segment that could result in cracks, such as cyclic fatigue. Yet PHMSA proposes to require a [crack tool] in all circumstances and on every pipeline segment." Other trade organizations echoed this and requested that PHMSA incorporate alternatives to ILI tools for periodic assessments into the rule. Trade organizations also recommended that PHMSA ensure the rule is consistent with existing IM rules, including the reassessment intervals and implementation period. The Texas Pipeline Association requested that reassessment intervals be based on sound engineering judgement and industry consensus standards. Finally, trade organizations recommend that PHMSA limit and specify the type of pipelines to which the requirement would apply, with some commenters requesting specific exemptions for short lines and CO_2 pipelines. API-AOPL requested that PHMSA clarify that operators would not need to run assessments on idle or out-of-service pipelines. API-AOPL also requested that PHMSA clarify that it intends for the requirements to include transmission lines only. Finally, the GPA requested that PHMSA rely on American Society of Nondestructive Testing (ASNT) ILI PQ as the standard for data analysis rather than the current language "qualified by knowledge, training, and experience." The GPA submitted additional comments to PHMSA on March 24, 2016, expressing concerns that PHMSA misrepresented aspects of this proposal during the LPAC meeting. In the LPAC meeting the GPA claimed that PHMSA asserted that currently regulated gathering lines are subject to assessments; the GPA believes that this statement was inaccurate and led to a vote by the committee that was not based on accurate facts. Further, the GPA suggested that "it is possible there are gathering lines in non-rural areas which do not meet the Census Bureau

Version Sent to Federal Register

definitions for high or other population areas. Thus, when properly applying the regulations as currently written, there are gathering lines, which are regulated by PHMSA and its state partners for safety purposes that are not subject to periodic assessments."

Trade organizations also commented on the cost of expanding requirements for pipelines located outside of HCAs. The Texas Pipeline Association commented that raising the level of regulation on facilities outside of HCAs will redirect resources from high-risk areas to lower-risk areas. They requested that PHMSA consider the costs to operators of the proposed changes related to facilities outside of HCAs. The OOC also commented that offshore lines present unique challenges that make them ill-fitted for ILI technology and hydrotests.

Other groups and individuals commented on the methods and requirements included in the periodic assessments, inspection intervals, and additional requirements. A 5-year inspection interval was generally favored by citizen groups and individuals, including the Alliance for Great Lakes et al. Congresswoman Capps highlighted that a 3-year interval between inspections had proven to be inadequate to detect corrosion that caused the Plains All American oil pipeline rupture in May 2015. These commenters also requested clarification that alternative methods of assessment must account for inspection along the entire pipeline both inside and outside HCAs and expressed concern with waivers for ILI tools or the use of direct assessment.

The NTSB requested that PHMSA harmonize the gas and liquid regulations to the maximum extent practicable and cautioned that direct assessment is an ineffective alternative technology for IM when applying the 10-year assessment requirement for the integrity of an entire pipeline. They recommended that the IM program encompass a broad range of available

Version Sent to Federal Register

IM technologies including, but not limited to, ILI, magnetic flux leakage, ultrasonic testing, and tests directed at determining the integrity of the pipe coating.

Finally, some citizen groups and individuals requested that inspection reports be made publically available and that operators be required to submit primary inspection results and data to PHMSA. The Environmental Defense Center recommended third-party verification of inspection reports based on corrosion underreporting. These groups also requested risk assessment on non-IM pipelines and annual inspections for all federally regulated hazardous liquid pipelines.

During the February 1, 2016, meeting, the LPAC recommended PHMSA modify the proposed rule to clarify its application to pipelines regulated under § 195.1 that are not subject to the IM requirements in § 195.452. The LPAC also made additional language recommendations to clarify the method of the assessment when ILI tools are impracticable, including pressure tests, external corrosion direct assessment, or other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters. PHMSA notes that the LPAC, with minor tweaks, found the provision for requiring operators to perform these periodic assessments on all covered pipelines not subject to the integrity management requirements under § 195.452 to be a cost-effective, practicable, and technically feasible provision.

However, several commenters noted challenges and cost-benefit concerns with assessing offshore lines and regulated rural gathering lines as a part of this proposal. Issues regarding these

Version Sent to Federal Register

cost concerns were also brought up during a subsequent 12866 meeting between OIRA and API on December 12, 2016. In this final rule, PHMSA is limiting the assessment requirement to onshore, non-HCA, transmission lines that are able to accommodate inline inspection tools.

Under the current regulations, PHMSA notes that approximately 45 percent of hazardous liquid pipelines are required to be assessed per the IM requirements by virtue of being located within an HCA or because they have the ability to affect an HCA. PHMSA has determined that, through this provision, the majority of onshore non-HCA mileage will be assessed at a consistent rate. Further, as pipeline operators continue to replace pipe through modernization projects and repairs, PHMSA assumes that virtually all of the nation's pipeline mileage will be piggable within the next few decades.

In the proposal, PHMSA did not intend for the requirements applicable to lines outside of HCAs to be more stringent than those applicable to lines in HCAs. PHMSA agreed with the commenters and the LPAC that it is appropriate to provide the same flexibility for the assessment of lines outside of HCAs as lines within HCAs, but PHMSA notes that many of these concerns appeared to be in response to PHMSA's requirement to assess all non-HCA lines, even ones that were not readily piggable. As discussed above, the final rule's non-HCA assessment requirement now applies to piggable, onshore transmission line only. The final rule does allow operators to use pressure testing, direct assessment, or other technology in cases when in-line inspections are impracticable. PHMSA has determined that ILI tools may not be available for all pipe diameters and threats being assessed, and providing operators the ability to use these other assessment methods on piggable lines is appropriate at this time.

Version Sent to Federal Register

Further, per the comments received from commenters, including API and Enterprise, related to the use of crack tools, PHMSA has revised the final rule, at both §§ 195.416 and 195.452, to require crack tools only when there is an identified or probable risk or threat supporting their use. For example, if operators have identified a pipeline segment with identified or probable risks or threats related to corrosion and deformation anomalies, including dents, gouges, or grooves, then the operator must assess that segment with a tool capable of detecting those anomalies. Similarly, operators should assess pipeline segments with an identified or probable risk or threat related to cracks using a tool capable of detecting crack anomalies. Essentially, operators should always be selecting an appropriate assessment tool based on the pertinent threats to a given pipeline segment.

Similarly, PHMSA found that the proposed requirements for "discovery of condition" under § 195.416 were more stringent than the revisions proposed for § 195.452. To be consistent with the revised requirements under § 195.452 regarding the discovery of condition, the operator has 180 days to obtain sufficient information on conditions and make the required determinations, unless the operator can demonstrate that the 180-day timeframe is impracticable. In cases where an operator does not have adequate information within 180 days following an assessment, pipeline operators must notify PHMSA and provide an expected date when that information will become available. These revisions will provide consistency for the discovery of condition across all regulated HCA and non-HCA lines.

PHMSA also agreed with the commenters and the LPAC that it is necessary to clarify the pipelines that fall under this section. However, upon further review, PHMSA found that adopting the LPAC-recommended language for § 195.416(a), by clarifying application of this requirement

Version Sent to Federal Register

to pipelines regulated under § 195.1 that are not subject to the IM requirements in § 195.452, would extend this requirement beyond PHMSA's or the LPAC's intent and would cover facilities not previously intended, such as pump stations. Therefore, instead of strictly adopting the language proposed by the LPAC, PHMSA is instead specifying that these requirements apply to onshore, piggable, transmission line pipe not covered under the IM requirements, including the relevant line pipe within pump stations, but not other appurtenances and components like metering stations, tanks, etc. Further, PHMSA is not requiring IM 5-year assessments but is requiring operators to continue the implementation of the preventative and mitigative measures under IM (§ 195.452(i)) for appurtenances, pumps, tanks, etc., for these facilities that could affect a HCA. PHMSA believes this clarification captures the intent of the LPAC members.

In response to the GPA's suggestion for an alternative standard for data analysis, PHMSA's existing process for data analysis has been through a rigorous rulemaking process and has provided an adequate level of safety. PHMSA is not incorporating alternative standards into this rule making that were not included at an earlier rulemaking stage and were not subject to public comment.

Regarding the GPA's other concern as to whether PHMSA provided the LPAC with inaccurate information concerning the extent to which operators are already required to perform assessments on gathering lines versus the new assessment requirements PHMSA was proposing in the NPRM, PHMSA notes that on pages 180 and 181 of the LPAC meeting transcript PHMSA clearly states that it is proposing subjecting currently regulated rural gathering lines to periodic assessment and repair requirements in §§ 195.416 and 195.422, saying, "When it comes to the gathering lines that we don't currently regulate, [that] the regulations don't currently address, the

Version Sent to Federal Register

only requirements we're applying will be the reporting requirements that we discussed prior. In the [NPRM], when it came to regulated rural gathering lines, we proposed to subject them to the assessment requirements in [§ 195.]416 and [§ 195.]422. There's actually a proposal in the NPRM to link the two sections together, but it would not require that lines that are currently, today, not regulated to be assessed." The statement by PHMSA at the LPAC meeting that the GPA questions states that regulated rural gathering lines have an assessment requirement in the NPRM as opposed to currently unregulated gathering lines, which do not. Further discussion and voting at the LPAC meeting indicated that the committee members fully understood PHMSA's proposal, with member Pierson clarifying the definition by asking it to be revised to "transmission and regulated gathering lines" and member Kuprewicz noting "there's clarity with this [definition] now."

With regard to the GPA's other comment on the possibility of the existence of gathering lines in non-rural areas that are not assessed, PHMSA notes this is incorrect. Currently, the only regulated gathering lines that are not subject to assessment requirements are regulated rural gathering lines, which, per their name, are in rural areas. Under existing § 195.1(a)(4), any onshore gathering lines located in non-rural areas and gathering lines located in Gulf of Mexico inlets are covered by 49 CFR part 195, and if these gathering lines are within HCAs or could affect HCAs, they are subject to the full IM program requirements, including integrity assessments, under the current § 195.452. As defined in § 195.2, a "rural area" means "outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, or community development." To exist outside of a "rural area" as that term is defined under § 195.2

Version Sent to Federal Register

(i.e., a "non-rural" pipeline), a pipeline would have to be *inside* (rather than outside) the limits of any incorporated or unincorporated city, town, etc. Per the definition of an HCA at § 195.450, a pipeline in such an area would be in an HCA, and therefore would be regulated and subject to assessment requirements. Therefore, with the exception of regulated rural gathering lines, operators should be assessing all other regulated gathering lines per their IM programs.

PHMSA does not agree with API-AOPL that clarification is needed in the rule on the issue of "idle" pipelines. The Federal PSR list only two statuses a pipeline can be in: in-service/active or "abandoned," which the PSR defines as "permanently removed from service." There is no such thing as an "idle" line. Unless they are abandoned in accordance with applicable procedures, pipelines that are not currently in use must meet all of the requirements of the Federal PSR, including compliance with IM regulations if those pipelines are in HCAs. On March 17, 2014, a disused pipeline leaked crude oil into a highly populated suburb of Los Angeles, CA (Wilmington, CA), releasing an estimated 1,200 gallons of oil.[22] The pipeline was never purged and filled with inert material as per the operator's procedures required by the regulations, and the operator (who bought the pipeline from another operator), believed the pipeline was "abandoned." This demonstrates the fact that pipelines that have been "idled" can still present a safety risk and must be treated as active pipelines. Further, as operators can restart "idle" lines and transport product at a later time, it is important that operators maintain these lines to the same level of safety and standards as an active, in-service line. Accordingly, PHMSA

[22] Jeff Gottlieb: "Phillips 66 oil line in Wilmington blamed for 1,200-gallon spill," Los Angeles Times, March 18, 2014. http://articles.latimes.com/2014/mar/18/local/la-me-0319-crude-oil-20140319

Version Sent to Federal Register

expects operators of “idle” lines to perform assessments and adhere to all of the applicable regulations based on the line’s location.

PHMSA considered the requests it received to make inspection reports for non-HCA lines publically available and to require third-party inspection report verification. PHMSA determined that promulgating those requirements would make assessing non-HCA lines more burdensome than assessing HCA lines.

Regarding requests that PHMSA require non-HCA inspections at 5-year intervals to ensure a larger number of populations and properties are protected, PHMSA notes that setting the non-HCA assessment interval to 5 years would make it equal to that for lines in HCAs. PHMSA determined that this action would shift priority away from HCAs when it comes to risk management and resource allocation, and therefore would actually be a less safe option. Similarly, requiring a yearly inspection of all hazardous liquid pipelines, as some commenters suggested, would be overly burdensome and would work against risk-based prioritization.

Many commenters also requested that PHMSA should require operators perform risk assessments on non-IM pipelines. As discussed in the previous section on extreme weather events, PHMSA expects operators will need to have a certain amount of information on their HCA and non-HCA pipelines in order for them to select the proper tool for an adequate threat analysis. Operators cannot properly perform assessments if they do not know or understand the potential or actual threats to their pipelines. Therefore, PHMSA expects operators will already be performing a level of risk analysis on non-HCA lines as well as HCA lines.

E. *IM and Non-IM Repair Criteria*

Version Sent to Federal Register

1.a PHMSA's Proposal for §195.452 (IM Repairs)

In the NPRM, PHMSA proposed modifying criteria in § 195.452(h) for IM repairs to:

- Categorize bottom-side dents with stress risers, pipe with significant stress corrosion cracking, and pipe with selective seam weld corrosion 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.

1.b PHMSA's Proposal for § 195.422 (non-IM Repairs)

PHMSA also proposed 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.

