DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA–2011–0023]

RIN 2137–AE72

Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines

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

ACTION: Notice of proposed rulemaking.

SUMMARY: This Notice of Proposed Rulemaking (NPRM) proposes to revise the Pipeline Safety Regulations applicable to the safety of onshore gas transmission and gathering pipelines. PHMSA proposes changes to the integrity management (IM) requirements and proposes changes to address issues related to non-IM requirements. This NPRM also proposes modifying the regulation of onshore gas gathering lines.

DATES: Persons interested in submitting written comments on this NPRM must do so by June 7, 2016.

ADDRESSES: You may submit comments identified by the docket number PHMSA–2011–0023 by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the online instructions for submitting comments.
- *Fax:* 1–202–493–2251.
- *Mail:* Hand Delivery: U.S. DOT Docket Management System, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590–0001 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

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

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

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

SUPPLEMENTARY INFORMATION:

Outline of This Document

I. Executive Summary
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. Advance Notice of Proposed Rulemaking
C. National Transportation Safety Board Recommendations
D. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011
E. Summary of Each Topic Under Consideration
F. Integrity Verification Process Workshop
III. Analysis of Comments on the Advance Notice of Proposed Rulemaking
A. Modifying the Definition of HCA
B. Strengthening Requirements To Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs
C. Modifying Repair Criteria
D. Improving Requirements for Collecting, Validating, and Integrating Pipeline Data
E. Making Requirements Related to the Nature and Application of Risk Models More Prescriptive
F. Strengthening Requirements for Applying Knowledge Gained Through the IM Program
G. Strengthening Requirements on the Selection and Use of Assessment Methods
H. Valve Spacing and the Need for Remotely or Automatically Controlled Valves
I. Corrosion Control
J. Pipe Manufactured Using Longitudinal Weld Seams
K. Establishing Requirements Applicable to Underground Gas Storage
L. Management of Change
M. Quality Management Systems (QMS)
N. Exemption of Facilities Installed Prior to the Regulations
O. Modifying the Regulation of Gas Gathering Lines
IV. Other Proposals
V. Section-by-Section Analysis
VI. Availability of Standards Incorporated by Reference
VII. Regulatory Analysis and Notices

I. Executive Summary

A. Purpose of the Regulatory Action

PHMSA believes that the current regulatory requirements applicable to gas pipeline systems have increased the level of safety associated with the transportation of gas. Still, incidents with significant consequences and various causes continue to occur on gas pipeline systems. PHMSA has also identified concerns during inspections of gas pipeline operator programs that indicate a potential need to clarify and enhance some requirements. Based on this experience, this NPRM proposes additional safety measures to increase the level of safety for those pipelines that are not in HCAs as well as clarifications and selected enhancements to integrity management requirements to improve safety in HCAs.

On August 25, 2011, PHMSA published an Advance Notice of Proposed Rulemaking (ANPRM) to seek feedback and comments regarding the revision of the Pipeline Safety Regulations applicable to the safety of gas transmission and gas gathering pipelines. In particular, PHMSA requested comments regarding whether integrity management (IM) requirements should be changed and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements.

Subsequent to issuance of the ANPRM, the National Transportation Safety Board (NTSB) adopted its report on the San Bruno accident on August 30, 2011. The NTSB issued safety recommendations P–11–1 and P–11–2 and P–11–8 through -20 to PHMSA, and issued safety recommendations P–10–2 through -4 to Pacific Gas & Electric (PG&E), among others. Several of these NTSB recommendations related directly to the topics addressed in the August 25, 2011 ANPRM and have an impact on the proposed approach to rulemaking. Also subsequent to issuance of the ANPRM, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act) was enacted on January 3, 2012. Several of the Act's statutory requirements related directly to the topics addressed in the August 25, 2011 ANPRM and have an impact on the proposed approach to rulemaking.

Congress has authorized Federal regulation of the transportation of gas by pipeline in the Pipeline Safety Laws (49 U.S.C. 60101 *et seq.*), a series of statutes that are administered by the DOT, PHMSA. PHMSA has used that authority to promulgate comprehensive minimum safety standards for the transportation of gas by pipeline.

Congress established the current framework for regulating pipelines transporting gas in the Natural Gas Pipeline Safety Act of 1968, Public Law 90–481. That law delegated to DOT the authority to develop, prescribe, and enforce minimum Federal safety standards for the transportation of gas, including natural gas, flammable gas, or toxic or corrosive gas, by pipeline. Congress has since enacted additional legislation that is currently codified in the Pipeline Safety Laws, including:

In 1992, Congress required regulations be issued to define the term ''gathering line'' and establish safety standards for certain ''regulated gathering lines,'' Public Law 102–508. In 1996, Congress directed that DOT conduct demonstration projects evaluating the application of risk management principles to pipeline safety regulation, and

mandated that regulations be issued for the qualification and testing of certain pipeline personnel, Public Law 104–304. In 2002, Congress required that DOT issue regulations requiring operators of gas transmission pipelines to conduct risk analyses and to implement IM programs under which pipeline segments in high consequence areas (HCA) would be subject to a baseline assessment within 10 years and re-assessments at least every seven years, and required that standards be issued for assessment of pipelines using direct assessment, Public Law 107–355.

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

PHMSA plans to address several of the topics in the ANPRM in separate rulemakings because of the diverse scope and nature of several NTSB recommendations and the statutory requirements of the Act that were covered in the ANPRM. This proposed rule addresses several IM topics, including: Revision of IM repair criteria for pipeline segments in HCAs to address cracking defects, non-immediate corrosion metal loss anomalies, and other defects; explicitly including functional requirements related to the nature and application of risk models currently invoked by reference to industry standards; explicitly specifying requirements for collecting, validating, and integrating pipeline data models currently invoked by reference to industry standards; strengthening requirements for applying knowledge gained through the IM Program models currently invoked by reference to industry standards; strengthening requirements on the selection and use of direct assessment methods models by incorporating recently issued industry standards by reference; adding requirements for monitoring gas quality and mitigating internal corrosion, and adding requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys; and explicitly including requirements for management of change currently invoked by reference to industry standards. With respect to non-IM requirements, this NPRM proposes: A new ''moderate consequence areas'' definition; adding requirements for monitoring gas quality and mitigating internal corrosion; adding requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys; additional requirements for management of change, including invoking the requirements of ASME/ANSI B31.8S, Section 11; establishing repair criteria for pipeline segments located in areas not in an HCA; and requirements for verification of maximum allowable operating pressure (MAOP) in accordance with new § 192.624 and for verification of pipeline material in accordance with new section § 192.607 for certain onshore, steel, gas transmission pipelines. This includes establishing and documenting MAOP if the pipeline MAOP was established in accordance with § 192.619(c) or the pipeline meets other criteria indicating a need for establishing MAOP.

In addition, this NPRM proposes modifying the regulation of onshore gas gathering lines. The proposed rulemaking would repeal the exemption for reporting requirements for gas gathering line operators and repeal the use of API RP 80 for determining regulated onshore gathering lines and add a new definition for ''onshore production facility/operation'' and a revised definition for ''gathering lines.'' The proposed rulemaking would also extend certain part 192 regulatory requirements to Type A lines in Class 1 locations for lines 8 inches or greater. Requirements that would apply to previously unregulated pipelines meeting these criteria would be limited to damage prevention, corrosion control (for metallic pipe), public education program, maximum allowable operating pressure limits, line markers, and emergency planning.

This NPRM also proposes requirements for additional topics that have arisen since issuance of the ANPRM. These include: (1) Requiring inspections by onshore pipeline operators of areas affected by an extreme weather event such as a hurricane or flood, landslide, an earthquake, a natural disaster, or other similar event; (2) revising the regulations to allow extension of the IM 7-year reassessment interval upon written notice per Section 5 of the Act; (3) adding a requirement to report each exceedance of the MAOP that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices per Section 23 of the Act; (4) adding requirements to ensure consideration of seismicity of the area in identifying and evaluating all potential threats per Section 29 of the Act; (5) adding regulations to require safety features on launchers and receivers for in-line inspection, scraper, and sphere facilities; and (6) incorporating consensus standards into the regulations for assessing the physical condition of in-service pipelines using in-line inspection, internal corrosion direct assessment, and stress corrosion cracking direct assessment.