2. Summary of Public Comment

Citizen groups and individuals expressed concern with the changes to the repair timeline categories. The Alliance for Great Lakes et al. requested that PHMSA maintain the 180-day repair timeframe for all repairs that are not classified as immediate, and the PST did not see justification for the 18-month and "reasonable" time frames added for repairing pipelines outside of HCAs. API-AOPL requested a reasonable timeframe to address repairs in offshore pipelines

Version Sent to Federal Register

that considers the type of repair and permit that might be involved. ETP recommended that PHMSA change the 270-day and 18-month criteria to 1-year and 2-year criteria to assist operators with planning, budgeting, and scheduling.

Enterprise Products Partners suggested specific language to clarify that this section would apply only to pipelines not subject to IM requirements in § 195.452 and those determined not to have the potential to affect HCAs. API-AOPL also expressed concern that PHMSA might apply these criteria beyond non-HCA transmission lines to gravity and gathering lines located offshore and recommended explicit language to state that this section does not apply to gravity or gathering lines. The GPA requested that PHMSA clarify the applicability of this section to out-of-service, idle pipelines.

Commenters also asked for additional standards for conditions triggering repairs. For example, the SCRA requested a more stringent standard for the amount of metal loss that triggers "immediate repair" whereas the Alliance for Great Lakes et al. recommended that PHMSA establish standards for the prevention, detection, and remediation of significant stress corrosion cracking and stress corrosion cracking.

The IPAA commented that PHMSA did not address whether resources exist to make the additional repairs that would be required, nor did it demonstrate a nexus between existing risk and the more conservative repair requirements that justify the potential costs, especially when considering regulated gathering lines. The GPA requested documentation on the basis for requiring the same repair criteria for non-gathering lines as the repair criteria for pipelines affecting HCAs. Western Refining recommended that PHMSA exempt pipeline segments that normally operate at a low pressure from the pressure reduction requirement. API-AOPL

Version Sent to Federal Register

recommended that PHMSA add an immediate repair condition for crack anomalies at a 70 percent nominal wall thickness and an 18-month repair condition on dents with corrosion. API-AOPL also recommended that PHMSA include a "Scheduled Conditions" repair condition for non-HCA lines, which would require an operator to make a report prior to the year when a calculation of the predicted remaining strength of the pipe (including allowances for growth and tool measurement error) shows a predicted burst pressure at less than 1.1 times the MOP at the location of the anomaly. This recommendation aimed to mitigate the potential for pressure-limiting, immediate features before the next ILI. Enterprise Products Partners recommended language to provide operators with flexibility to determine the severity of the reported metal loss indication and its potential impact on the integrity of the pipeline by setting the dent threshold as corroded areas deeper than 20 percent of the nominal wall thickness or where an engineering analysis indicates a reduction in the safe operating pressure of the dented area.

API-AOPL and AGA recommended eliminating the SCC and SSWC immediate repair criteria. The AGA also requested that PHMSA allow pipeline operators to prioritize the repair of HCA segments over non-HCA segments. The GPA was also concerned that PHMSA's definition of SCC was based on the use of the word "significant," because the term is subjective and PHMSA's proposed descriptors do not include all of the variables that influence SCC behavior and is therefore very incomplete for assigning an "actionable" status for all instances.

The PST requested that PHMSA change § 195.563(a) to require that constructed, relocated, replaced, or otherwise changed pipelines must have cathodic protection within 6 months instead of 1 year, and they also requested that PHMSA require operators to know what

Version Sent to Federal Register

type of pipe is in the ground and set the MOP appropriately, or test the pipe with an appropriate hydrotest to demonstrate a safe MOP.

During the meeting of February 1, 2016, the LPAC recommended that PHMSA modify the proposed rule to include recognized industry engineering analysis regarding dents and cracks to determine they are non-injurious and do not require immediate repair, and to give full and equal consideration to the stakeholder comments that were considered during the LPAC discussion.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters. Based on comments from the ANPRM, the NPRM, the LPAC, and from staff experience showing that there are issues with repair decisions based on ILI data, PHMSA is modifying the existing IM repair criteria and establishing time frames for immediate and non-immediate repairs that will provide greater uniformity and include additional conservatism where needed to maintain safety. Some anomalies that previously would not have qualified as immediate conditions will meet this requirement because of the less-than-1.1-times-MOP criteria, which takes into account MOP and surge pressures allowed in 49 CFR part 195. As operators are currently required to repair anomalies once they are discovered, the new timeframes PHMSA is establishing for performing other, non-immediate repairs will allow operators to remedy those conditions in a timely manner while prioritizing resources to those anomalies that present a higher safety risk to the public, property, and the environment. Operators currently make repairs to address safety and integrity conditions of pipelines in HCAs and those in non-HCAs. The final rule is not expected to affect

Version Sent to Federal Register

the total number of repairs to address safety or integrity conditions, but the timing of these repairs may change. PHMSA expects the net effects on costs or benefits to be small and to include some cost savings from consolidating requirements under one category.

PHMSA notes that the LPAC, with certain suggestions, found the non-HCA repair criteria to be cost-effective, practicable, and technically feasible provisions. However, following a subsequent 12866 meeting between OIRA and API on December 12, 2016, PHMSA could not provide detailed cost-benefit information necessary to support promulgating the proposed changes at this time and is retaining the existing non-IM repair language at § 195.401(b)(1).

API-AOPL suggested several revisions to PHMSA's proposed repair criteria, including suggesting that PHMSA should expand appropriate calculation methods for crack anomalies or SSWC associated with electric flash welded (EFW) and ERW seams to include alternative methods. PHMSA notes that these regulatory requirements for immediate repair conditions for cracking allow for the calculation of the remaining strength of pipe using methods other than those presently specified in the regulations; calculations using the Battelle Model (Modified Log-Secant), CorLAS™, the Pipe Axial Flaw Failure Criteria (PAFFC), and other conservative evaluation methods, as appropriate for the threat or anomaly, are acceptable for crack evaluation when operators use the proper material properties, environmental conditions, operational parameters (including pressure cycling), and conservative safety factors based on the accuracy of the technical evaluation method. Operators would be required to justify and document the usage of other technical evaluation methods.

API-AOPL and members of the LPAC also suggested that, for several proposed repair criteria, PHMSA should allow operators to use an ECA analysis to determine whether an

Version Sent to Federal Register

anomaly is injurious or non-injurious and whether operators need to take further action. PHMSA considered the comments from API-AOPL and the LPAC and determined that allowing operators to use ECAs in determining whether certain crack anomalies are injurious and whether operators could extend repair timeframes would provide operators with some additional flexibility with regard to performing those repairs while maintaining a high standard of safety. Defining the ECA performance requirements in the regulations will help ensure consistency in how operators perform these assessments for crack defects. PHMSA is also providing operators with the flexibility to use "other technology" (other than what is specifically provided in the regulatory text) to perform these ECAs, if that technology can provide an equivalent understanding of the condition of the line pipe. Prior to conducting ECAs with "other technology," operators must receive a notice of "no objection" from PHMSA. PHMSA retains its discretion to rescind notices of "no objection" should technical reviews show the "other technology" is ineffective.

PHMSA considered developing regulatory requirements for using an ECA for dents classified in the immediate repair category and evaluated research on the topic from a PHMSA-sponsored research project conducted by BMT Fleet Technology titled "Dent Fatigue Life Assessment" (January 10, 2012; DOT—DTPH56-10-T-000013).[23] The study examined four fatigue life assessment methodologies (API 1156 (Alexander), EPRG, Rosenfeld, and Fowler) in Table A.7 ("Estimated and Experimental Fatigue Lives for MD4-2 Specimens"), Table A-8

[23] BMT Fleet Technology Limited: "Dent Fatigue Life Assessment;" DOT #432, Closeout Report; DTPH56-10-T-000013; January 10, 2012.
http://ntl.bts.gov/lib/46000/46200/46286/FilGet.pdf

Version Sent to Federal Register

("Estimated and Experimental Fatigue Lives for Additional Specimens"), and Figure A.2 ("Comparison of Estimated and Experimental Fatigue Lives"). The study found "there was a significant amount of scatter between the predicted and experimental fatigue life with some of the methodologies greatly overestimating and others under estimating the fatigue life." Based on this research, PHMSA determined that none of these methods would be able to evaluate all of the integrity threats in an appropriately conservative manner. As PHMSA is not aware of dependable evaluation methods for dents with metal loss, cracking, or stress risers, PHMSA is not allowing operators to perform ECAs for dent anomalies at this time. PHMSA intends to conduct further research to consider ECA of dents on a global basis.

PHMSA defined an immediate repair condition for any indication of significant SCC, which PHMSA is defining in § 195.2 as an SCC cluster in which the deepest crack, in a series of interacting cracks, is greater than 10 percent of the wall thickness, and the total interacting length of the cracks is equal to or greater than 75 percent of the critical length of a 50 percent through-wall flaw that would fail at a stress level of 110 percent of SMYS. Significant SCC has a similar definition in NACE SP0204-2008.[24] PHMSA also defined an immediate repair condition for any indication of SSWC associated with lap-welded pipe and EFW and ERW seams with historical

[24] "An SCC cluster was defined to be significant by the Canadian Energy Pipeline Association (CEPA) in 1997 provided that 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. CEPA also defines the interaction criteria. The presence of extensive and significant SCC typically triggers an SCC mitigation program, but a crack that is labeled 'significant' is not necessarily an immediate threat to the integrity of the pipeline."
NACE International: "Stress Corrosion Cracking (SCC) Direct Assessment Methodology," Standard Practice, SP0204-2008 (formerly RP0204), Approved September 18, 2008.
http://www.nace.org/uploadedFiles/Committees/SP020408.pdf

Version Sent to Federal Register

seam integrity risks known from manufacturing processes or in-service leaks or failures. Alternatively, PHMSA is allowing operators to use an ECA for significant SCC and SSWC evaluations, based on fracture mechanics principles and finite element analysis techniques, that considers, at a minimum, factors including flaw size, material properties, stress, strain, MOP, pressure cycling, and flaw growth to determine the maximum tolerable flaw sizes for imperfections in steel pipe. Operators must determine failure pressures based on the use of technically accepted fracture mechanics evaluation methods for assessing axial flaws and failure modes such as: Modified Log-secant, CorLas^{TM}, PAFFC, or other technically proven evaluation methods and through using either known or conservative pipe mechanical properties to determine a predicted burst pressure. If not remediating in accordance with § 195.452(h)(4)(i)(E), an operator can use an alternative evaluation approach that includes ECA and repair any significant SCC or SSWC defects that the ECA finds are less than 60 percent of pipe wall thickness for non-HCAs and less than 50 percent of pipe wall thickness for HCAs and could-affect HCAs. Additional evaluation measures in the ECA criteria are based on MOP and pipe mechanical properties (100 percent of the specified minimum yield strength or 1.39 times maximum operating pressure). In crack defect assessment situations, including stress corrosion cracking or selective seam weld corrosion, operators are expected to evaluate if more conservative criteria of up to 110 percent of specified minimum yield strength (or up to 1.53 times maximum operating pressure) should be used for the engineering critical assessment based on criteria such as mechanical properties, operational conditions, seam type, crack type, and crack defect sizing.

Version Sent to Federal Register

PHMSA took technical guidance information from several sources into account regarding significant SCC and SSWC when creating alternative, non-mandatory (alternative ECA) repair criteria for these anomalies. Specifically, PHMSA considered ASME ST-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas;"[25] the PRCI-PR 3-9523 Phases One and Two report titled "Evaluation of Hydrotest Requirements and Alternatives to Hydrotesting" (2001) by Brian Leis,[26] Battelle's "Comprehensive Study to Understand Longitudinal ERW Seam Failures;"[27] Kiefner and Associates, Inc.'s report on "Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue;"[28] Battelle's report on "Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications;"[29] Kiefner and Associates, Inc.'s report on "Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams;"[30] Kiefner and

[25] ASME Standards Technology, LLC: "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas," STP-PT-011, October 31, 2008.
[26] Leis, Brian: "Hydrostatic Testing of Transmission Pipelines: When It Is Beneficial and Alternatives When It Is Not;" Program PR 3-9523 Phases One and Two, "Evaluation of Hydrotest Requirements and Alternatives to Hydrotesting;" 2001.
[27] Battelle Memorial Institute: "Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures – Phase One," DTPH56-11-T-000003, October 23, 2013. https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=8501
[28] Kiefner and Associates, Inc.: "Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue," Final Report No. 13-021, DTPH56-11-T-00003, January 28, 2013. https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=7929
[29] Battelle Memorial Institute: "Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications," Final Interim Report – Task 1.4, DTPH56-11-T-000003, September 20, 2012. https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=7885
[30] Kiefner and Associates, Inc.: "Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams (with an addendum by Brian Leis presenting Battelle's experience with the PAFFC model)," Final Report No. 13-002, DTPH56-11-T-000003, January 3, 2013. https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=7917

Version Sent to Federal Register

Associates, Inc.'s report titled "Repair/Replace Considerations for Pre-Regulation Pipelines;"[31] the Michael Baker Jr., Inc. report titled "Spike Hydrostatic Test Evaluation;"[32] and NACE Standard Practice SP0204-2008, "Stress Corrosion Cracking Direct Assessment," approved September 18, 2008.

Time-dependent crack growth can also occur due to fatigue from environmental and operational conditions, including pressure cycling. To address crack growth, whether by static or cyclic loading, that might occur during the time between reassessment intervals, operators must consider a field-derived maximum growth rate that accounts for the pipeline's specific operating conditions, including changes during the interval prior to the next assessment interval, mechanical properties, pressure cycling, and operating environment.

When operators find cracks after excavations or ILI runs, they must establish how severe those cracks are in order to determine what mitigative actions to take and how quickly those actions should be taken. The evaluation methods PHMSA proposed for the failure pressures of axial flaws are based on historical methods documented in ASME ST-PT-011, the PRCI report, and the other reports listed above. This research has noted that using a particular method could produce different results based on the depth and length of the cracks as well as the pipe's material properties. Operators will need to incorporate these variables into their overall calculations in a satisfactorily conservative manner.

[31] Kiefner and Associates, Inc.: "Repair/Replace Considerations for Pre-Regulation Pipelines," Final Report No. 15-019, DTPH5614H00006, March 11, 2015.
https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=9427
[32] Michael Baker Jr., Inc.: "Spike Hydrostatic Test Evaluation," Final Report, OPS TT06 , July 2004.
https://primis.phmsa.dot.gov/iim/docstr/TTO6_SpikeHydrostaticTestEvaluation_FinalReport_July2004.pdf

Version Sent to Federal Register

ASME ST-PT-011 states that stress corrosion cracks are “Noteworthy” (which is similar to the “significant stress corrosion cracking” definition in this rule) if the maximum crack depth is greater than 10 percent of the wall thickness and if the maximum interacting crack length is more than the critical length of a 50 percent through-wall crack at a stress level of 110 percent SMYS and provides categories as follows:

Category 1: Predicted Failure Pressure (PFP) is above 110 percent SMYS (note that 110 percent SMYS is used to delineate Category 1 cracks because it corresponds to the pressure most commonly prescribed for hydrostatic testing)

Category 2: PFP is above 125 percent MAOP and below 110 percent SMYS

Category 3: PFP is above 110 percent MAOP and below 125 percent MAOP

Category 4: PFP is below 110 percent MAOP

Category Zero: A crack below the threshold for Noteworthy cracks. These typically fall into two groups: 1) Those that are shallow (i.e., less than 10 percent through-wall depth), or 2) Those that are so short that, even if they were 50 percent through-wall depth, they would not result in a hydrostatic test failure. In § 195.452, ECAs are allowed using a combination of Categories 1 through 3 described above. Any Category 4 cracking defect below 110 percent maximum operating pressure would require immediate remediation.

These severity categories allow operators to estimate the minimum remaining life at operating pressure for each category. The following estimates from ASME ST-PT-011 are based on the time it would take for the crack depth to increase to a failure-causing depth at the operating pressure. For pipelines operating at 72 percent SMYS, the following minimum operational lives for each category of cracks are as follows:

Version sent to Federal Register

Category Zero: Failure life exceeds 15 years (for short cracks) to 25 years (for shallow cracks)

Category 1: Failure life exceeds 10 years

Category 2: Failure life exceeds 5 years

Category 3: Failure life exceeds 2 years

Category 4: Failure may be imminent

ASME ST-PT-011 further states that mitigating a pipeline segment with SCC should be commensurate with the severity of the discovered crack, which would reflect the PFP and the estimated life at the operating pressure. For example, Category Zero cracks may warrant no more than ongoing SCC condition monitoring and reassessment after a period of 7 years. Cracks may be best addressed by direct assessment, hydrostatic testing, or ILI. The most severe cases would require an immediate pressure reduction, repair (if the location is known), and hydrostatic testing or ILI, followed by the appropriate mitigation measures.

Hydrostatic testing has proven to be an effective way of managing SCC in buried pipelines. From a technical perspective, and according to the Leis and Kurth final report titled "Hydrotest Parameters to Help Control High-pH SCC on Gas Transmission Pipelines," the optimal procedure for a hydrostatic test involves a short pressure spike at a relatively high pressure, followed by a leak test. The spike pressure should be as high as possible within the range of 100 to 110 percent SMYS (1.39 to 1.53 times MOP) based on the defect being assessed and the mechanical properties of the pipe but should not be so high as to cause the pipe to bulge or cause small, stable weld defects to fail. These values are based on an assumption that the pipeline being tested is designed to operate at a hoop stress level equal to 72 percent of SMYS.

Version Sent to Federal Register

ASME ST-PT-011 notes in “The Spike Test” section that where a 110 percent SMYS spike test is impractical because of pipeline elevation differences, a 105 percent SMYS spike test is nearly as good, and a 100 percent spike test offers considerable benefit. ASME ST-PT-011 notes that a 90 to 95 percent spike test provides little benefit for crack evaluation.

Research has indicated that 10 minutes to 1 hour is an appropriate amount of time for operators to hold a spike test pressure. This philosophy is especially apparent in ASME B31.8S, which specifies a 10-minute hold time when testing for SCC. However, as the Baker report suggests, “the length of hold time has no discernible impact on the effectiveness of a hydrostatic test in establishing an adequate safety margin. The most important consideration is attaining the highest possible test pressure even if only for a few minutes.”

Battelle’s report on ERW and flash-weld seam defects discovered that, for larger defects, fabrication-related defect origins fail at higher pressures relative to origins that trace to selective seam corrosion (SSC). To effectively remove some of these types of defects that pose a threat to integrity, operators must hydrotest to a minimum pressure of 100 to 110 percent SMYS or employ spike hydrostatic pressure tests to minimize growth of the remaining defect population. While hydrotesting to a minimum pressure of 110 percent SMYS exposes 98 percent of defects according to the Battelle report, pressure testing to that level can be impractical due to elevation changes or other factors. However, testing at reduced pressures could allow more defects to remain in the line, and holding lower pressures with longer holds can lead to stable tearing of larger defects, which could lead to pressure reversals. As such, operators must broadly understand the causes of defects likely present in their pipelines as well as defect responses to previous hydrostatic testing.

Version Sent to Federal Register

Kiefner's report on repair/replace considerations for pre-regulation pipelines explained that models for predicting failure stress levels of ERW seam defects must take into account whether the failure is in ductile or brittle material. Several fracture mechanic models exist for predicting the failure stress of axially oriented, partially through the wall defects in pressurized pipe, including PAFFC, CorLas^{TM}, API 579 – Level II, the Modified Ln-Sec Model, and the Newman/Raju Model. Defects in most line pipe materials tend to fail in a ductile manner. Exceptions include defects in the longitudinal weld bond line of low frequency electric resistance welded (LF-ERW), direct-current electric resistance welded (DC-ERW), or flash-welded pipe material. These may fail as a brittle fracture.

Kiefner's reports on models for predicting failure stress levels of ERW seam defects and repair/replace considerations for pre-regulation pipelines stated that operators should apply a factor of safety to calculated times (growth rate) to failure for any defects that might remain after hydrostatic tests or for those discovered through ILI inspections. According to the Kiefner report, applying a safety factor of 2 (a 50 percent reduction) to the calculated time to failure for defects that could have barely survived a hydrostatic test is appropriate. Further, applying a safety factor of 2 to the calculated time to failure for defects identified by ILI is appropriate if inspection tool error is accounted for in an appropriate technical manner to maintain safety. This safety factor of 2 means that an operator should respond to the given anomaly by the time half the time to failure has expired.

Further, calculated times to failure after hydrostatic tests increase exponentially when test pressures and operating pressures are at a high ratio. Operators can maximize the length of time between reassessments by using the highest feasible test pressure possible. Higher, appropriate

Version Sent to Federal Register

test pressures will typically yield smaller remaining defects, which will result in longer times to the next assessment interval.

The NACE SP0204 standard for stress corrosion cracking (SCC) direct assessment incorporated the “Significant SCC” definition from the Canadian Energy Pipeline Association (CEPA), defining the term as “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 the specified minimum yield strength (SMYS). The presence of extensive and significant SCC typically triggers an SCC mitigation program, but a crack labeled “significant” is not necessarily an immediate threat to the integrity of the pipeline.” The 49 CFR part 195 definition of “Significant SCC” established in this rule is similar to the NACE and CEPA definitions.

The PST’s comments relating to cathodic protection is beyond the scope of topics covered by the proposed rule, and cannot be adopted by PHMSA. Regarding the PST’s request for PHMSA to require operators to determine a safe MOP, PHMSA notes that the requested requirements are more stringent than those proposed by the NPRM, and are therefore considered out of scope. PHMSA is also addressing this topic in other ways—on August 27, 2015, PHMSA hosted a public workshop to focus on the concept of "Hazard Liquid Integrity Verification Process (HL IVP)." The HL IVP is to confirm the MOP when pipeline records are not traceable, verifiable, or complete. PHMSA presented the latest information for a proposal for HL IVP and has presentations of perspectives from pipeline operators, state regulatory partners, and the public. PHMSA held a similar workshop in August 2013 on the Integrity Verification Process for

Version Sent to Federal Register

gas transmission pipelines to help address several mandates in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and NTSB recommendations.

F. *Leak Detection requirements*

1. PHMSA's Proposal

With respect to new hazardous liquid pipelines, PHMSA proposed to amend § 195.134 to require that all new lines be designed to have leak detection systems, including pipelines located in non-HCA areas.

With respect to existing pipelines, 49 CFR part 195 contains mandatory leak detection requirements for only those 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. Congress authorized the issuance of regulations for leak detection if warranted by the findings of the report.

Based on information available to PHMSA including post-accident reviews and the Kiefner Report, PHMSA believes the need to strengthen the requirements for leak detection systems is clear. In addition to modifying § 195.444 to require a means for detecting leaks on all portions of a hazardous liquid pipeline system including non-HCA areas, PHMSA proposed that operators perform an evaluation to determine what kinds of systems must be installed to

Version Sent to Federal Register

adequately protect the public, property, and the environment. The proposed amendment to § 195.11 extended these new leak detection requirements to regulated onshore gathering lines.

2. Summary of Public Comment

Trade organizations expressed concerns with requiring operators of gathering lines and certain non-gathering lines to install and maintain leak detection systems. The GPA commented that PHMSA's proposal is not appropriate for gathering lines at this time, citing findings of the "Liquids Gathering Pipelines: A Comprehensive Analysis" study, which concluded that 1) gathering lines present unique challenges to leak detection technologies; 2) gathering lines are constantly transition in flow, pressure, and line-packing; 3) benefits do not justify the cost for leak detection systems applied to gathering lines; and 4) there is a lack of demonstrated technology to reliably detect spills (Energy & Environmental Research Center, 2015). IPAA noted that PHMSA should not proceed with expanding leak detection systems because it had not performed an analysis of the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems. The GPA also recommended that PHMSA provide relief for short sections of pipeline less than 1 mile in length and lines located within facilities where they pose no risk to the public. API-AOPL and OOC requested clarification that this section would not apply to offshore gathering lines. The commenters requested implementation periods ranging between 5 years (API-AOPL) and seven years (GPA). Finally, the Texas Pipeline Association commented on the cost of

Version Sent to Federal Register

complying with this regulation for lines outside of HCAs and the redirection of resources from high-risk areas to lower-risk areas.

Citizen groups and other commenters requested minimum standards for leak detection systems, and applicability to all hazardous liquids lines. The Pipeline Safety Coalition recommended the inclusion of 1) all existing hazardous liquids lines and all lines under construction at rulemaking; 2) prescriptive standards for leak detection classifications; 3) prescriptive standards for acceptable leak detection procedures and devices; and 4) standards that are specific to location, community, and environmentally sensitive areas. The Alliance for Great Lakes et al. commented that computational pipeline monitoring systems detect only large ruptures and involve significant data interpretation and analysis. They expressed concerns regarding the lack of system standards and guidance on how to assess the effectiveness of a given leak detection system on a given pipeline due to significant variations in pipeline design. The Environmental Defense Center also recommended that automatic shutdown systems be required.

Beyond requirements for new pipelines, some commenters also requested a clear schedule for leak detection system for pipelines undergoing construction. For example, the NTSB urged PHMSA to include language that specifies a distinct trigger date for leak detection implementation on pipelines that have already started construction but would not yet be operational when the new regulation becomes effective.

During the February 1, 2016, meeting, the LPAC recommended that PHMSA modify the proposed rule to 1) provide a 5-year implementation period for existing pipelines and a 1-year

Version Sent to Federal Register

implementation period for new pipelines and 2) clarify that the expanded use of leak detection systems is not applicable to offshore gathering pipelines.

3. PHMSA Response

PHMSA notes that commenters asserting PHMSA lacks the authority to require leak detection systems because it did not first conduct a study of these systems are incorrect. PHMSA did perform a leak detection study ("Leak Detection Study—DTPH56-11-D000001"[33]), as required by section 8 of the 2011 Pipeline Safety Act, and submitted this study to Congress on December 31, 2012. The study examined what methods and measures operators were using as leak detection systems and the limitations of those methods and measures. The study noted that "due to the vast mileage of pipelines throughout the nation, it is important that dependable leak detection systems are used to promptly identify when a leak has occurred so that appropriate response actions are initiated quickly. The swiftness of these actions can help reduce the consequences of accidents or incidents to the public, environment, and property." The study also noted that "incidents described as leaks can also have reported large release volumes." Based on the results of the study, and due to pipeline incidents such as those near Marshall, MI, and Salt Lake City, UT, which the study referenced, PHMSA concluded that operators need to have an adequate means for identifying leaks to better protect the public, property, and the environment.

[33] Kiefner & Associates, Inc.: "Leak Detection Study," Final Report No. 12-173, DTPH56-11-D-000001, December 10, 2012. http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Press%20Release%20Files/Leak%20Detection%20Study.pdf

Version Sent to Federal Register

PHMSA continues to foster leak detection technology improvements through research and development projects, and PHMSA is also considering pursuing rupture detection metrics through another rulemaking activity.