The overall goal of this proposed rule is to increase the level of safety associated with the transportation of gas by proposing requirements to address the causes of recent incidents with significant consequences, clarify and enhance some existing requirements, and address certain statutory mandates of the Act and NTSB recommendations.[1]

C. Costs and Benefits

Consistent with Executive Orders 12866 and 13563, PHMSA has prepared an assessment of the benefits and costs of the proposed rule as well as reasonable alternatives. PHMSA is publishing the Preliminary Regulatory Impact Analysis (PRIA) for this proposed rule simultaneously with this document, and it is available in the docket.

PHMSA estimates the total (15-year) present value of benefits from the proposed rule to be approximately $3,234 to $3,738 million[2] using a 7% discount rate ($4,050 to $4,663 million using a 3% discount rate) and the present value of costs to be approximately $597 million using a 7% discount rate ($711 million using a 3% discount rate). The table below summarizes the average annual present value benefits and costs by topic area. The majority of benefits reflect cost savings from material verification (processes to determine maximum allowable operating pressure for segments for which records are inadequate) under the proposed rule compared to existing regulations; the range in these benefits reflects different effectiveness assumptions for estimating safety benefits. Costs reflect primarily integrity verification and assessment costs (pressure tests, inline inspection, and direct assessments). The proposed gas gathering regulations account for the next largest portion of benefits and costs and primarily reflect safety provisions and associated risk reductions on previously unregulated lines.

[1] PHMSA plans to initiative separate rulemaking to address other topics included in the ANPRM and that would implement other requirements of the Act and NTSB recommendations.

[2] Range reflects uncertainty in defect failure rates for Topic Area 1.

SUMMARY OF AVERAGE ANNUAL PRESENT VALUE BENEFITS AND COSTS [1]

[Millions; 2015$]

Topic area	7% discount rate		3% discount rate	
	Benefits	Costs	Benefits	Costs
Re-establish MAOP, verify material properties, and integrity assessments outside HCAs	$196.9–$230.5	$17.8	$247.8–$288.6	$22.0
Integrity management process clarifications	n.e.	2.2	n.e.	1.3
Management of change process improvement	1.1	0.7	1.2	0.8
Corrosion control	5.5	6.3	5.9	7.9
Pipeline inspection following extreme events	0.3	0.1	0.3	0.1
MAOP exceedance reports and records verification	n.e.	0.2	n.e.	0.2
Launcher/receiver pressure relief	0.4	0.0	0.6	0.0
Gas gathering regulations	11.3	12.6	14.2	15.1
Total	215.6–249.2	39.8	270–310.8	47.4

HCA = high consequence area.
MAOP = maximum allowable operating pressure.
n.e. = not estimated.
[1] Total over 15-year study period divided by 15. Additional costs to states estimated not to exceed $1.5 million per year. Range of benefits reflects range in estimated defect failure rates.
[2] Break even value of benefits, based on the average consequences for incidents in high consequence areas, would equate to less than one incident averted over the 15-year study period.

For the seven percent discount rate scenario, approximately 13 percent of benefits are due to safety benefits from incidents averted, 82 percent represent cost savings from MAOP verification in Topic Area 1, and four percent are attributable to reductions in greenhouse gas emissions. (For the three percent discount rate scenario, these percentages are approximately 13, 83, and 3 percent, respectively.)

II. Background

A. Detailed Overview

Introduction

The significant and expected growth in the nation's production and use of natural gas 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 natural gas production and use and an aging pipeline network, improved documentation and data collection 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 thorough application of the risk-based integrity assessment, repair, and validation system known as ''integrity management'' (IM).

This proposed rulemaking advances the goals established by Congress in the 2011 Act, which are consistent with the emerging needs of the natural gas pipeline system. This proposed 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 increasingly encroach on existing pipelines. As some severe pipeline accidents have occurred in areas outside of high consequence areas (HCA) where the application of IM principles is not required, and as gas pipelines continue to experience failures from causes that IM was intended to address, this conversation is increasingly important.

This proposed 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. Further, this proposed rule establishes requirements to periodically assess and extend aspects of IM to pipeline segments in locations where the surrounding population is expected to potentially be at risk from an incident. Even though these segments are not within currently defined HCAs, they could be located in areas with significant populations where incidents could have serious consequences. This change would facilitate prompt identification and remediation of potentially hazardous defects and anomalies while still allowing operators to make risk-based decisions on where to allocate their maintenance and repair resources.

Natural Gas Infrastructure Overview

The U.S. natural gas pipeline network is designed to transport natural gas to and from most locations in the lower 48 States. Approximately two-thirds of the lower 48 States depend almost entirely on the interstate transmission pipeline system for their supplies of natural gas.[3] To envision the scope of the nation's natural gas pipeline infrastructure, it is best to consider it in three interconnected parts that together transport natural gas from the production field, where gas is extracted from underground, to its end users, where the gas is used as an energy fuel or chemical feedstock. These three parts are referred to as gathering, transmission, and distribution systems. Because this proposed rule applies only to gas gathering and transmission lines, this document will not discuss natural gas distribution infrastructure and its associated issues. Currently, there are over 11,000 miles of onshore gas gathering pipelines and 297,814 miles of onshore gas transmission pipelines throughout the U.S.[4]

Gas gathering lines are pipelines used to transport natural gas from production sites to central collection points, which are often gas treatment plants where pipeline-quality gas is separated from petroleum liquids and various impurities. Historically, these lines were of smaller diameters than gas transmission lines and operated at lower pressures. However, due to changing demand factors, some gathering lines are being constructed with diameters equal to or larger than typical transmission lines and are being operated at much higher pressures.

Transmission pipelines primarily transport natural gas from gas treatment

[3] U.S. Department of Energy, ''Appendix B: Natural Gas,'' *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG–28, April 2015.

[4] US DOT Pipeline and Hazardous Materials Safety Administration Data as of 9/25/2015.

plants and gathering systems to bulk customers, local distribution networks, and storage facilities. Transmission pipelines are typically made of steel and can range in size from several inches to several feet in diameter. They can operate over a wide range of pressures, from relatively low (200 pounds per square inch) to over 1,500 pounds per square inch gage (psig). They can operate within the geographic boundaries of a single State, or span hundreds of miles, crossing one or more State lines.

Regulatory History

PHMSA and its State partners regulate pipeline safety for jurisdictional [5] gas gathering, transmission, and distribution systems under minimum Federal safety standards authorized by statute [6] and codified in the Pipeline Safety Regulations at 49 CFR parts 190–199.

Federal regulation of gas pipeline safety began in 1968 with the creation of the Office of Pipeline Safety and their subsequent issuance of interim minimum Federal safety standards for gas pipeline facilities and the transportation of natural and other gas in accordance with the Natural Gas Pipeline Safety Act of 1968 (Pub. L. 90–481). These Federal safety standards were upgraded several times over the following decades to address different aspects of natural gas transportation by pipeline, including construction standards, pipeline materials, design standards, class locations, corrosion control, and maximum allowable operating pressure (MAOP).

These original 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.

In response to a hazardous liquid incident in Bellingham, WA, in 1999 that killed 3 people and a gas transmission incident in Carlsbad, NM, in 2000 that killed 12, IM regulations for gas transmission pipelines were finalized in 2004.[7] The primary goal of the 2004 IM regulations was to provide a structure to operators for focusing their resources on improving pipeline integrity in the areas where a failure would have the greatest impact on public safety. Further objectives included accelerating the integrity assessment of pipelines in HCAs, improving IM systems within companies, improving the government's ability to review the adequacy of integrity programs and plans, thus providing increased public assurance in pipeline safety.

The IM regulations specify how pipeline operators must conduct comprehensive analyses to identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines in HCAs, which are typically areas where population is highly concentrated. Currently, approximately 7 percent of onshore gas transmission pipeline mileage is located in HCAs. PHMSA and state inspectors review operators' written IM programs and associated records to verify that the operators have used all available information about their pipelines to assess risks and take appropriate actions to mitigate those risks.