Recognizing that leak detection technology can be unreliable does not imply that monitoring and leak detection are without value. The value of lost product, negative impacts to the environment, loss of pipeline functionality, spill remediation costs, and public perception all impact decisions regarding the implementation of leak detection systems. As pipeline leaks are generally unpredictable, it is difficult to assign costs to many of these items. Other factors, such as public perception, cannot be evaluated on an economic basis. PHMSA expects that the implementation of leak detection systems on non-HCA pipelines will accelerate leak detection, lead to faster response and spill containment, and reduce damages from hazardous liquid releases.

Given this information, PHMSA is finalizing a rule that requires all new and existing lines, with the exception of gathering lines not subject to IM, to implement leak detection systems. Since all lines within HCAs are already subject to this requirement, the final rule affects transmission pipelines outside of HCAs.

Commenters and LPAC members made persuasive arguments regarding the technical challenges that exist for implementing leak detection systems on offshore gathering lines due to the complex network of gathering lines coming from offshore platforms and tremendous fluctuations in flow controlled directly by production platforms. Further, commenters had concerns that there was not adequate justification for leak detection requirements on regulated rural gathering lines due to the lack of incident history. Therefore, PHMSA is not extending leak

Version Sent to Federal Register

detection requirements to offshore gathering lines or regulated rural gathering lines at this time. However, PHMSA does note that the LPAC had no objections to extending this requirement to regulated rural gathering lines and found the provision to be a cost-effective, practicable, and technically feasible provision. Further, during the 12866 meeting between OIRA and API on December 12, 2016, API presented data stating that operators agree with PHMSA's assumptions regarding the use of leak detection systems on non-HCA pipelines.[34]

PHMSA considered input from the comments and from the LPAC in setting compliance periods of 1 year for all new lines, and 5 years for all existing lines. Regarding concerns about compliance periods for pipelines under construction, PHMSA asserts that any line that becomes operational after the publication of this rule is a new line and will have 1 year to comply. PHMSA will consider pipelines that are already operational before the publication of this rule as existing lines, and those will have 5 years to comply. PHMSA determined that the specified timelines are reasonable and practicable given that many operators already implement leak detection systems on their entire network across both HCA and non-HCA miles, and because many operators are constructing and designing new lines with leak detection system capabilities. Further, PHMSA assumes that the cost of extending existing capabilities to non-HCA miles is minimal for systems already equipped with SCADA sensors (see Section 3.6 in RIA for details).

Certain commenters questioned the methods of leak detection that PHMSA would require to comply with this provision. PHMSA notes that negative pressure wave monitoring, real-time transient modelling, or other external systems are not necessarily required to comply with the

[34] https://www.regulations.gov/document?D=PHMSA-2010-0229-0132

Version Sent to Federal Register

rule. The costs of using or installing these leak detection system components were not explicitly analyzed in the RIA; however, operators may voluntarily choose to use these components, as well as any others, in order to comply with the leak detection requirements of the rule.

PHMSA received several comments regarding leak detection system performance criteria, valve spacing requirements, and automatic shutdown capability, which were topics listed in the ANPRM. Due to the complexity of these topics and the need for further study and public comment, PHMSA is pursuing these topics in a separate rulemaking.

G. *Increased Use of In-line Inspection Tools (ILI) in HCA Areas*

1. PHMSA's Proposal

PHMSA proposed to require that all hazardous liquid pipelines in HCAs 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 be designed to accommodate in-line inspection tools. 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.

2. Summary of Public Comment

Trade organizations expressed concern that the proposed rule would inhibit operators from exercising their expert judgement in selecting an assessment method and would be overly

Version Sent to Federal Register

burdensome. API-AOPL and other industry representatives requested that PHMSA not adopt this proposal because it would require pipelines to incur extensive costs due to age, design, and location of the pipelines, without demonstrating commensurate benefits. They also requested that PHMSA remove the requirement to petition for an exemption under § 190.9 and instead continue to allow operators to exercise their expertise and engineering judgment in using the most effective and efficient methods of evaluating the integrity of their facilities with prior notification to OPS.

The IPAA and AGA requested that PHMSA review current studies or conduct an original study to determine if ILI is appropriate to monitor pipeline corrosion given the current state of technology. The AGA also requested that PHMSA provide additional information on what the term "basic construction" meant in the exemption from the ILI-capable requirement. The IPAA requested that PHMSA implement performance standards instead of expanding the use of ILI tools.

Conversely, citizen groups and individuals recommended that operators use ILI more broadly. The SCRA and others expressed concern with the length of the 20-year implementation period and the multiple exemptions such as where the pipe is constructed in such a way that an ILI device cannot be accommodated. Specifically, the SCRA recommended instead that 1) PHMSA significantly reduce the timing of accommodating ILI devices, perhaps to 5 years; 2) PHMSA require all new pipelines constructed in HCAs to accommodate ILI devices immediately; 3) PHMSA reexamine and tighten proposed exemptions; and 4) PHMSA establish standards for ILI tools, including the detection of stress corrosion cracking. Congresswoman Capps suggested that PHMSA could establish a shorter time frame of 5 years with an extension

Version Sent to Federal Register

possible upon request with sufficient evidence for need and a provided plan of action to meet the standard. The PST recommended that operators integrate Close Interval Survey results into ILI device findings.

Other groups commented on the tools used for inspection, the compliance periods, and accountability. The Environmental Defense Center requested that PHMSA require other inspection tools and methods, such as hydrostatic pressure testing, where operators detect certain types of anomalies and when these technologies can provide additional information regarding the condition and vulnerabilities of a pipeline system. The Alliance for Great Lakes et al. recommended that PHMSA develop a framework that assigns different compliance periods for pipelines based on factors such as age, leak history, corrosion, environmental circumstances that could affect the pipeline, and other aspects such as those typically reviewed in IM studies. Finally, California Assembly Member Das Williams requested that operators be required to submit ILI data to PHMSA for review and verification.

The NTSB recommended that PHMSA require owners/operators to develop comprehensive implementation plans with transparent progress reporting of intermediate milestones to best ensure operators modify existing pipelines to accommodate the passage of ILI devices within the 20-year time limit. The NTSB also recommended that operators modify all newly identified HCA segments to accommodate an internal inspection tool according to an accelerated schedule, but not more than 5 years after an operator identifies the HCA.

During the February 1, 2016, meeting, the LPAC recommended that PHMSA adopt the proposed 20-year implementation period as feasible and cost-effective. In a separate vote, the LPAC reached a tie on a 10-year implementation period, which resulted in a failed motion. The

Version Sent to Federal Register

LPAC also recommended that § 195.452(n) be modified to allow an operator to file a petition that ILI tools cannot be accommodated when the operator determines it would abandon or shut down a pipeline as a result of the cost to comply.

3. PHMSA Response

PHMSA carefully considered input from commenters and the LPAC in finalizing this rule, which requires that all HCA pipelines whose basic construction would accommodate ILI tools be modified to permit the use of ILI tools within 20 years. Examples of "basic construction" that an operator may be able to show would not accommodate ILI tools include short length, small diameter, diameter changes, low operating pressure, low-volume flow, location, sharp bends, and terrain. PHMSA shares the interest of commenters who requested expeditious upgrades to the pipeline network to accommodate ILI tools. PHMSA maintains that ILI tools are generally more effective than other methods at detecting integrity issues. ILI tools take advantage of state-of-the-art technological developments and allow operators to identify anomalies and prioritize anomalies without interrupting services. ILI tools also provide a higher level of detail than is possible using other testing tools such as hydrotesting, which allow operators to determine whether a required safety margin is met (i.e., pass/fail) but do not provide information about the existence of anomalies that could deteriorate over time between tests. PHMSA notes that the existing regulation already requires new pipelines to be capable of accommodating ILI tools, as certain commenters requested. Data from operators' annual reports suggest that the vast majority of pipeline miles are currently assessed using ILI tools. The mileage not assessed using these tools is likely to consist of pipeline segments, such as small

Version Sent to Federal Register

diameter pipes, where ILI is impracticable using the current technologies. Providing sufficient time for ILI tool accommodation projects allows the industry to prioritize these projects based on age or other factors, including the risk factors identified by the Alliance for the Great Lakes in their comments; it also reduces the mileage of pipeline potentially needing to be replaced before they have reached their operational life. PHMSA determined that a 20-year timeline strikes the appropriate balance between the need to make upgrades as soon as possible to enable more effective integrity assessment technologies, with the costs and operational practicalities of making those changes. Given that a preponderance of HCA pipelines can already accommodate ILI tools, exceptions available for specific pipeline designs, operational benefits of ILI over other assessment methods, the continued aging of unpiggable lines, and the 20-year compliance deadline that will further reduce remaining mileage of old pre-ILI pipeline, PHMSA determined that the final rule requirement to make existing HCA pipelines able to accommodate ILI tools is unlikely to impact any amount of the hazardous liquid pipeline infrastructure. Accordingly, PHMSA does not estimate any cost for this requirement.

To help ensure that operators make reasonable progress in installing ILI launchers and receivers where needed, PHMSA will consider modifying its annual report form to have hazardous liquid pipeline operators report data on what percentages of their lines are piggable. In response to commenters who sought more immediate implementation, PHMSA notes that inability to use ILI on a pipeline segment does not mean that an operator has not assessed the pipeline; the regulation requires that these pipelines be assessed using alternative approaches, with hydrotesting being the most common alternative. Data reviewed by PHMSA indicates that

Version Sent to Federal Register

less than 1 percent of HCA pipeline mileage is assessed using direct assessment methods. Comments about seismicity considerations are addressed in the next section.

In response to commenters who requested a specific deadline for making lines in newly identified HCAs capable of accommodating ILI tools, PHMSA notes that operators will have until the end of the 20-year implementation period to make lines piggable. Operators who newly identify HCAs in years 16-20 of the implementation period and after the 20-year implementation period will have 5 years from the date of the HCA identification to make lines in those areas piggable.

H. *Clarifying other requirements*

1. PHMSA's Proposal

PHMSA also proposed several other clarifying changes to the regulations that were intended to improve compliance. First, PHMSA proposed to revise paragraph (b)(1) of § 195.452 to better harmonize the current regulations. The existing § 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 1 year after the pipeline begins operation. Improved consistency would be beneficial, as the identification of could affect segments and the performance of baseline assessments are elements of the written IM program. PHMSA proposed to amend the table in (b)(1) to resolve this inconsistency by eliminating the 1-

Version Sent to Federal Register

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.

PHMSA proposed to add additional specificity to 195.452(g) by establishing a number of pipeline attributes that must be included in IM information analyses and to require explicitly that operators integrate analyzed information to help ensure they are properly evaluating interacting threats. PHMSA also proposed that operators consider explicitly any spatial relationships among anomalous information.

PHMSA also proposed that operators verify their segment identification annually by determining whether factors considered in their analysis have changed. The change that PHMSA proposed would not require that operators automatically 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 segment analysis to validate or change the endpoints of the segments affected by the change.

PHMSA also proposed to add an explicit reference clarifying that the IM requirements apply to portions of pipeline facilities 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. While most operators correctly treat any component that product moves through in areas that could affect HCAs as subject to IM, PHMSA has reason to believe that some operators have not

Version Sent to Federal Register

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 proposed 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.

2. Summary of Public Comment

Trade organizations commented primarily on the implementation period for PHMSA's clarifications on data integration and the attributes and information required. Other trade associations joined API-AOPL in requesting a 5-year implementation schedule for integrating these specific attributes, including populating data into information systems and validating the quality of the data process. The AGA recommended that PHMSA focus on the *analysis* of information and attributes rather than their *integration*.

Trade organizations also requested flexibility in developing the attributes and information required in data analysis. The AGA requested that operators independently develop the list of information and attributes to be included in data analysis. They also commented that there is no

Version Sent to Federal Register

current regulatory requirement for an operator of hazardous liquid or natural gas pipelines to maintain or utilize a GIS.

Finally, trade organizations expressed concern with changes to the baseline assessment of newly constructed pipelines. API-AOPL requested that PHMSA clarify that hydrostatic testing is an acceptable method of meeting this requirement for new construction.

During the February 1, 2016, meeting, the LPAC recommended that PHMSA modify the proposed rule to require data integration to begin in year one, with all attributes completed within 3 years.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters. As discussed at the LPAC meeting, integrating data is a key element and concept of continuous improvement and IM. The requirement that operators perform data integration has long been a part of IM program requirements. The attributes that PHMSA proposed in the NPRM were factors operators should have already been considering when assessing risk to their pipelines—PHMSA is merely codifying them to better ensure all operators are utilizing them. PHMSA understands that the need for some operators to enhance their data systems to fit these specific attributes will take some time and effort. Because of this, PHMSA agrees with the LPAC that operators should be given a maximum of 3 years to fully comply and integrate all of the proposed attributes into their data integration systems, with implementation beginning once the rule is published. However, this implementation period does not mean operators should lapse in what they are currently required to perform under § 195.452(g). PHMSA expects operators to add the attributes issued in

Version Sent to Federal Register

this final rule to their current data integration systems and efforts. While PHMSA is sympathetic to allowing operators more flexibility with the attributes that should be considered for data integration, past experience has shown that PHMSA needs to prescribe a common baseline set of attributes for operators to consider.

PHMSA agrees with commenters who believe hydrostatic testing is an acceptable baseline assessment method for newly constructed pipelines and is incorporating that option into this final rule. As operators are required to conduct hydrostatic tests on all newly constructed pipelines prior to operation, and PHMSA allows operators to use hydrostatic testing for subsequent assessments, PHMSA has determined this could eliminate additional duplicative baseline assessments and reduce operator burden.

V. PIPES Act of 2016

On June 22, 2016, the President signed the PIPES Act, Public Law No. 114-183, containing Sections 14 and 25, "Safety Data Sheets" and "Requirements for Certain Hazardous Liquid Pipeline Facilities," respectively. The language in both Section 14 and Section 25 is self-executing, with Section 25 specifically amending the Pipeline Safety Act at 49 U.S.C. § 60109 by adding new paragraphs (g) through (g)(4). In order to allow the timely implementation of these sections of the PIPES Act of 2016 and to help ensure regulatory certainty, PHMSA has determined that good cause exists for finding that notice and comment on these provisions is impracticable and contrary to the public interest and is subsequently incorporating them into this final rule.

Version Sent to Federal Register

Section 14 of the PIPES Act requires owners and operators of hazardous liquid pipeline facilities, following accidents involving pipeline facilities that result in hazardous liquid spills and within 6 hours of a telephonic or electronic notice of the accident to the National Response Center, to provide safety data sheets on any spilled hazardous liquid to the designated Federal On-Scene Coordinator and appropriate State and local emergency responders. PHMSA has incorporated this requirement in a new § 195.65 under the reporting requirements of Subpart B.

Section 25 of the PIPES Act applies to operators of any underwater hazardous liquid pipeline facility located in an HCA that is not an offshore pipeline facility and any portion of which is located at depths greater than 150 feet under the surface of the water. Operators of these facilities, notwithstanding any pipeline integrity management program or integrity assessment schedule otherwise required by the Secretary, must ensure that pipeline integrity assessments using internal inspection technology appropriate for the pipeline's integrity threats are completed not less often than once every 12 months; and using pipeline route surveys, depth of cover surveys, pressure tests, ECDA, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, ensure that pipeline integrity assessments are completed on a schedule based on the risk that the pipeline facility poses to the HCA in which the pipeline facility is located. PHMSA has incorporated these requirements in a new § 195.454 as an addition to the pipeline integrity management requirements under Subpart F.

VI. Section-by-Section Analysis

§ 195.1 Which pipelines are covered by this part?

Version Sent to Federal Register

Section 195.1(a) lists the pipelines that are subject to the requirements in 49 CFR 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 it needs additional information about unregulated gathering lines to fulfill its statutory obligations, and it has determined it needs additional information about gravity lines to determine whether any safety regulations need to be extended to these lines as well. Accordingly, this final rule extends the reporting requirements in subpart B of part 195 to all gravity and gathering lines (whether regulated, unregulated, onshore, or offshore).

§ 195.2 Definitions.

Section 195.2 provides definitions for various terms used throughout part 195. On August 10, 2007, PHMSA published a policy statement and request for comment on the transportation of ethanol, ethanol blends, and other biofuels by pipeline (72 FR 45002). 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 modifying the definition of hazardous liquid in § 195.2 to conform it with 49 U.S.C. 60101(a)(4)(B) and clarify that the transportation of biofuel by pipeline is subject to the

Version Sent to Federal Register

requirements of 49 CFR part 195. Further, PHMSA is adopting a new definition for "Engineering Critical Assessment," which outlines procedures an operator must take if they choose to perform an analysis to determine whether a pipeline anomaly is less injurious than categorized by the regulations and whether the operator can extend the repair time frame.

Finally, PHMSA is also adopting a new definition of "Significant Stress Corrosion Cracking." This new definition, which comes from ASME STP-PT-011 and NACE SP0204-2008 and is widely used by industry, provides criteria for determining when operators must excavate and repair a probable crack defect in a pipeline segment.

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

Section 195.13 is added, which subjects gravity lines to the same annual, accident, and safety-related condition reporting requirements in subpart B of part 195 as other hazardous liquid pipelines.

§ 195.15 What reporting requirements apply to rural gathering lines that do not meet the definition of a regulated rural gathering?

Section 195.15 is added, which subjects otherwise unregulated rural gathering lines to the annual, accident and safety-related condition reporting requirements in subpart B of part 195 as other hazardous liquid pipelines.

§ 195.65 Safety Data Sheets

Section 195.65 contains the requirements for providing safety data sheets on spilled hazardous liquids following accidents. In accordance with Section 14 of the 2016 PIPES Act,

Version Sent to Federal Register

PHMSA is requiring owners and operators of hazardous liquid pipeline facilities, following accidents that result in hazardous liquid spills, to provide safety data sheets on those spilled hazardous liquids to the designated Federal On-Scene Coordinator and appropriate State and local emergency responders within 6 hours of a telephonic or electronic notice of the accident to the National Response Center. This is a self-executing provision from the 2016 PIPES Act that PHMSA is incorporating into Subpart B of the hazardous liquid pipeline safety regulations.

§ 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, this final rule repeals 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 are 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 final rule restructures the existing requirements into paragraphs (a) and (c) and adds a new provision in paragraphs (b) and (d) to ensure that all newly constructed, covered 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.

Version Sent to Federal Register

Section 195.401 prescribes general requirements for the operation and maintenance of hazardous liquid pipelines. PHMSA is modifying the pipeline repair requirements in § 195.401(b). PHMSA is retaining, without change, the requirements in paragraphs (b)(1) for non-IM repairs and (b)(2) for IM repairs. A new paragraph (b)(3) is 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, no matter whether those conditions are in HCAs or non-HCAs.

§ 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, this final rule establishes a new § 195.414 that requires 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 needed to promptly detect and remediate conditions that could affect the safe operation of pipelines in all areas. Accordingly, the final rule establishes a new § 195.416 that requires operators to perform an assessment, at least once every 10 years, of onshore transmission pipelines that are able to accommodate inline inspection tools and that are not already subject to the IM requirements. This assessment must be performed for the range of relevant threats to the pipeline segment by the use of an appropriate ILI tool(s) and account for

Version Sent to Federal Register

uncertainties in reported results. Operators must use a method capable of assessing seam integrity and corrosion and deformation anomalies when assessing LF-ERW pipe, lap-welded pipe, or pipe with a seam factor of less than 1.0. In lieu of performing an ILI assessment on their lines, operators can perform the assessment by using a pressure test, external corrosion direct assessment, or other technology (subject to prior notification, method being able to assess the threat, and "no objection" by PHMSA) that can be demonstrated as providing an equivalent understanding of the pipe's condition.

The regulation also requires 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 repair requirements in § 195.401(b)(1); and that all relevant information about the pipeline be considering in complying with the requirements of § 195.416. Consistent with the requirements in the revised § 195.452(h)(2) regarding the discovery of condition, in cases where the information necessary to make determination about pipeline threats cannot be obtained within 180 days following the date of inspection, pipeline operators must notify PHMSA and provide an expected date when adequate information will become available.

§ 195.444 Leak detection.

Section 195.444 contains the operation and maintenance requirements for Computational Pipeline Monitoring leak detection systems. PHMSA is amending the PSR so that all covered hazardous liquid pipelines have a leak detection system. Therefore, the final rule reorganizes the existing requirements of the regulation into paragraphs (a) and (c), and adds a new general

Version Sent to Federal Register

provision in paragraph (b) that requires operators to have leak detection systems on all covered pipelines and to consider certain factors in determining what kind of system is necessary to protect the public, property, and the environment.

§ 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 final rule clarifies the applicability of the deadlines in paragraph (b) for the development of a written program for new pipelines and low-stress pipelines in rural areas. Paragraph (c)(1)(i)(A) is amended to ensure that operators consider uncertainty in tool tolerance in reviewing the results of ILI assessments. The paragraph was also amended to be more consistent with paragraphs at § 195.416 stating that pipeline segments with identified or probable risks or threats related to cracks (such as at pipe body and weld seams) based on the risk factors specified in paragraph (e), an operator must use an ILI tool or tools capable of detecting crack anomalies. Paragraph (d) is 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, including seismicity, that might affect pipeline integrity. Paragraph (g) is amended to prescribe certain data points 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) is amended by modifying the criteria and incorporating the existing requirement in § 195.422 that repairs be made in a safe manner, but 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.

Version Sent to Federal Register

PHMSA is amending the existing "discovery of condition" language in the pipeline safety regulations. The revised § 195.452(h)(2) requires, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, that pipeline operators 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 is making additional amendments to § 195.452. Paragraph (j) is 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) is added to require that all pipelines in areas that could affect an HCA be made capable of accommodating ILI tools within 20 years, unless, subject to a petition and PHMSA approval, the basic construction of a pipeline will not permit that accommodation, the existence of an emergency renders such an accommodation impracticable, or the operator determines it would abandon or shut down a pipeline as a result of the cost to comply with the requirement of this section. Paragraph (n) requires that pipelines in newly identified HCAs after the 20-year period be made capable of accommodating ILIs within 5 years of the date of identification or before the performance of the baseline assessment, whichever is sooner. Paragraph (o) is added to allow operators additional time to integrate the additional attributes PHMSA has added to paragraph (g)(1). Finally, an explicit reference to seismicity is 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). PHMSA is also establishing the requirements for using an optional ECA to evaluate certain cracks and

Version Sent to Federal Register

crack-like conditions using either ILI tools or pressure testing under a new paragraph (p). The ECA requirements outline the specific procedures operators must use, the data that must be considered in making the calculations, and the documentation that operators must perform. The ECA must be reviewed and confirmed by a qualified technical subject matter expert in metallurgy and fracture mechanics. Operators are allowed to use "other technology" when performing ECAs if the operator can demonstrate that the assessment provides and equivalent understanding of the condition of the line pipe and upon obtaining a notice of "no objection" from PHMSA.

§ 195.454 Integrity Assessments for Certain Underwater Hazardous Liquid Pipeline Facilities Located in HCAs

Section 195.454 contains additional assessment requirements for operators of any underwater hazardous liquid pipeline facility located in an HCA that is not an offshore pipeline facility and any portion of which is located at depths greater than 150 feet under the surface of the water. In accordance with section 25 of the 2016 PIPES Act, PHMSA is requiring these operators to ensure that they complete pipeline integrity assessments not less often than once every 12 months using internal inspection technology appropriate for the integrity threats to the pipeline and complete pipeline integrity assessments using pipeline route surveys, depth of cover surveys, pressure tests, external corrosion direct assessment, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, on a schedule based on the risk that the pipeline facility poses to the HCA in which the pipeline facility is located. This is a self-executing provision from the 2016 PIPES Act that PHMSA is incorporating into Subpart F of the hazardous liquid pipeline safety regulations.

Version Sent to Federal Register

VII. Regulatory Notices

A. Statutory/Legal Authority for this Rulemaking

This final rule is published under the authority of the Federal Pipeline Safety Law (49 U.S.C. 60101 et seq.). Section 60102 authorizes the Secretary of Transportation to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities, as delegated to the PHMSA Administrator under 49 C.F.R. § 1.97.

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

This final rule is a significant regulatory action under Section 3(f) of Executive Order 12866 (58 FR 51735), and therefore was reviewed by the Office of Management and Budget. This final rule is significant under the Regulatory Policies and Procedures of the Department of Transportation (44 FR 11034) because of substantial congressional, State, industry, and public interest in pipeline safety.

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

Version Sent to Federal Register

Regulatory Review) and Executive Order 12866 (Regulatory Planning and Review) and is consistent with the requirements in both orders and 49 U.S.C. 60102(b)(5)-(6).

In the regulatory analysis, we discuss the alternatives to the amended requirements and, where possible, provide estimates of the benefits and costs for specific regulatory requirements by individual requirement areas. The regulatory analysis provides PHMSA's best estimate of the impact of the final rule requirements. As shown in the table below, PHMSA estimated the total annual costs of the rule at $16.4 million using a 3 percent discount rate and $17.6 million using a 7 percent discount rate.

Due to data limitations, PHMSA evaluated the benefits of the final rule qualitatively. Overall, the rule will provide direct benefits through avoiding damages from hazardous pipeline incidents that may be prevented through earlier detection of threats to pipeline integrity from corrosion or following extreme weather events, and through enhancing the ability of PHMSA and pipeline operators to evaluate risks. As context, operator-reported data for hazardous liquid incidents that occurred between 2010 and 2015 show reported damages of $88.6 million for pipelines outside HCAs and $300.8 million for pipelines inside HCAs on average each year, or about $768 and $3,572 per mile of pipeline, respectively. These damages are only a fraction of the total social costs of hazardous liquid releases but indicate the potential magnitude of benefits derived from preventing pipeline failures.

Version Sent to Federal Register

Annualized costs and benefits by requirement area, discounted using 3 percent and 7 percent discount rates (2015$).

Final Rule Requirement Area	3% discount rate		7% discount rate	
	Costs[1]	Benefits	Costs[1]	Benefits
1. Reporting requirements for gravity lines.	$5,000	Better risk understanding and management.[2]	$5,000	Better risk understanding and management.[2]
2. Reporting requirements for gathering lines.	$74,000	Better risk understanding and management.[3]	$74,000	Better risk understanding and management.[3]
3. Inspections of pipelines in areas affected by extreme weather events.	$0	$0	$0	$0
4. Assessments of pipelines that are not already covered under the IM program every 10 years.[4, 5]	$2,966,000	Avoided incidents and damages through detection of safety conditions.[7]	$2,966,000	Avoided incidents and damages through detection of safety conditions.[7]
5. IM repair criteria.	$0	$0	$0	$0
6. LDSs on pipelines located in non-HCAs.[5]	$8,373,700	Reduced damages through earlier detection and response.[6]	$9,546,600	Reduced damages through earlier detection and response.[6]
7. Increased use of ILI tools.	$0	$0	$0	$0
8. Clarify certain IM plan requirements.	$4,946,000	Reduced damages through prevention and earlier detection and response.[8]	$5,032,000	Reduced damages through prevention and earlier detection and response.[8]
Total	**$16,364,700**	**Reduced damages from avoiding and/or mitigating hazardous liquid releases**	**$17,623,600**	**Reduced damages from avoiding and/or mitigating hazardous liquid releases**

1. Costs in this table are rounded to the nearest thousand dollars and may differ from costs presented in individual sections of the document.