Since the implementation of the IM regulations more than 10 years ago, many factors have changed. Most importantly, sweeping changes in the natural gas industry have caused significant shifts in supply and demand, and the nation's relatively safe but aging pipeline network faces increased pressures from these changes as well as from the increased exposure caused by a growing and geographically dispersing population. 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 outdated construction methods or materials. Some severe pipeline accidents have occurred in areas outside HCAs where the application of IM principles is not required. Gas pipelines continue to experience failures from causes that IM was intended to address, such as corrosion, and the measures currently in use have not always been effective in identifying and preventing these causes of pipeline damage.

There is a pressing need for an improved strategy to protect the safety and integrity of the nation's pipeline system. Following a significant pipeline incident in 2010 at San Bruno, CA, in which 8 people died and more than 50 people were injured, Congress, the National Transportation Safety Board (NTSB), and the Government Accountability Office (GAO) charged PHMSA with improving IM. Comments from a 2011 advanced notice of proposed rulemaking (ANPRM) suggested there were many common-sense improvements that could be made to IM, as well as a clear need to extend certain IM provisions to pipelines not now covered by the IM regulations. A large portion of the transmission pipeline industry has voluntarily committed to extending certain IM provisions to non-HCA pipe, which clearly underscores the common understanding of the need for this strategy.

Through this proposed rule, PHMSA is taking action to deliver a comprehensive strategy to improve gas transmission pipeline safety and reliability, through both immediate improvements to IM and a long-range review of risk management and information needs, while also accounting for a changing landscape and a changing population.

Supply Changes

The U.S. natural gas industry has undergone changes of unprecedented magnitude and pace, increasing production by 33 percent between 2005 and 2013, from 19.5 trillion cubic feet per year to 25.7 trillion cubic feet per year.[8] Driving these changes has been a shift towards the production of ''unconventional'' natural gas supplies using improved technology to extract gas from low permeability shales. The increased use of directional drilling and improvements to a long-existing industrial technique—hydraulic fracturing, which began as an experiment in 1947—made the recovery of unconventional natural gas easier and economically viable. This shift in production has decreased prices and spurred tremendous increases in the use of natural gas.

While conventional natural gas production in the U.S. has fallen over the past decade by about 14 billion cubic feet per day, overall natural gas production has grown due to increased unconventional shale gas production. In 2004, unconventional shale gas accounted for about 5 percent of the total natural gas production in the U.S. Since then, unconventional shale gas

[5] Typically, onshore pipelines involved in the ''transportation of gas''—see 49 CFR 192.1 and 192.3 for detailed applicability.

[6] Title 49, United States Code, Subtitle VIII, Pipelines, Sections 60101, *et. seq.*

[7] [68 FR 69778, Dec. 15, 2003] 49 CFR part 192 [Docket No. RSPA–00–7666; Amendment 192–95] Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines).

[8] U.S. Department of Energy, ''Appendix B: Natural Gas,'' *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG–2, April 2015.

production has increased more than tenfold from 2.7 Bcf/d to about 35.0 Bcf/d in 2014 [9] and now accounts for about half of overall gas production in the U.S.[10]

This increase in unconventional natural gas production shifted production away from traditional gas-rich regions towards onshore shale gas regions. In 2004, the Gulf of Mexico produced about 20 percent of the nation's natural gas supply, but by2013, that number had fallen to 5 percent. During that same time, Pennsylvania's share of production grew from 1 percent to 13 percent. An analysis conducted by the Department of Energy's (DOE) Office of Energy Policy and Systems Analysis projects that the most significant increases in production through 2030 will occur in the Marcellus and Utica Basins in the Appalachian Basin,[11] which will continue to fuel growth in natural gas production from current levels of 66.5 Bcf/d to more than 93.5 Bcf/d.[12]

Demand Changes

The recent increase in domestic natural gas production has led to decreased gas price volatility and lower average prices.[13] In 2004, the outlook for natural gas production and demand growth was weak. Monthly average spot prices at Henry Hub [14] were high, fluctuating between $4 per million British thermal units (Btu) and $7 per million Btu. Prices rose above $11 per million Btu for several months in both 2005 and 2008.[15] Since 2008, after production shifted to onshore unconventional shale resources, and price volatility fell away following the Great Recession, natural gas has traded between about $2 per million Btu and $5 per million Btu.[16]

These historically low prices for this commodity are fueling tremendous consumption growth and changes in markets and spatial patterns of consumption. A shift towards natural gas-fueled electric power generation is helping to serve the needs of the nation's growing population while helping reduce greenhouse gas emissions, and American industries are taking advantage of cheap energy by investing in onshore production capacity, while also exploring economic opportunities for international energy export.

Plentiful domestic natural gas supply and comparatively low natural gas prices have changed the economics of electric power markets.[17] Further, new environmental standards at the local, state, regional, and Federal levels have encouraged switching to fuels with lower emissions profiles, including natural gas and renewables. U.S. natural gas consumption for power generation grew from 15.8 billion cubic feet per day (Bcf/d) in 2005 to 22.2 Bcf/d in 2013, and demand is projected to increase by another 8.9 Bcf/d by 2030.[18] Net gas-fired electricity generation increased 73 percent nationally from 2003 to 2013, and natural gas-fired power plants accounted for more than 50 percent of new utility-scale generating capacity added in 2013. To accommodate continued future growth in natural gas-fueled power, changes in pipeline infrastructure will be needed, including reversals of existing pipelines; additional lines to gas-fired generators; looping of the existing network, where pipelines are laid parallel to one another along a single right-of-way to increase capacity; and potentially new pipelines as well.

Further, the increased availability of low-cost natural gas has brought jobs back to American soil, and increasing investment in projects designed to take advantage of the significant increase in supplies of low-cost gas available in the U.S. suggests this trend will continue.[19] Moreover, low domestic prices and high international prices have made natural gas export increasingly attractive to American businesses. The Federal Energy Regulatory Commission, as of September 2015, estimated U.S. LNG prices at $2.25–$2.41 per million Btu, while prices in areas of Asia, Europe, and South America ranged from $6.30 to $7.62 per million Btu.[20] Due to high capital investment barriers and coordination difficulties between pipeline shippers, the maritime shipping industry, and pipeline operators, there are not enough ships and processing facilities to transport enough LNG to equalize prices. Taking advantage of these price differentials, liquefied natural gas exporting terminals in the U.S. and British Columbia, Canada, are projected to demand between 5.1 Bcf/d and 8.3 Bcf/d of gas by 2030.[21]

Increasing Pressures on the Existing Pipeline System Due to Supply and Demand Changes

Despite the significant increase in domestic gas production, the widespread distribution of domestic gas demand, combined with significant flexibility and capacity in the existing transmission system, mitigates the level of pipeline expansion and investment required to accommodate growing and shifting demand. Some of the new gas production is located near existing or emerging sources of demand, which reduces the need for additional natural gas pipeline infrastructure. In many instances where new natural gas pipelines are needed, the network is being expanded by participants pursuing lowest-cost options to move product to market—often making investments to enhance network capacity on existing lines rather than increasing coverage through new infrastructure. Where this capacity is not increasing via additional mileage, it is increasing through larger pipeline diameters or higher operating pressures. In short, the nation's existing, and in many cases, aging, pipeline system is facing the full brunt of this dramatic increase in natural gas supply and the shifting energy needs of the country.

The U.S. Energy Information Administration estimates that between 2004 and 2013, the natural gas industry spent about $56 billion expanding the natural gas pipeline network. Between 2008 and 2013, pipeline capacity additions totaled more than 110 Bcf/d.[22] Despite this increase in capacity, gas transmission mileage decreased from 299,358 miles in 2010 to 298,287 miles in 2013.

Building new infrastructure, or replacing and modernizing old infrastructure, is expensive and requires a long lead-time for planning. Frequently, the most inexpensive way to move new production to demand centers is by using available existing infrastructure. For several reasons, the U.S.'s extensive pre-existing gas network is currently underutilized: (1) Pipelines are long-lived assets that reflect historic supply and demand trends; (2) pipelines often are sized to meet high initial production levels and

[9] *Id.,* at NG–7.