2. Gravity lines can present safety and environmental risks. Depending on the elevation change, a gravity flow pipeline could have more pressure than a pipeline with pump stations to boost the pressure. The benefits of this requirement are not quantified, but based on social costs of $42 per gallon for releases from regulated gathering lines (see Section 2.6.2), the information would need to lead to measures preventing the release of 120 gallons per year to generate benefits that equal the costs.

3. The benefits are not quantified, but based on social costs of $42 per gallon for releases from regulated gathering lines (see Section 2.6.2), the information would need to lead to measures preventing the release of 1,770 gallons per year to generate benefits that equal the costs.

4. PHMSA also conducted a sensitivity analysis that uses alternative baseline assumptions for pipelines not currently covered under the IM program. Specifically, PHMSA estimated the costs for two alternative scenarios: 1) a scenario that assumes that 100 percent of non-HCA mileage is assessed in the baseline; and 2) a scenario that assumes that 83 percent of the mileage is assessed in the baseline. Costs for these two scenarios are $0 and $5.9 million, respectively. See Section 3.4.3 for details.

5. The requirement is not applicable to gathering lines.

Version Sent to Federal Register

Final Rule Requirement Area	3% discount rate		7% discount rate	
	Costs[1]	Benefits	Costs[1]	Benefits
6. Given annual costs of $3.0 million and a cost per incident of $553,200, incremental assessment of pipelines outside of HCAs would need to prevent 5 incidents for benefits to equate costs. See Section 3.4.3 for details.				
7. As discussed in Section 2.6.2, 1,396 incidents involved non-HCA pipelines between 2010 and 2015, or an average of 233 incidents per year. The vast majority of these incidents (1,344 incidents in total or 224 per year, on average) do not involve gathering lines. Costs associated with incidents outside of HCAs (excluding gathering lines) average approximately $398,400 per incident, not including additional damages and costs that are excluded or underreported in the incident data.				
8. The benefits of reduced costs associated with the prevention or reduction of released hazardous liquids cannot be quantified but could vary in frequency and size depending on the types of failures that are averted. Including additional pipelines in the IM plan, integrating data, and conducting spatial analyses is expected to enhance an operator's ability to identify and address risk. The societal costs associated with incidents involving pipelines in HCAs average $1.9 million per incident (see Section 2.6.2). The annual cost estimates for this requirement are equivalent to the average damages from fewer than three such incidents. This is relative to an annual average of 158 incidents in HCAs between 2010 and 2015.				

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 exceed or otherwise justify the costs. A copy of the final RIA has been placed in the docket.

C. Executive Order 13132: Federalism

This final rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13132 ("Federalism"). This final rule does not adopt 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 adopt 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.

Version Sent to Federal Register

D. Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980 (Public Law 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 economic impact on small entities. The screening analysis is available in the docket for the rulemaking. PHMSA estimates that the final rule would impact fewer than 70 small hazardous liquid pipeline operators, and that the majority of these operators would experience annual compliance costs that represent less than 1 percent of

Version Sent to Federal Register

annual revenues. Fewer than 5 small operators would incur annual compliance costs that represent greater than 1 percent of annual revenues and none would incur annual compliance costs of greater than 3 percent 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 does not have a significant economic impact on a substantial number of small entities.

E. National Environmental Policy Act

PHMSA analyzed this final rule 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 determined that this action will not significantly affect the quality of the human environment. An environmental assessment of this rulemaking is available in the docket.

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

This final rule has been analyzed in accordance with the principles and criteria contained in Executive Order 13175 (“Consultation and Coordination with Indian Tribal Governments”). Because this final rule 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.

Version Sent to Federal Register

G. 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 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;

"Pipeline Safety: New Reporting Requirements for Hazardous Liquid Pipeline Operators: Hazardous Liquid Annual Report" identified under OMB Control Number 2137-0614; and

"National Registry of Pipeline and LNG Operators" identified under OMB Control Number 2137-0627.

PHMSA also proposes to create a new information collection to help operators comply with the proposed revision to the PSR that will require operators to notify PHMSA if they choose to use an alternative to an ILI device when conducting pressure tests on their pipelines. This collection will be titled: "Operator Notifications –Alternate Pressure Testing Method." PHMSA will request a new Control Number from OMB for this new information collection.

Version Sent to Federal Register

PHMSA will submit an information collection revision request to OMB for approval based on the requirements in this rule. The information collection is contained in the Federal Pipeline Safety Regulations, 49 CFR parts 190–199. 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: 12/31/2016.

   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 proposed rulemaking, 5 gravity line operators and 20 gathering line operators would be required to submit accident reports to PHMSA on occasion. These 25 additional operators will also be required to keep mandated records. Assuming that the frequency of accidents is the same for non-regulated gathering lines and gravity lines as it is for transmission lines, approximately 4 to 6 percent (approximately 1) of these newly

Version Sent to Federal Register

regulated operators will submit an accident report in any given year, with each report requiring 5 hours (4 hours of a compliance officer's time and 1 hour of a secretary/administrative assistant's time), based on a new form PHMSA developed specifically for incidents involving gravity and reporting-regulated gathering lines. This information collection is being revised to account for the additional burden that will be incurred by these newly regulated entities. Operators currently submitting accident 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: 848.

Total Annual Burden Hours: 52,434.

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: 7/31/2017.

Abstract: 49 USC 60102 requires each operator of a pipeline facility (except master meter operators) to submit to U.S. 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 proposed rule, approximately 5 gravity line operators and 20 gathering line operators

Version Sent to Federal Register

will be required to adhere to the safety-related condition reporting requirements. PHMSA estimates that, on average each year, 5 percent (approximately 1) of these newly affected operators will submit safety-related condition reports. PHMSA estimated that each report requires 6 hours, with 4 hours of a compliance officer's time and 2 hours of a secretary/administrative assistant's time. 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: 143.

Total Annual Burden Hours: 858.

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: 10/31/2019.

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 rulemaking action, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of inspection, pipeline operators are required to notify PHMSA in

Version Sent to Federal Register

writing and provide an expected date when adequate information will become available. PHMSA estimates that only 1 percent of repair reports (approx. 74) will require these notifications each year. Operators are authorized to send the notification, via email, to PHMSA's Information Resources Manager. PHMSA estimates that it will take operators 30 minutes to create and send each notification resulting in an overall burden increase of 37 hours annually.

Affected Public: Owners and operators of Hazardous Liquid Pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 278.

Total Annual Burden Hours: 325,507.

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: 12/31/2015.

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 to compile a national pipeline inventory, identify safety problems, and target inspections. As a result of this proposed rule, approximately 5 gravity line operators and 20 gathering line operators will be required to submit annual reports to PHMSA. PHMSA estimated recordkeeping and reporting

Version Sent to Federal Register

activities associated with the annual report at 19 hours, composed of 12 hours of a compliance officer's time and 7 hours of a secretary/administrative assistant's time. This information collection is being revised to account for the additional burden that will be incurred by the newly affected operators. 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: 472.

Total Annual Burden Hours: 8,932

Frequency of Collection: Annually.

5. Title: National Registry of Pipeline and LNG Operators.

OMB Control Number: 2137-0627.

Current Expiration Date: 05/31/2018.

Abstract: The National Registry of Pipeline and LNG Operators serves as the storehouse for the reporting requirements for an operator regulated under or subject to reporting requirements of 49 CFR parts 191, 192, 193, or 195. As a result of this provision in this rule, approximately 5 gravity line operators and 20 gathering line operators will be required to register their pipeline with the National Pipeline Registry and apply for an Operator Identification number (OPID). PHMSA estimates that this activity will take 1 hour per operator. These operators will also be required to notify PHMSA of certain changes made to their pipeline system when applicable. PHMSA estimates that 5 percent

Version Sent to Federal Register

(approximately 1) of these newly regulated operators will make these notifications each year. PHMSA estimates that this activity will take 1 hour per operator. This information collection is being revised to account for the additional burden that will be incurred by the newly regulated operators. Operators currently registered will not be otherwise impacted by this rule.

Affected Public: Natural gas, LNG, and hazardous liquid pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 656.

Total Annual Burden Hours: 656.

6. Title: Operator Notifications: "Requirements for Pipelines Not Subject to Integrity Management"

OMB Control Number: Will request from OMB.

Current Expiration Date: N/A.

Abstract: Owners and operators of hazardous liquid pipelines that are not subject to the integrity management requirements in 49 CFR §195.452 will be required to provide PHMSA with notifications under certain conditions. Operators will be required to notify PHMSA, in writing, in cases where a determination about pipeline threats has not been obtained within 180 days following the date of an inspection. Operators are required to provide an expected date when adequate information will become available. PHMSA expects 1 percent of operators who are not subject to integrity management requirements to make these notifications each year (approx. 4 operators). Operators are authorized to

Version Sent to Federal Register

send the notification, via email, to PHMSA's Information Resources Manager. PHMSA estimates that it will take operators 30 minutes to make each notification resulting in an annual burden of 2 hours. Operators are also required to notify PHMSA when they are unable to assess their pipeline via an in-line inspection. Operators who choose to use a different method of pressure-testing must demonstrate that their pipeline is not capable of accommodating an in-line inspection tool and that the use of an alternative assessment method will provide a substantially equivalent understanding of the condition of the pipeline. PHMSA estimates that operators will submit approximately 10 notifications each year regarding these conditions. Further, PHMSA estimates that each notification will take 10 hours, which includes the time to assemble the necessary information to demonstrate that the pipeline is not capable of accommodating an ILI tool and specify that the alternative assessment method will provide a substantially equivalent understanding of the pipeline. This will result in an annual burden of 100 hours.

Affected Public: Owners and operators of hazardous liquid pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 14.

Total Annual Burden Hours: 102.

Frequency of Collection: Annually.

7. Title: Operator Notifications: Extreme Weather Conditions

OMB Control Number: Will request from OMB.

Current Expiration Date: N/A.

Version Sent to Federal Register

Abstract: Following an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar events that have the likelihood of damage to infrastructure, an operator must inspect all potentially affected pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline. The inspection must commence within 72 hours of the extreme weather event. In the event that the operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable. PHMSA expects to receive 100 of these notifications annually. PHMSA believes extreme weather conditions could potentially affect all operators. Therefore, PHMSA estimates that it could receive up to 446 of these notifications each year. PHMSA believes it will take operators 30 minutes to make this notification. Operators may contact the Regional Director by phone or electronically.

Affected Public: Owners and operators of hazardous liquid pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 446.

Total Annual Burden Hours: 223.

Frequency of Collection: Annually.

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

Version sent to Federal Register

Comments are invited on:

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

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

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

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

Send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street, N.W., Washington, D.C. 20503. Comments should be submitted on or prior **to [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

H. 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.

I. Regulation Identifier Number (RIN)

Version Sent to Federal Register

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 amends 49 CFR part 195 as follows:

PART 195 – TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

1. Revise the authority citation for part 195 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. Amend § 195.1 by adding paragraph (a)(5) and revising paragraphs (b)(2) and (b)(4) to read as follows:

§ 195.1 Which pipelines are covered by this part?

(a) * * *

Version Sent to Federal Register

(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.

(b) * * *

(2) Except for the reporting requirements of subpart B of this part, see § 195.13, transportation of a hazardous liquid through a pipeline by gravity.

* * * * *

(4) Except for the reporting requirements of subpart B of this part, see § 195.15, transportation of petroleum through an onshore rural gathering line that does not meet the definition of a "regulated rural gathering line" as provided in § 195.11. This exception does not apply to gathering lines in the inlets of the Gulf of Mexico subject to **§** 195.413.

* * * * *

3. Amend § 195.2 by revising the definition for "*Hazardous liquid*" and adding definitions for *"Engineering Critical Assessment"* and "*Significant stress corrosion cracking*" in alphabetical order to read as follows:

§ 195.2 Definitions.

* * * * *

Engineering Critical Assessment (ECA) is an analytical procedure, based on fracture mechanics principles and finite element analysis techniques, that analyzes flaw size, material properties, stress, strain, maximum operating pressures, pressure cycling, and flaw growth for the

Version Sent to Federal Register

determination of maximum tolerable flaw sizes for imperfections in steel pipe, including girth welds and seam welds, to maintain safe pipeline operations.

* * * * *

Hazardous liquid means petroleum, petroleum products, anhydrous ammonia, and ethanol or other non-petroleum fuel, including biofuel, which is flammable, toxic, 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. Add § 195.13 to subpart A to read as follows:

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

(a) *Scope.* Pipelines transporting hazardous liquids by gravity must comply with the reporting requirements of subpart B of this part.

(b) *Implementation period.*

(1) *Annual reporting*. Comply with the annual reporting requirements in subpart B of this part by **[date 12 months after effective date of the final rule]**.

Version Sent to Federal Register

(2) Ac*cident and safety-related reporting*. Comply with the accident and safety-related condition reporting requirements in subpart B of this part by **[date 6 months after effective date of the final rule]**.

(c) *Exceptions*.

(1) This section does not apply to the transportation of a hazardous liquid in a gravity line that meets the definition of a low-stress pipeline, travels no farther than 1 mile from a facility boundary, and does not cross any waterways used for commercial navigation.

(2) The reporting requirements in §§ 195.52, 195.61, and 195.65 do not apply to the transportation of a hazardous liquid in a gravity line.

(3) The drug and alcohol testing requirements in part 199 of this subchapter do not apply to the transportation of a hazardous liquid in a gravity line.

5. Add § 195.15 to subpart A to read as follows:

§ 195.15 What reporting requirements apply to unregulated gathering lines?

(a) *Scope*. Gathering lines that do not otherwise meet the definition of a regulated rural gathering line in § 195.11 and any gathering line not already covered under § 195.1(a)(1), (2), (3) or (4) must comply with the reporting requirements of subpart B of this part.

(b) *Implementation period*.

(1) *Annual reporting*. Operators must comply with the annual reporting requirements in subpart B of this part by **[insert date 12 months after effective date of the final rule].**

Version sent to Federal Register

(2) *Accident and safety-related condition reporting*. Operators must comply with the accident and safety-related condition reporting requirements in subpart B of this part by **[date 6 months after effective date of the final rule]**.

(c) *Exceptions*.

(1) This section does not apply to those gathering lines that are otherwise excepted by § 195.1(b)(3), (b)(4), (b)(5), or (b)(6).

(2) The reporting requirements in §§ 195.52, 195.61, and 195.65 do not apply to the transportation of a hazardous liquid in a gathering line that is specified in paragraph (a) of this section.

(3) The drug and alcohol testing requirements in part 199 of this subchapter do not apply to the transportation of a hazardous liquid in a gathering line that is specified in paragraph (a) of this section.

6. Add § 195.65 to Subpart B to read as follows:

§ 195.65 Safety Data Sheets.

(a) Each owner or operator of a hazardous liquid pipeline facility, following an accident involving a pipeline facility that results in a hazardous liquid spill, must provide safety data sheets on any spilled hazardous liquid to the designated Federal On-Scene Coordinator and appropriate State and local emergency responders within 6 hours of a telephonic or electronic notice of the accident to the National Response Center.

(b) Definitions. In this section:

Version Sent to Federal Register

(1) *Federal On-Scene Coordinator*. The term "Federal On-Scene Coordinator" has the meaning given such term in section 311(a) of the Federal Water Pollution Control Act (33 U.S.C. 1321(a)).

(2) *National Response Center*. The term "National Response Center" means the center described under 40 CFR 300.125 (a).

(3) *Safety Data Sheet.* The term "safety data sheet" means a safety data sheet required under 29 CFR 1910.1200.

7. Revise § 195.120 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

Version Sent to Federal Register

(6) Offshore pipelines, other than 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 PHMSA denies the petition, 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.

8. Revise § 195.134 to read as follows:

§ 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*.

(1) For each pipeline constructed prior to **[insert date of Federal Register publication]**. Each pipeline must have a system for detecting leaks that complies with the requirements in § 195.444 by **[insert date 5 years after the date of publication.]**

Version Sent to Federal Register

(2) For each pipeline constructed on or after **[insert date of Federal Register publication]**. Each pipeline must have a system for detecting leaks that complies with the requirements in § 195.444 by **[insert date 1 year after the date of publication in the Federal Register].**

(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.

(d) *Exception*. The requirements of paragraph (b) of this section do not apply to offshore gathering or regulated rural gathering lines.

9. Revise § 195.401 by adding paragraph (b)(3) to read as follows.

§ 195.401 General requirements.

* * * * *

(b) * * *

(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.

* * * * *

10. Add § 195.414 to read as follows:

Version Sent to Federal Register

§ 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, landslide, a natural disaster, or other similar events that have the likelihood of damage to infrastructure, an operator must inspect all potentially affected pipeline facilities to detect conditions 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 initial inspection to determine the extent of any damage and the need for the additional assessments required under paragraph (a) of this section.

(c) *Time period*. The inspection required under paragraph (a) of this section must commence within 72 hours after the cessation of the event, defined as the point in time when 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. In the event that the operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

(d) *Remedial action*. An operator must take prompt and 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:

Version Sent to Federal Register

(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.

11. Add § 195.416 to read as follows:

§ 195.416 Pipeline assessments.

(a) *Scope*. This section applies to onshore transmission line pipe that can accommodate inspection by means of in-line inspection tools and is not subject to the integrity management requirements in § 195.452.

(b) *General*. An operator must perform an initial assessment of each of its pipeline segments by December 31, 2027, and perform periodic assessments of its pipeline segments at least once every 10 calendar years from the year of the prior assessment or as otherwise necessary to ensure public safety or the protection of the environment.

(c) *Method.* Except as specified in paragraph (d) of this section, an operator must perform the integrity assessment for the range of relevant threats to the pipeline segment by the use of an appropriate in-line inspection tool(s). An operator must explicitly consider uncertainties in

Version Sent to Federal Register

reported results (including tool tolerance, anomaly findings, and unity chart plots or other equivalent methods for determining uncertainties) in identifying anomalies. If this is impracticable based on operational limits, including operating pressure, low flow, and pipeline length or availability of in-line inspection tool technology for the pipe diameter, then the operator must perform the assessment using methods (1), (2), or (3) of this paragraph, where they are appropriate for the threat being assessed. The methods an operator selects to assess electric flash welded pipe, low-frequency electric resistance welded pipe, direct-current electric resistance welded pipe, lap-welded pipe, pipe with a seam factor less than 1.0 as defined in §195.106(e), or pipe that is susceptible to longitudinal seam failure based on known risks or threats due to manufacturing processes, assessments, or in-service leaks or failures, must be capable of assessing seam integrity, cracking, and of detecting corrosion and deformation anomalies. The following alternative assessment methods may be used as specified in this paragraph:

(1) A pressure test conducted in accordance with subpart E of this part;

(2) External corrosion direct assessment in accordance with § 195.588; or

(3) Other technology in accordance with paragraph (d).

(d) *Other technology.* Operators may elect to use other technologies if the operator can demonstrate the technology can provide an equivalent understanding of the condition of the line pipe for threat being assessed. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment by:

(1) Sending the notification, along with the information required to demonstrate compliance with this paragraph, to the Information Resources Manager, Office of Pipeline

Version Sent to Federal Register

Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590; or

(2) Sending the notification, along with the information required to demonstrate compliance with this paragraph, to the Information Resources Manager by facsimile to (202) 366-7128.

(3) Prior to conducting the "other technology" assessments, the operator must receive a notice of "no objection" from the PHMSA Information Services Manager or Designee.

(e) *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. Operators must consider uncertainties in any reported results (including tool tolerance) as part of that analysis.

(f) *Discovery of condition*. For purposes of § 195.401(b)(1), discovery of a condition occurs when an operator has adequate information to determine that a condition presenting a potential threat to the integrity of the pipeline exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make that determination required under paragraph (e) of this section, unless the operator can demonstrate the 180-day interval is impracticable. If the operator believes that 180 days are 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. This notification must be made in accordance with § 195.452 (m).

Version Sent to Federal Register

(g) *Remediation.* An operator must comply with the requirements in § 195.401 if a condition that could adversely affect the safe operation of a pipeline is discovered in complying with paragraphs (e) and (f) of this section.

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

12. Revise § 195.444 to read as follows:

§ 195.444 Leak detection.

(a) *Scope.* Except for offshore gathering and regulated rural gathering pipelines, this section applies to all hazardous liquid pipelines transporting liquid in single phase (without gas in the liquid).

(b) *General.* A pipeline must have an effective system for detecting leaks. An operator must evaluate the capability of its leak detection system to protect the public, property, and the environment and modify it as necessary to do so. At a minimum, an operator's evaluation must 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. Amend § 195.452 by:

Version Sent to Federal Register

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

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

c. Revising paragraphs (j)(1), (j)(2), and (j)(3);

d. Adding paragraphs (n), (o), and (p).

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 by risk assessment that a 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, and low-stress pipelines in rural areas under § 195.12.

Version Sent to Federal Register

(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 no 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 for low stress pipelines in rural areas.

* * * * *

(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 an in-line inspection tool described in method (A) of this paragraph. If it is impracticable based upon the construction of the pipeline (e.g., diameter changes, sharp bends, and elbows) or operational limits including operating pressure, low flow, pipeline length, or availability of in-line inspection tool technology for the pipe diameter, then the operator must use methods (B), (C), or (D) of this paragraph as appropriate. The methods an operator selects to assess electric flash welded pipe, low-frequency electric resistance welded pipe, direct-current electric resistance welded pipe, lap-welded pipe, pipe with a seam factor less than 1.0 as defined in § 195.106(e), or pipe that is otherwise susceptible to longitudinal seam

Version Sent to Federal Register

failure based on known risks or threats due to manufacturing processes, assessments, or in-service leaks or failures, must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

(A) In-line inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges, and grooves. For pipeline segments with an identified or probable risk or threat related to cracks (such as at pipe body and weld seams) based on the risk factors specified in paragraph (e), an operator must use an in-line inspection tool or tools capable of detecting crack anomalies. 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 a new or conversion-to-service pipeline begins operation through the development of procedures, identification of high consequence areas, and pressure testing of could-affect high consequence areas in accordance with § 195.304.

(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 1 year from the date that the information is obtained. An operator must complete the baseline assessment of any pipeline segment that could affect a

Version Sent to Federal Register

newly identified high consequence area within 5 years from the date an operator identifies the area.

* * * * *

(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. Operators must continue to comply with the data integration elements specified in § 195.452(g) that were in effect on October 1, 2016, until **[insert date 3 years after publication of rule]**. Operators must begin to integrate all the data elements specified in this section starting **[insert date 1 year after publication of rule]** with all attributes integrated by **[insert date 3 years after publication of rule]**. This analysis must:

(1) Integrate information and attributes about the pipeline that 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) and temperature;

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

Version Sent to Federal Register

(v) Hydrostatic test pressure including any test failures or leaks – 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 repairs and 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.

Version Sent to Federal Register

(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 as required in this section. 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 as described in this section. An operator must comply with all other applicable requirements in this part in remediating a condition. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe and timely manner and are made so as to prevent damage to persons, property, or the environment. The calculation method(s) used for anomaly evaluation must be applicable for the range of relevant threats.

* * * * *

Version Sent to Federal Register

(2) *Discovery of condition*. Discovery of a condition occurs when an operator has adequate information to determine that a condition presenting a potential threat to the integrity of the pipeline exists. An operator must promptly, but no later than 180 days after an assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate the 180-day interval is impracticable. If the operator believes that 180 days are 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 repairs these conditions. An operator must calculate the temporary reduction in operating pressure using the formulas in § 195.452 (h)(4)(i)(B), if applicable, or by using a pressure reduction determination in accordance with § 195.106 and the appropriate remaining pipe wall thickness when the formulas in § 195.452 (h)(4)(i)(B) are not applicable, or if all of these are unknown, a minimum 20 % or greater operating pressure reduction below the highest operating pressure actually experienced at the location of the defect within the 2 months preceding the inspection 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

Version Sent to Federal Register

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 metal loss defect where a calculation of the remaining strength of the pipe at the anomaly shows a predicted failure 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) Significant stress corrosion cracking. Alternatively, the operator must immediately remediate any stress corrosion cracking (SCC) meeting the following criteria:

(1) Crack depth plus any corrosion is greater than 50% of pipe wall thickness;

(2) Crack depth plus any corrosion is greater than the inspection tool's maximum measurable depth; or

(3) The SCC anomaly has a predicted failure pressure determined using an engineering critical assessment in accordance with § 195.452(p) that is less than 125% of the MOP, unless a more conservative criterion is appropriate for the pipe's mechanical properties, defect

Version Sent to Federal Register

characteristics, crack evaluation technique, inspection tool tolerances, and any other operational conditions expected prior to the required assessment in § 195.452(h)(4)(ii). Immediate anomaly repairs that are delayed by engineering critical assessment results must be remediated prior to the predicted failure pressure being less than 125% of the maximum operating pressure.

(F) Selective seam weld corrosion (SSWC) associated with electric flash welded (EFW) seams, low-frequency or direct-current electric resistance welded (ERW) seams, lap-welded pipe, or with historical seam integrity risks known from manufacturing processes or in-service leaks or failures. Alternatively, the operator must immediately remediate all SSWC meeting any of the following criteria:

(1) Crack depth plus any corrosion is greater than 50% of pipe wall thickness;

(2) Crack depth plus any corrosion is greater than the inspection tool's maximum measurable depth; or

(3) The SSWC anomaly has a predicted failure pressure determined using an engineering critical assessment in accordance with § 195.452(p) that is less than 125% of the maximum operating pressure, unless a more conservative criterion is appropriate for the pipe's mechanical properties, defect characteristics, crack evaluation technique, inspection tool tolerances, and any other appropriate operational conditions that may make the pipe become unsafe, including fatigue life, pressure cycling, or other operational conditions expected prior to the required assessment in § 195.452(h)(4)(ii). Immediate anomaly repairs that are delayed by engineering critical assessment results must be remediated prior to the predicted failure pressure becoming less than 125% of the maximum operating pressure.

Version Sent to Federal Register

(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 § 195.452(h)(4)(i), an operator must evaluate and remediate the following conditions 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 metal loss defect where a calculation of the remaining strength of the pipe at the anomaly shows a predicted failure pressure less than 1.39 times the maximum operating pressure at that location. 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) and must include the internal design safety factors in § 195.106. The calculation method(s) used for anomaly evaluation must be applicable for the range of relevant threats.

Version Sent to Federal Register

(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, 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, groove, or other stress riser greater than 12.5% of nominal wall.