[10] *Id.*

[11] *Id.,* at NG–6.

[12] *Id.*

[13] *Id.,* at NG–11.

[14] Henry Hub is a Louisiana natural gas distribution hub where conventional Gulf of Mexico natural gas can be directed to gas transmission lines running to different parts of the country. Gas bought and sold at the Henry hub serves as the national benchmark for U.S. natural gas prices. (*Id.,* at NG–29, NG–30).

[15] Energy Information Administration, Natural Gas Spot and Futures Prices, *http://www.eia.gov/dnav/ng/ng_pri_fut_s1_m.htm,* retrieved 14 October 2015.

[16] *Id.,* at NG–11.

[17] *Id.,* at NG–9.

[18] *Id.*

[19] *Id.,* at NG–10.

[20] *https://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf.*

[21] U.S. Department of Energy, ''Appendix B: Natural Gas,'' *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG–11, April 2015.

[22] *Id.,* at NG–31.

have excess long-term capacity due to changing economics; and (3) pipelines that were built specifically to provide gas to residential and commercial consumers in cold-weather regions but not for power generation are often under-utilized during off-peak seasons.

In cases where utilization of the existing pipeline network is high, the next most cost-effective solution is to add capacity to existing lines via compression. While this is technically a form of infrastructure investment, it is less costly, faster, and simpler for market participants in comparison to building a new pipeline. Adding compression, however, may raise average pipeline operating pressures, exposing previously hidden defects.

Developers also recognize that building new pipelines is challenging due to societal fears and cost, so new pipelines are typically designed in such a way that they can handle additional capacity if needed. In New England, new pipeline projects have been proposed to address pending supply constraints and higher prices. However, public acceptance presents a substantial challenge to natural gas pipeline development. Investments and proposals to pay for new natural gas transmission pipeline capacity and services often face significant challenges in determining feasible rights of way and developing community support for the projects.

Data Challenges

Because there is so much emphasis on using the existing pipeline system to meet the country's energy needs, it is increasingly important for that system to be safe and efficient. In order to keep the public safe and to assure the nation's energy security, operators and regulators must have an intimate understanding of the threats to and operations of the entire pipeline system.

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. Ironically, the comparatively positive safety record of the nation's pipeline system to date makes it harder to quantify some of these gaps. Over the 20-year period of 1995–2014, transmission facilities accounted for 42 fatalities and 174 injuries, or about one-seventh of the total fatalities and injuries on the nation's natural gas pipeline system.[23] Over the 4-year period of 2011–2014, there was only 1 transmission-related fatality. Fortunately, there have been only limited ''worst-case scenarios'' to evaluate for cost/benefit analysis of measures to improve safety, so there are limited bases for projecting the possible impacts of low-probability, high-consequence events.

On September 9, 2010, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline owned and operated by the Pacific Gas and Electric Company ruptured in a residential area of San Bruno, California. The rupture produced a crater about 72 feet long by 26 feet wide. The section of pipe that ruptured, which was about 28 feet long and weighed about 3,000 pounds, was found 100 feet south of the crater. The natural gas that was released subsequently ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.

The San Bruno incident exposed several problems in the way data on pipeline conditions is collected and managed, showing that many operators have inadequate records regarding the physical and operational characteristics of their pipelines. Many of these records are necessary for the correct setting and validation of MAOP, which is critically important for providing an appropriate margin of safety to the public.

Much of operator and PHMSA's data is obtained through testing and inspection under IM requirements. However, this testing can be expensive, and the approaches to obtaining data that are most efficient over the long term may require significant upfront costs to modernize pipes and make them suitable for automated inspection. As a result, there continue to be data gaps that make it hard to fully understand the risks to and the integrity of the nation's pipeline system.

To assess a pipeline's integrity, operators generally choose between three methods of testing a pipeline: Inline inspection (ILI), pressure testing, and direct assessment (DA). There is a marked difference in the distribution of assessment methods between interstate and intrastate pipelines. In 2013, we estimate that about two-thirds of interstate pipeline mileage was suitable for in-line inspection, compared to only about half of intrastate pipeline mileage. Because a larger percentage of intrastate pipelines are unable to accommodate ILI tools, intrastate operators use more pressure testing and DA than interstate operators.

ILIs are performed 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 prevent excessive 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.

Pressure tests are typically used by pipeline operators 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 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. Areas that are likely to have suffered from corrosion are subsequently excavated and examined. DA can be prohibitively expensive to use unless targeting specific locations, which may not give an accurate representation of the condition of lengths of entire pipeline segments.

Ongoing research and industry response to the ANPRM[24] appear to indicate that ILI and spike hydrostatic pressure testing is more effective than DA for identifying pipe conditions that are related to stress corrosion cracking defects. 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, occasional disruptions in service, and substantial methane emissions due to the routine evacuation of natural gas from pipelines prior to tests. Further, many operators prefer not to use hydrostatic pressure tests because it can potentially be a

[23] PHMSA, Pipeline Incident 20-Year Trends, *http://www.phmsa.dot.gov/pipeline/library/data-stats/pipelineincidenttrends.*

[24] ''Pipeline Safety: Safety of Gas Transmission Pipelines—Advanced Notice of Proposed Rulemaking,'' 76 FR 5308; August 25, 2011.

destructive method of testing.[25] ILI testing can obtain data along a pipeline not otherwise obtainable via other assessment methods, although this method also has certain limitations.

In this proposed rulemaking, PHMSA would expand the range of permissible assessment methods while imposing new requirements to guide operators' selection of appropriate methods. Allowing alternatives to hydrostatic testing (including ILI technologies), combined with further research and development to make ILI testing more accurate, could help to drive innovation in pipeline integrity testing technologies. This could eventually lead to improved safety and system reliability through better data collection and assessment.

Increased and Changing Use, Coupled With Age, Exposure to Weather, and Other Factors Can Increase the Risk of Pipeline Incidents

While the existing pipeline network's capacity is expected to bear the brunt of the increasing demand for natural gas in this country, due in part due to the location of new gas resources, new production patterns are causing unique concerns for some pipeline operators. The significant growth of production outside the Gulf Coast region—especially in Pennsylvania and Ohio—is causing a reorientation of the nation's transmission pipeline network. The most significant of these changes will require reversing flows on pipelines to move Marcellus and Utica gas to the southeastern Atlantic region and the Midwest.

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 natural gas transmission 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 gas transmission lines. In response to this phenomenon, PHMSA issued an Advisory Bulletin notifying operators of the potentially significant impacts such changes may have on the integrity of a pipeline.[26]

Further, the rise of shale gas production is altering not just the extent, but also the characteristics of the nation's gas gathering systems. Gas fields are being developed in new geographic areas, thus requiring entirely new gathering systems and expanded networks of gathering lines. Producers are employing gathering lines with diameters as large as 36 inches and maximum operating pressures up to 1480 psig, far exceeding historical design and operating pressure of typical gathering lines and making them similar to large transmission lines. Most of these new gas gathering lines are unregulated, and PHMSA does not collect incident data or report annual data on these unregulated lines.

However, PHMSA is aware of incidents that show gathering lines are subject to the same sorts of failures common to other pipelines that the agency does regulate. For example, on November 14, 2008, three homes were destroyed and one person was injured when a gas gathering line ruptured in Grady County, OK. On June 8, 2010, two workers died when a bulldozer struck a gas gathering line in Darrouzett, TX, and on June 29, 2010, three men working on a gas gathering line in Grady County, OK, were injured when it ruptured. The dramatic expansion in natural gas production and changes in typical gathering line characteristics require PHMSA to review its regulatory approach to gas gathering pipelines to address new safety and environmental risks.

In addition to demands placed on the nation's pipeline system due to increased and changing use, there are many other factors—including recurring issues that IM was initially developed to address—that affect the integrity of the nation's pipelines.

Data indicate that some pipelines continue to be vulnerable to issues stemming from outdated construction methods or materials. Much of the older line pipe in the nation's gas transmission infrastructure was made before the 1970s using techniques that have proven to contain latent defects due to the manufacturing process. For example, line pipe manufactured using low frequency electric resistance welding is susceptible to seam failure. Because these manufacturing techniques were used during the time before the Federal gas regulations were issued, many of those pipes are subsequently exempt from certain regulations, most notably the requirement to pressure test the pipeline or otherwise verify its integrity to establish MAOP. A substantial amount of this type of pipe is still in service. 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. The NTSB's investigation of the San Bruno incident determined that the pipe failed due to a similar defect. Additionally, between 2010 and 2014, fifteen other reportable incidents were attributed to seam failures, resulting in over $8 million of property damage.

The nation's pipeline system also faces a greater risk from failure due to extreme weather events such as hurricanes, floods, mudslides, tornadoes, and earthquakes. A 2011 crude oil spill into the Yellowstone River 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. In October 1994, flooding along the San Jacinto River led to the failure of eight hazardous liquid pipelines and also undermined a number of other pipelines. The escaping products were ignited, leading to smoke inhalation and burn injuries of 547 people. 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 $104M from these incidents. 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.

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 natural gas transmission pipelines and ensure public confidence.

Challenges to Modernization and Historical Problems Underscore the Need for a Clear Strategy To Protect the Safety and Integrity of the Nation's Pipeline System

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. The objectives of IM are to accelerate and improve the quality of integrity assessments, promote more rigorous and systematic management of integrity, strengthen oversight, and increase public confidence. On the operator level, an IM program consists of multiple

[25] National Transportation Safety Board, ''Pacific Gas and Electric Company; Natural Gas Transmission Pipeline Rupture and Fire; San Bruno, California; September 9, 2010,'' *Pipeline Accident Report NTSB/PAR–11–01,* Page 96, 2011.

[26] ''Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes, and Conversion to Service,'' *ADB PHMSA–2014–0040,* 79 FR 56121; September 18, 2014.

components, including adopting procedures and processes to identify HCAs, 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.

The initial definition for HCAs was finalized on August 6, 2002,[27] providing concentrations of populations with corridors of protection spanning 300, 660, or 1,000 feet, depending on the diameter and MAOP of the particular pipeline.[28] In a later NPRM,[29] PHMSA proposed changes to the definition of a HCA by introducing the concept of a covered segment, which PHMSA defined as the length of gas transmission pipeline that could potentially impact an HCA.[30] Previously, only distances from the pipeline centerline related to HCA definitions. PHMSA also proposed using Potential Impact Circles, Potential Impact Zones, and Potential Impact Radii (PIR) to identify covered segments instead of a fixed corridor width. The final Gas Transmission Pipeline Integrity Management Rule, incorporating the new HCA definition, was issued on December 15, 2003.[31]

The incident at San Bruno in 2010 motivated a comprehensive reexamination of gas transmission pipeline safety. Congress responded to concerns in light of the San Bruno incident by passing the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which directed the DOT to reexamine many of its safety requirements, including the expansion of IM regulations for transmission pipelines.

Further, both the NTSB and the GAO issued several recommendations to PHMSA to improve its IM program and pipeline safety. The NTSB noted, in a 2015 study,[32] that IM requirements have reduced the rate of failures due to deterioration of pipe welds, corrosion, and material failures. However, pipeline incidents in high-consequence areas due to other factors increased between 2010 and 2013, and the overall occurrence of gas transmission pipeline incidents in high-consequence areas has remained stable. The NTSB also found many types of basic data necessary to support comprehensive probabilistic modeling of pipeline risks are not currently available.

Many of these mandates and recommendations caused PHMSA to evaluate whether IM system requirements, or elements thereof, should be expanded beyond HCAs to afford protection to a larger percentage of the nation's population. Additionally, several of these mandates and recommendations asked PHMSA to enhance the existing IM regulations by addressing MAOP verification, inadequate operator records, legacy pipe issues, and inadequate integrity assessments. Further, PHMSA was charged with reducing data gaps and improving data integration, considering the regulatory framework for gas gathering systems, and deleting the ''grandfather clause'' to require all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic spike pressure test. This proposed rule addresses several of the recommendations from the 2015 study including P–15–18 (IM–ILI capability), P–15–20 (IM–ILI tools), P–15–21 (IM–Direct Assessments), and P–21 (IM–Data Integration).

PHMSA Is Delivering a Comprehensive Strategy To Protect the Nation's Pipeline System While Accounting for a Changing Landscape and a Changing Population

To address these statutory mandates, the post-San Bruno NTSB and GAO recommendations, and other pipeline safety mandates, PHMSA posed a series of questions to the public in the context of an August 2011 ANPRM titled ''Pipeline Safety: Safety of Gas Transmission Pipelines'' (PHMSA–2011–0023). In that document, PHMSA asked whether the regulations governing the safety of gas transmission pipelines needed changing. In particular, PHMSA asked whether IM requirements should be changed, including through adding more prescriptive language in some areas, and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. Among the specific issues PHMSA considered concerning IM requirements were whether the definition of an HCA should be revised, and whether additional restrictions should be placed on the use of specific pipeline assessment methods. In the ANPRM, PHMSA also considered changes to non-IM requirements, including valve spacing and installation, corrosion control, and whether regulations for gathering lines needed to be modified.

PHMSA received 103 comments in response to the ANPRM, which are summarized in more detail later in this document. Feedback from the ANPRM helped to identify a series of common-sense improvements to IM, including improvements to assessment goals such as integrity verification, MAOP verification, and material documentation; clarified repair criteria; clarified protocol for identifying threats, risk assessments and management, and prevention and mitigation measures; expanded and enhanced corrosion control; requirements for inspecting pipelines after incidents of extreme weather; and new guidance on how to calculate MAOP in order to set operating parameters more accurately and predict the risks of an incident.

Many of these aspects of IM have been an integral part of PHMSA's expectations since the inception of the IM program. As specified in the first IM rule, PHMSA expects operators to start with an IM framework, evolve a more detailed and comprehensive IM program, and continually improve their IM programs as they learn more about the IM process and the material condition of their pipelines through integrity assessments. This NPRM's proposals regarding operators' processes for implementing IM reflect PHMSA's expectations regarding the degree of progress operators should be making, or should have made, during the first 10 years of IM program implementation.

To address issues involving the increased risk posed by larger-diameter, higher-pressure gathering lines, PHMSA is proposing to issue requirements for certain currently unregulated gas gathering pipelines that are intended to prevent the most frequent causes of failure—corrosion and excavation damage—and to improve emergency response preparedness. Minimum Federal safety standards would also bring an appropriate level of consistency to the current mix of regulations that differ from state to state.

[27] ''Pipeline Safety: High Consequence Areas for Gas Transmission Pipelines,'' *Final rule,* 67 FR 50824; August 6, 2002.

[28] The influence of the existing class location concept on the early definition of HCAs is evident from the use of class locations themselves in the definition, and the use of fixed 660 ft. distances, which corresponds to the corridor width used in the class location definition. This concept was later significantly revised, as discussed later, in favor of a variable corridor width (referred to as the Potential Impact Radius) based on case-specific pipe size and operating pressure.

[29] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines),'' *Notice of Proposed Rulemaking,* 68 FR 4278; January 28, 2003.

[30] HCA and PIR definitions are in 49 CFR 192.903.

[31] ''Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines),'' *Final rule,* 68 FR 69778; December 15, 2003.

[32] National Transportation Safety Board, ''Safety Study: Integrity Management of Gas Transmission Pipelines in High Consequence Areas,'' *NTSB SS–15/01,* January 27, 2015.

PHMSA believes these proposed changes will improve the safety and protection of pipeline workers, the public, property, and the environment by improving the detection and remediation of unsafe conditions, ensuring that certain currently unregulated pipelines are subject to appropriate regulatory oversight, and speeding mitigation of adverse effects of pipeline failures. In addition to safety benefits, the rule is expected to improve the performance and extend the economic life of critical pipeline infrastructure that transports domestically produced natural gas energy, thus supporting national economic and security energy objectives.

Looking at Risk Beyond HCAs

In addition to the common sense improvements to IM, responses to the ANPRM reinforced the importance of carefully reconsidering the scope of areas covered by IM. While PHMSA's IM program manages risks primarily by focusing oversight on areas with the greatest population density, responses to the ANPRM highlight the imperative of protecting the safety of communities throughout the country in light of a changing landscape of production, consumption, and product movement that merits a refreshed look at the current scope of IM coverage.