(J) Stress corrosion cracking (SCC) that meets any of the following criteria or which was not remediated in accordance with § 195.452(h)(4)(i)(E):

(1) Crack depth plus any corrosion is greater than 50% of pipe wall thickness;

(2) Crack depth plus any corrosion is greater than the maximum measurable inspection depth of the assessment tool used; or

(3) The SCC anomaly has a predicted failure pressure determined in accordance with § 195.452(p) that is less than 100% of the pressure at the specified minimum yield strength or 1.39 times the maximum operating pressure, unless a more conservative criterion is appropriate for the pipe's mechanical properties, defect characteristics, crack evaluation technique, inspection tool tolerances, and any other appropriate operational conditions that may make the pipe become unsafe, including fatigue life, pressure cycling, or other operational conditions expected prior to the required assessment in § 195.452(j).

(K) Selective seam weld corrosion (SSWC) associated with EFW seams, lap-welded pipe, low-frequency or direct-current ERW seams, or other historical seam integrity risks known

Version Sent to Federal Register

from manufacturing processes, assessments, or in-service leaks or failures, that meets any of the following criteria or which was not remediated in accordance with § 195.452(h)(4)(i)(F):

(1) Crack depth plus any corrosion is greater than 50% of pipe wall thickness; or

(2) Crack depth plus any corrosion is greater than the maximum measurable inspection depth of the inspection tool used; or

(3) The SSWC anomaly has a predicted failure pressure determined in accordance with § 195.452(p) that is less than 100% of the pressure at the specified minimum yield strength or 1.39 times the maximum operating pressure, unless a more conservative criterion is appropriate for the pipe mechanical properties, defect characteristics, crack evaluation technique, inspection tool tolerances, and any other appropriate operational conditions that may make the pipe become unsafe, including fatigue life, pressure cycling, or other operational conditions expected prior to the required assessment in § 195.452(j).

(iii) *Other Conditions.* In addition to the conditions listed in § 195.452(h)(4), an operator must evaluate any condition identified by an integrity assessment or information analysis using appropriate predictive modeling of corrosion growth, crack growth, and cyclic fatigue life to establish if the remaining strength of the pipe could become less than 1.1 times the maximum operating pressure prior to the next assessment established in accordance with § 195.452(j). If the evaluation shows that the anomaly condition could cause the remaining strength of the pipe to become less than 1.1 times the maximum operating pressure prior to the next integrity assessment, the operator must schedule the condition for remediation and take appropriate action with procedures and remediation to correct and remedy any condition that could adversely affect

Version Sent to Federal Register

the safe operation of a pipeline system before the next assessment. 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 an operator should consider new risk factors, 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

Version Sent to Federal Register

annual verification under this paragraph no later than **[date 1 year after effective date of the final rule].**

(3) *Assessment intervals.* An operator must establish 5-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section. When establishing reassessment intervals for pipelines with known or suspected remaining cracks or crack-like defects; pipe with electric flash welded (EFW), low-frequency, or direct-current electric resistance welded (ERW) seams; lap-welded pipe; or pipe with historical seam integrity risks based on manufacturing processes, assessments, or in-service seam leaks or failures; the maximum reassessment interval may not exceed one-half of the remaining life determined by an engineering critical assessment conducted in accordance with in § 195.452(p).

* * * * *

(n) *Accommodation of instrumented 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 **[insert 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)(2) of this section) after **[insert date 15 years from effective date of the**

Version Sent to Federal Register

final rule], an operator must modify the pipeline to accommodate the passage of an instrumented internal inspection device within 5 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 instrumented internal inspection device or that the operator determines it would abandon or shut-down a pipeline as a result of the cost to comply with the requirement of this section.

(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. An operator must file such a petition 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 1 year after the date of the notice of the denial.

(o) *Transition date.* The effective date of the final rule published on **[insert date of publication]** is **[insert effective date of rule].** Operators must begin compliance with the amendments to paragraph (g) of this section by **[insert date 1 year after publication]** and complete compliance with the amendments to paragraph (g) of this section by **[insert date 3 years after publication].**

(p) *Engineering Critical Assessment.* Whenever an engineering critical assessment of the remaining life of the pipeline with cracks and crack-like defects is required or allowed by this part, operators must perform such engineering critical assessments in accordance with this

Version Sent to Federal Register

paragraph. The engineering critical assessment must be performed to determine the predicted failure pressure of the as-discovered condition and the remaining life for the pipeline at the defect location using applicable fracture mechanics modeling techniques, pressure cycle analysis, crack growth fatigue models, and failure mode analysis (brittle, ductile, or both) for the microstructure (i.e., heat-affected zone, bond line, parent pipe, etc.). The operator must perform the engineering critical assessment as follows:

(1) The predicted failure pressure must be calculated using technically proven fracture mechanics evaluation methods that are appropriate for whether the crack defect is in ductile, brittle, or both material types. The analysis must conservatively account for model inaccuracies and tolerances for assessing axial flaws and failure modes.

(2) The operator must perform crack growth analysis to determine the remaining life of the pipeline at the maximum operating pressure based on the largest remaining critical crack flaw size remaining in the pipeline segment, using a lower-bound toughness for the applicable parent pipe, weld heat-affected zone, or weld metal bond line; any pipe failure or leak mechanisms identified during any pressure testing or other operations; pipe characteristics; material mechanical properties (including toughness); failure mechanism for the microstructure (ductile and brittle or both); location and type of defect; operating environment; operation conditions, including pipe operating temperatures; and pressure cycling induced fatigue. The analysis must use proven methods and procedures for analyzing crack growth (both length and depth), crack interactions, and crack coalescence within the cluster of cracks in the identified defect. Fatigue analysis must be performed using a recognized form of the Paris Law or other technically appropriate engineering methodology validated by a qualified technical expert(s) in metallurgy

Version Sent to Federal Register

and fracture mechanics to give conservative predictions of flaw growth and remaining life. When assessing other degradation processes (other than pressure cycling), an operator must perform the analysis using recognized rate equations where the applicability and validity are demonstrated for the case being evaluated. The analysis must include a sensitivity analysis to determine conservative estimates of time to failure for any known or potential remaining cracks in the pipe. The sensitivity analysis to determine the time to failure for a crack must include operating history, pressure cycles, pressure tests, pipe geometry, wall thickness, strength level, flow stress, Charpy V-Notch energy values for the operating temperature, other applicable operating conditions, and the operating environment for the pipe segment being assessed, including the role of the pressure-cycle spectrum and any significant changes in the actual versus predicted pressure-cycle spectrum.

(3) Data used in the calculations must use all of the following as appropriate:

(i) Mechanical properties that are known or conservative assumptions of mechanical properties. The analysis must account for metallurgical properties at the location being analyzed. Material strength and toughness values used in the analysis must reflect the local conditions at the defect location or segment being analyzed (such as in the properties of the parent pipe, weld heat-affected zone, or weld metal bond line) and use data that is applicable to the specific line pipe vintage and segment. When the strength and toughness and limits or ranges are unknown, the analysis must assume material strength and fracture toughness levels corresponding to the pipe vintage and type. For pipe body or weld crack assessments, use the actual ranges of values of strength and toughness that are known from tests of similar material; conduct destructive material tests of the pipe; determine material properties based upon other appropriate

Version Sent to Federal Register

nondestructive examination technology; or use conservative values based on technical research publications that an operator demonstrates provides conservative Charpy V-Notch energy values of the crack-related conditions and conservative strength values of the line pipe appropriate for the seam type. Testing programs to determine pipe and seam material properties must test a statistically valid number of pipe segment samples to ensure values used are no more than a 10% standard deviation with a 90% confidence that the material properties used in the analysis are valid and in the low range of the confidence interval, with a minimum of at least 5 tests for each type of pipe. For pre-1970s pipe; material that is considered to be brittle; or where vintage material, technology, or other technical publications are not available or applicable, evaluations must use Charpy V-Notch upper-shelf energy levels lower than or equal to: 5.0 ft-lb for body cracks and 1.0 ft-lb for LF-ERW pipe seam bond line defects such as cold weld, lack of fusion, and selective seam weld corrosion.

(ii) Crack length and depth dimensions obtained from *in situ* direct measurements on the pipe, from crack detection in-line inspection tools for cracking, or from the largest calculated remaining crack from a hydrostatic pressure test.

(A) For cases that analyze remaining flaw sizes measured using crack detection in-line inspection tool data, the analysis must use flaw dimensions and characteristics that conservatively account for in-line inspection tool inaccuracies and measurement tolerances, and the operator must confirm inaccuracies and measurement tolerances through direct *in situ* non-destructive examination using technology that has been validated to detect and measure tight cracks. In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance, tool accuracy, tool tolerance, and evaluation standards,

Version Sent to Federal Register

including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection and in metallurgy and fracture mechanics for accuracy for the type of defects and pipe material being evaluated.

(B) For cases where operators evaluate remaining life for pipe segments that have successfully passed a hydrostatic test, operators must conservatively determine the largest flaw size(s), i.e., crack length and depth, that could have survived the hydrostatic pressure test using appropriate upper-bound values of material strength and toughness with full-size equivalent Charpy upper-shelf energy levels and flow stress (equal to the ultimate tensile strength) of the base pipe or weld material to calculate the largest defects that could have survived the hydrostatic test.

(iii) The engineering critical assessment must account for the likely failure mode of anomalies (such as brittle fracture, ductile fracture, or both). If the likely failure mode is uncertain or unknown, the analysis must analyze both failure modes and use the more conservative result. Fracture mechanics modeling that is technically appropriate for the anomaly type must be used to determine failure stress pressures. Brittle failure mode analysis must use linear-elastic failure criteria such as the Raju/Newman stress-intensity solutions or other technically proven approaches. Ductile failure mode analysis must use technically appropriate failure criteria such as the Modified LnSec, CorLas, Pipe Axial Flaw Failure Criteria, API 579 Level-II, or other technically proven approaches. Operators may use other technically proven-equivalent engineering fracture mechanics models, which can be shown to accurately predict the response obtained across the full-scale test database for the feature of concern or the worst-case

Version Sent to Federal Register

scenario involving sharp crack-like features or actual cracking, for determining conservative failure pressures for the specific failure mode.

(iv) When establishing reassessment intervals for pipelines with known or suspected remaining cracks or crack-like defects; pipe with electric flash welded (EFW) seams, low-frequency, or direct-current electric resistance welded (ERW) seams; lap-welded pipe; or pipe with any history of in-service seam leaks or seam failures based on manufacturing processes, assessments, or in-service leaks or failures; the maximum reassessment interval may not exceed one-half of the remaining life determined by an engineering critical assessment conducted in accordance with § 195.452(p). However, PHMSA will consider as "other technology," the use of a shorter reassessment interval if technically documented and justified.

(v) If any operating conditions that might affect the remaining life of the pipeline change, then the remaining life must be reanalyzed and recalculated within 6 months of the change.

(vi) The analysis must be reviewed and confirmed by a qualified technical subject matter expert in metallurgy and fracture mechanics.

(vii) The operator must document the following:

(A) The technical approach used for the analysis;

(B) All data used and analyzed;

(C) Pipe and weld properties;

(D) Procedures used;

(E) Evaluation methodology used;

(F) Models used;

(G) Direct *in situ* examination data;

Version Sent to Federal Register

(H) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;

(I) Pressure test data and results;

(J) In-the-ditch assessments;

(K) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;

(L) All finite element analysis results;

(M) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;

(N) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;

(O) Safety factors used for fatigue life and/or predicted failure pressure calculations;

(P) Reassessment time interval and safety factors;

(Q) The date of the review;

(R) Confirmation of the results by a qualified technical subject matter expert(s) in metallurgy and fracture mechanics and finite element analysis techniques; and

(S) Approval by responsible operator management personnel.

(4) Operators may use “other technology” for engineering critical assessments if the operator demonstrates that the assessment provides an equivalent understanding of the condition of the line pipe. Such “other technology” methodologies may include different or improved crack assessment methodologies, fracture mechanics evaluation methods, crack growth evaluation methods, fatigue models, and remaining life models, as well as differing or less-conservative

Version Sent to Federal Register

assumptions for pipe and seam properties, or any other aspect of the operator's engineering critical assessment methodology that does not comply with the requirements of this section. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before implementing the engineering critical assessment by:

(i) Sending the notification, along with the information required to demonstrate compliance with paragraph (f)(3)(viii) 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

(ii) Sending the notification, along with the information required to demonstrate compliance with paragraph (f)(3)(viii) of this section, to the Information Resources Manager by facsimile to (202) 366-7128.

(iii) Prior to conducting the "other technology" assessments, the operator must receive a notice of "no objection" from the PHMSA Information Services Manager or Designee.

14. Add § 195.454 to Subpart F to read as follows:

§ 195.454 Integrity Assessments for Certain Underwater Hazardous Liquid Pipeline Facilities Located in HCAs.

Notwithstanding any pipeline integrity management program or integrity assessment schedule otherwise required under § 195.452, each operator of any underwater hazardous liquid pipeline facility located in an HCA that is not an offshore pipeline facility and any portion of which is located at depths greater than 150 feet under the surface of the water must ensure that:

Version Sent to Federal Register

(a) Pipeline integrity assessments using internal inspection technology appropriate for the integrity threats to the pipeline are completed not less often than once every 12 months, and;

(b) Pipeline integrity assessments using pipeline route surveys, depth of cover surveys, pressure tests, external corrosion direct assessment, or other technology that the operator demonstrates can further the understanding of the condition of the pipeline facility, are completed on a schedule based on the risk that the pipeline facility poses to the HCA in which the pipeline facility is located.

Issued in Washington, DC on January 10, 2017, under authority delegated in 49 CFR Part 1.97.

Marie Therese Dominguez,
Administrator.

Version Sent to Federal Register