In the 2011 Act, Congress required PHMSA to have pipeline operators conduct a records verification to ensure that their records accurately reflect the physical and operational characteristics of pipelines in certain HCAs and class locations, and to confirm the established MAOP of the pipelines. The results of that action indicate that problems similar to the contributing factors of the San Bruno incident are more widespread than previously believed, affecting both HCA and non-HCA segments. This indicates that a rupture on the scale of San Bruno, with the potential to affect populations, the environment, or commerce, could occur elsewhere on the nation's pipeline system.

In fact, devastating incidents have occurred outside of HCAs in rural areas where populations are sparse but present. On August 19, 2000, a 30-inch-diameter gas transmission pipeline ruptured adjacent to the Pecos River near Carlsbad, NM. The released gas ignited and burned for 55 minutes. Twelve persons who were camping under a concrete-decked steel bridge that supported the pipeline across the river were killed, and their vehicles were destroyed. Two nearby steel suspension bridges for gas pipelines crossing the river were damaged extensively.

On December 14, 2007, two men were driving in a pickup truck on Interstate 20 near Delhi, LA, when a 30-inch gas transmission pipeline ruptured. One of the men was killed, and the other was injured.

On December 11, 2012, a 20-inch-diameter gas transmission line ruptured in a sparsely populated area about 106 feet west of Interstate 77 (I–77) in Sissonville, WV. An area of fire damage about 820 feet wide extended nearly 1,100 feet along the pipeline right-of-way. Three houses were destroyed by the fire, and several other houses were damaged. Reported losses, repairs, and upgrades from this incident totaled over $8.5 million, and major transportation delays occurred. I–77 was closed in both directions because of the fire and resulting damage to the road surface. The northbound lanes were closed for about 14 hours, and the southbound lanes were closed for about 19 hours while the road was resurfaced, causing delays to both travelers and commercial shipping.

Because the nation's population is growing, moving, and dispersing, population density is a changing measure, and we need to be prepared for further shifts in the coming decades. The current definition of an HCA uses building density as a proxy for approximating the presence of communities and surrounding infrastructure. This can be a meaningful metric for prioritizing implementation of safety and risk management protocols for areas where an accident would have the greatest likelihood of putting human life in danger, but it is not necessarily an accurate reflection of whether an incident will have a significant impact on people. Requiring assessment and repair criteria for pipelines that, if ruptured, could pose a threat to areas where any people live, work, or congregate would improve public safety and would improve public confidence in the nation's natural gas pipeline system.

Feedback from industry indicated that some pipeline operators are already moving towards expanding the protections of IM beyond HCAs. In 2012, the Interstate Natural Gas Association of America (INGAA) issued a ''Commitment to Pipeline Safety,'' [33] underscoring its efforts towards a goal of zero incidents, a committed safety culture, a pursuit of constant improvement, and applying IM principles on a system-wide basis. INGAA divides the commitment into four stages:

- Stage 1—INGAA members will complete an initial assessment using some degree of IM on their pipelines, covering 90% of the population living, working, or congregating along INGAA member pipelines, by the end of 2012. This represents roughly 64% of INGAA member pipeline mileage, including the 4% of pipelines that are in HCAs.
- Stage 2—By 2020, INGAA members will consistently and comprehensively apply IM principles to those pipelines.
- Stage 3—By 2030, INGAA members will apply IM principles to pipelines, extending IM protection to 100% of the population living along INGAA member pipelines. This stage would cover roughly 16% of pipeline mileage, bringing the total coverage by 2030 to approximately 80% of INGAA's pipeline mileage.
- Stage 4—Beyond 2030, INGAA members will apply IM principles to the remaining 20% of pipeline mileage where no population resides.

To accomplish this commitment, INGAA's members are performing actions that include applying risk management beyond HCAs; raising the standards for corrosion management; demonstrating ''fitness for service'' on pre-regulation pipelines; and evaluating, refining, and improving operators' ability to assess and mitigate safety threats. Ultimately, these actions aim to extend protection to people who live near pipelines but not within defined HCAs.

INGAA's commitment and other stakeholder feedback on this issue have triggered an important exchange about measuring the risks that exist in less-densely populated areas and the impacts of expanding greater protections to those areas. If constant improvement and zero incidents are goals for pipeline operators, INGAA's plan to extend and prioritize IM assessments and principles to all parts of their pipeline networks that are located near any concentrations of population is an effective way to achieve those goals. Such an approach is needed to help clarify vulnerabilities and prioritize improvements, and this proposed rulemaking takes important steps forward towards developing such an approach.

[33] Letter from Terry D. Boss, Senior Vice President of Environment, Safety and Operations to Mike Israni, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, dated January 20, 2012, ''*Safety of Gas Transmission Pipelines,* Docket No. PHMSA–2011–0023.'' INGAA represents companies that operate approximately 65 percent of the gas transmission pipelines, but INGAA does not represent all pipeline operators subject to 49 CFR part 192.

The question then, is how to implement risk management standards that most accurately target the safety of communities, while also providing sufficient ability to prioritize areas of greatest possible risk and/or impact. Addressing that question has been, and remains, an important part of this proposed rule, recognizing that the answer will remain fluid based on factors that continue to change.

Given INGAA's commitment, feedback from the ANPRM, the results of incident investigations, and IM considerations, PHMSA has determined it is appropriate to improve aspects of the current IM program and codify requirements for additional gas transmission pipelines to receive integrity assessments on a periodic basis to monitor for, detect, and remediate pipeline defects and anomalies. In addition, in order to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, while minimizing the cost of identifying such locations, PHMSA proposes to base the requirements for identifying those locations on processes already being implemented by pipeline operators and that protect people on a risk-prioritized basis.

Establishing integrity assessment requirements and associated repair conditions for non-HCA pipe segments is important for providing safety to the public. Although those segments are not within defined HCAs, they will usually be located in populated areas, and pipeline accidents in these areas may cause fatalities, significant property damage, or disrupt livelihoods. This rulemaking proposes a newly defined moderate consequence area (MCA) to identify additional non-HCA pipeline segments that would require integrity assessments, thus assuring timely discovery and repair of pipeline defects in MCA segments. These changes would ensure prompt remediation of anomalous conditions that could potentially impact people, property, or the environment, and commensurate with the severity of the defects, while at the same time allowing operators to allocate their resources to HCAs on a higher-priority basis. INGAA's commitment and PHMSA's MCA definition are comparable, which shows a common understanding of the importance of this issue and a path towards a solution.

B. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an Advance Notice of Proposed Rulemaking (ANPRM) to seek public comments regarding the revision of the Pipeline Safety Regulations applicable to the safety of gas transmission pipelines. In particular, PHMSA requested comments regarding whether integrity management (IM) requirements should be changed and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. The ANPRM may be viewed at *http://www.regulations.gov* by searching for Docket ID PHMSA–2011–0023. As mentioned above, pursuant to the related issues raised by the NTSB recommendations and statutory requirements of the Act, PHMSA is issuing separate rulemaking for several of the topics in the ANPRM. These topics are so designated in the following list. Specifically, the ANPRM sought comments on the following topics:

A. Modifying the Definition of HCA (to be addressed in separate rulemaking),

B. Strengthening Requirements to Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs (partially addressed in separate rulemaking—aspects related to Remote Control Valves and Leak Detection will be addressed in separate rulemaking, other aspects are being addressed in this NPRM),

C. Modifying Repair Criteria,

D. Improving Requirements for Collecting, Validating, and Integrating Pipeline Data,

E. Making Requirements Related to the Nature and Application of Risk Models More Prescriptive,

F. Strengthening Requirements for Applying Knowledge Gained Through the IM Program,

G. Strengthening Requirements on the Selection and Use of Assessment Methods,

H. Valve Spacing and the Need for Remotely or Automatically Controlled Valves (to be addressed in separate rulemaking),

I. Corrosion Control,

J. Pipe Manufactured Using Longitudinal Weld Seams,

K. Establishing Requirements Applicable to Underground Gas Storage (to be considered for separate rulemaking),

L. Management of Change,

M. Quality Management Systems (QMS) (to be considered for separate rulemaking),

N. Exemption of Facilities Installed Prior to the Regulations,

O. Modifying the Regulation of Gas Gathering Lines.

A summary of comments and responses to those comments are provided later in the document.

C. National Transportation Safety Board Recommendations

On August 30, 2011, following the issuance of the ANPRM, the NTSB adopted its report on the gas pipeline accident that occurred on September 9, 2010, in San Bruno, California. On September 26, 2011, the NTSB issued safety recommendations P–11–8 through –20 to PHMSA, and issued safety recommendations P–10–2 through –4 to Pacific Gas & Electric (PG&E), among others. The NTSB made these recommendations following its investigation of the tragic September 9, 2010 natural gas pipeline rupture in the city of San Bruno, California. Several of the NTSB recommendations related directly to the topics addressed in the August 25, 2011 ANPRM and impacted the proposed approach to rulemaking. The potentially impacted topics and the related NTSB recommendations include, but are not limited to:

- Topic B—Strengthening Requirements to Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs. NTSB Recommendation P–11–10: ''*Require that all operators of natural gas transmission and distribution pipelines equip their supervisory control and data acquisition systems with tools to assist in recognizing and pinpointing the location of leaks, including line breaks; such tools could include a real-time leak detection system and appropriately spaced flow and pressure transmitters along covered transmission lines.*''
- Topic D—Improving Requirements for Collecting, Validating, and Integrating Pipeline Data. NTSB Recommendation P–11–19: ''*(1) Develop and implement standards for integrity management and other performance-based safety programs that require operators of all types of pipeline systems to regularly assess the effectiveness of their programs using clear and meaningful metrics, and to identify and then correct deficiencies; and (2) make those metrics available in a centralized database.*''
- Topic G—Strengthening Requirements on the Selection and Use of Assessment Methods. NTSB Recommendation P–11–17: ''*Require that all natural gas transmission pipelines be configured so as to accommodate in-line inspection tools, with priority given to older pipelines.*''
- Topic H—Valve Spacing and the Need for Remotely or Automatically Controlled Valves. NTSB Recommendation P–11–11: ''*Amend Title 49 Code of Federal Regulations Section 192.935(c) to directly require that automatic shutoff valves or remote*

control valves in high consequence areas and in class 3 and 4 locations be installed and spaced at intervals that consider the population factors listed in the regulations.''

• Topic J—Pipe Manufactured Using Longitudinal Weld Seams. NTSB Recommendation P–11–15: ''*Amend Title 49 Code of Federal Regulations Part 192 of the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure.*''

• Topic N—Exemption of Facilities Installed Prior to the Regulations. NTSB Recommendation P–11–14: *Amend title 49 Code of Federal Regulations 192.619 to repeal exemptions from pressure test requirements and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.*''

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

Also subsequent to issuance of the ANPRM, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act) was enacted on January 3, 2012. Several of the Act's statutory requirements relate directly to the topics addressed in the August 25, 2011 ANPRM. The related topics and statutory citations include, but are not limited to:

○ Section 5(e)—Allow periodic reassessments to be extended for an additional 6 months if the operator submits sufficient justification.

○ Section 5(f)—Requires regulations issued by the Secretary, if any, to expand integrity management system requirements, or elements thereof, beyond high-consequence areas.

○ Section 21—Regulation of Gas (and Hazardous Liquid) Gathering Lines

○ Section 23—Testing regulations to confirm the material strength of previously untested natural gas transmission pipelines.

○ Section 29—Consider seismicity when evaluating pipeline threats.

E. Summary of Each Topic Under Consideration

This NPRM proposes new requirements and revisions to existing requirements to address topics discussed in the ANPRM, including some topics from the Act and the NTSB recommendations. Each topic area discussed in the ANPRM, as well as additional topics that have arisen since issuance of the ANPRM, is summarized below. Details of the changes proposed in this rule are discussed below in section V. Section-by-Section Analysis.

• Topic A—Modifying the Definition of HCA. The ANPRM requested comments regarding expanding the definition of an HCA so that more miles of pipe would be subject to IM requirements and so that all Class 3 and 4 locations would be subject to the IM requirements. The Act, Section 5, requires that the Secretary of Transportation complete an evaluation and issue a report on whether integrity management requirements should be expanded beyond HCAs and whether such expansion would mitigate the need for class location requirements. PHMSA has prepared the class location report and a copy is available in the docket (*www.regulations.gov*) for this proposed rulemaking. PHMSA invites commenters to review the class location report when formulating their comments.

Although PHMSA is not proposing to expand the definition of an HCA, PHMSA is proposing to expand certain IM requirements beyond HCAs by creating a new ''moderate consequence areas (MCA).'' MCAs would be used to define the subset of non-HCA pipeline locations where periodic integrity assessments are required (§ 192.710), where material documentation verification is required (§ 192.607), and where MAOP verification is required (§§ 192.619(e) and 192.624). The proposed criteria for determining MCA locations would use the same process and the same definitions as currently used to identify HCAs, except that the threshold for buildings intended for human occupancy and the threshold for persons that occupy other defined sites, that are located within the potential impact radius, would both be lowered from 20 to 5. The intention is that any pipeline location at which persons are normally expected to be located would be afforded extra safety protections described above. In addition, as a result of the Sissonville, West Virginia incident, NTSB issued recommendation P–14–01, to revise the gas regulations to add principal arterial roadways including interstates, other freeways and expressways, and other principal arterial roadways as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures* to the list of ''identified sites'' that establish a high consequence area. PHMSA proposes to meet the intent of NTSB's recommendation by incorporating designated interstates, freeways, expressways, and other principal 4-lane arterial roadways (as opposed to NTSB's all ''other principal arterial roadways'') within the new definition of MCAs. PHMSA believes this approach would be cost-beneficial. The Sissonville, WV, incident location would not meet the current definition of an HCA, but would, however, meet the proposed definition of an MCA. PHMSA considered expanding the scope of HCAs instead of creating Moderate Consequence Areas. Such an approach was contemplated in the 2011 ANPRM and PHMSA received a number of comments on this approach. PHMSA concluded that this approach would be counter to a graded approach based on risk (*i.e.,* risk based gradation of requirements to apply progressively more protection for progressively greater consequence locations). By simply expanding HCAs, PHMSA would be simply lowering the threshold for what is considered ''high consequence.'' Expanding HCAs would require that all integrity management program elements (specified in subpart O) be applied to pipe located in a newly designated HCA. The proposed rule would only apply three IM program elements (assessment, periodic reassessment, and remediation of discovered defects) to the category of pipe that has lesser consequences than HCAs (*i.e.,* MCAs), but not to segments without any structure or site within the PIR (arguably ''low consequence areas''). There would be additional significant costs to apply all other integrity management program elements (most notably the risk analysis and preventive/mitigative measures program elements) to additional segments currently not designated as HCA. Also, if HCAs were expanded, long term reassessment costs would approximately triple (compared to the proposed MCA requirements) based on an almost 3:1 ratio of reassessment interval. For the above reasons, PHMSA is not proposing to expand HCAs. Instead, PHMSA is proposing to create and apply selected integrity management requirements to a category of lesser consequence areas defined as MCAs. With regard to the criteria for defining HCAs, PHMSA also considered several alternatives, including more relaxed population density and excluding small pipe diameters.

In addition, a major constituency of the pipeline industry (INGAA) has committed to apply IM principles to all segments where any persons are located. This is comparable to PHMSA's proposed MCA definition. PHMSA seeks comment on the relative merits of expanding High Consequence Areas

versus creating a new category of ''Moderate Consequence Areas.''

Another alternative PHMSA considered was a shorter a compliance deadline (10 years) and a shorter reassessment interval (15 years) for MCA assessments. The assessment timeframes in the proposed rule were selected based on a graded approach which would apply relaxed timeframes to MCAs, as compared to HCAs. The industry was originally required to perform baseline assessments for approximately 20,000 miles of HCA pipe within approximately 8 years from the effective date of the integrity management rule. PHMSA estimates that approximately 41,000 miles of pipe would require an assessment within 15 years under this proposed rule, thus constituting a comparable level of effort on the part of industry. The maximum HCA reassessment interval is 20 years for low stress pipe. The 20 year interval was selected to align with the longest interval allowed for any HCA pipe, which is 20 years for pipe operating less than 30% SMYS. A reassessment interval of 15 years for MCAs would be shorter than the reassessment interval for some HCAs. PHMSA also considered that compliance with the proposed rule would be performed in parallel with ongoing HCA reassessments at the same time, thus resulting in greater demand for ILI tools and industry resources than during the original IM baseline assessment period. In addition, the proposed rule incorporates other assessment goals, including integrity verification, maximum allowable operating pressure (MAOP) verification, and material documentation, thus constituting a larger/more costly assessment effort than originally required under IM rules. For the above reasons, PHMSA believes that this proposed rule would require full utilization or expansion of industry resources devoted to assessments. Therefore, PHMSA believes that compressing the timeframes would place unreasonably high demands on the industry's assessment capabilities. PHMSA also considered the possibility that placing burdensome demands on the industry's assessment capability might drive assessment costs higher. PHMSA seeks comments on the potential safety benefits, avoided lost gas, economic costs, and operational considerations involved in longer or shorter compliance periods for initial MCA assessment periods and re-assessment intervals.

More generally, PHMSA seeks comment on the approach and scope of the proposed rule with respect to applying integrity management program elements to additional pipe segments not currently designated as HCA, including, *inter alia,* alternative definitions of ''Moderate Consequence Area'' and limits on the categories of pipeline to be regulated within this new area.

• Topic B—Strengthening Requirements to Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs. The ANPRM requested comments regarding whether the requirements of Section 49 CFR 192.935 for pipelines in HCAs should be more prescriptive and whether these requirements, or other requirements for additional preventive and mitigative measures, should apply to pipelines outside of HCAs. Section 5 of the Act requires the Secretary of Transportation to evaluate and report to Congress on expanding IM requirements to non-HCA pipelines. PHMSA will further evaluate applying P&M measures to non-HCA areas after this evaluation is complete.

This NPRM proposes rulemaking for amending the integrity management rule to add requirements for selected preventive and mitigative measures (internal and external corrosion control).

Two special topics associated with preventive and mitigative measures, leak detection and automatic valve upgrades, were addressed by the NTSB and Congress. The NTSB recommended that all operators of natural gas transmission and distribution pipelines equip their supervisory control and data acquisition systems with tools to assist in recognizing and pinpointing the location of leaks, including line breaks; such tools could include a real-time leak detection system and appropriately spaced flow and pressure transmitters along covered transmission lines (recommendation P–11–10). In addition, Section 8 of the Act requires issuance of a report on leak detection systems used by operators of hazardous liquid pipelines which was completed and submitted to Congress in December 2012. Although that study is specific to hazardous liquid pipelines, its analysis and conclusions could influence PHMSA's approach to leak detection for gas pipelines. In response to the NTSB recommendations, PHMSA conducted as part of a larger study on pipeline leak detection technology a public workshop in 2012. This study, among other things, examined how enhancements to SCADA systems can improve recognition of pipeline leak locations. Additionally, in 2012 PHMSA held a pipeline research forum to identify technological gaps, potentially including the advancement of leak detection methodologies. PHMSA is developing a rulemaking with respect to leak detection in consideration of these studies and ongoing research. In addition, PHMSA is focusing this rulemaking on regulations oriented toward preventing incidents. Leak detection (in the context of mitigating pipe breaks as described in NTSB P–11–10) [34] and automatic valve upgrades are features that serve to mitigate the consequences of incidents after they occur but do not prevent them. In order to not delay the important requirements proposed in this NPRM, PHMSA will address the topic of incident mitigation later in a separate rulemaking. It is anticipated that advancing rulemaking to address the NTSB recommendations will follow assessment of the results of these actions.

PHMSA completed and submitted the valve study to congress in December 2012. PHMSA is developing a separate rulemaking related to the need for remotely or automatically controlled valves to addresses the NTSB recommendations and statutory requirements related to this topic as discussed under Topic H.

• Topic C—Modifying Repair Criteria. The ANPRM requested comments regarding amending the integrity management regulations by revising the repair criteria for pipelines in HCAs to provide greater assurance that injurious anomalies and defects are repaired before the defect can grow to a size that leads to a leak or rupture. PHMSA is proposing in this rule to revise the repair criteria for pipelines in HCAs. Revisions include repair criteria for cracks and crack-like defects, corrosion metal loss for defects less severe than an immediate condition (already included), and mechanical damage defects.

In addition, the ANPRM requested comments regarding establishing repair criteria for pipeline segments located in areas that are not in HCAs. PHMSA is proposing rulemaking for establishing repair criteria for pipelines that are not in HCAs. Such repair criteria would be similar to the repair criteria for HCAs, with more relaxed deadlines for non-immediate conditions. It is acknowledged that applying repair criteria to pipelines that are not in HCAs is one of the factors to be considered in the integrity management evaluation required in the Act, as discussed in Topic A above.

• Topic D—Improving Requirements for Collecting, Validating, and Integrating Pipeline Data. The ANPRM

[34] Leak detection in the context of detecting small, latent leaks such as leaks at fittings typical of gas distribution systems, and is outside the scope of the ANPRM, Topic B.

requested comments regarding whether more prescriptive requirements for collecting, validating, integrating, and reporting pipeline data are necessary. PHMSA also discussed this topic in a 2012 pipeline safety data workshop.

PHMSA issued Advisory Bulletin 12–06 to remind operators of gas pipeline facilities to verify their records relating to operating specifications for maximum allowable operating pressure (MAOP) required by 49 CFR 192.517. On January 10, 2011, PHMSA also issued Advisory Bulletin 11–01, which reminded operators that if they are relying on the review of design, construction, inspection, testing and other related data to establish MAOP, they must ensure that the records used are reliable, traceable, verifiable, and complete. PHMSA is proposing in this rule to add specificity to the data integration language in the IM rule to establish a number of pipeline attributes that must be included in these analyses, by explicitly requiring that operators integrate analyzed information, and by requiring that data be verified and validated. In addition, PHMSA has determined that additional rules are needed to ensure that records used to establish MAOP are reliable, traceable, verifiable, and complete. The proposed rule would add a new paragraph (e) to section 192.619 to codify this requirement and to require that such records be retained for the life of the pipeline.

- Topic E—Making Requirements Related to the Nature and Application of Risk Models More Detailed. The ANPRM requested comments regarding making requirements related to the nature and application of risk models more specific to improve the usefulness of these analyses in informing decisions to control risks from pipelines. This NPRM contains proposed requirements that address this topic.
- Topic F—Strengthening Requirements for Applying Knowledge Gained Through the IM Program. The ANPRM requested comments regarding strengthening requirements related to operators' use of insights gained from implementation of its IM program. In this NPRM, PHMSA proposes detailed requirements for strengthening integrity management requirements for applying knowledge gained through the IM Program. These requirements include provisions for analyzing interacting threats, potential failures, and worst-case incident scenarios from initial failure to incident termination. Though not proposed, PHMSA seeks comment on whether a time period for updating aerial photography and patrol information should be established.
- Topic G—Strengthening Requirements on the Selection and Use of Assessment Methods for pipelines requiring assessment. The ANPRM requested comments regarding the applicability, selection, and use of assessment methods, including the application of existing consensus standards. NTSB recommendation P–11–17 related to this topic, recommends that all gas pipelines be upgraded to accommodate ILI tools. PHMSA will consider separate rulemaking for upgrading pipelines pending further evaluation of the issue from new data being collected in the annual reports.

This NPRM proposes to strengthen requirements for the selection and use of assessment methods. The proposed rule would provide more detailed guidance for the selection of assessment methods, including the requirements in new § 192.493 when performing an assessment using an in-line inspection tool. This NPRM also proposes to add more specific requirements for use of internal inspection tools to require that an operator using this method must explicitly consider uncertainties in reported results when identifying anomalies. In addition, the proposed rulemaking would add a ''spike'' hydrostatic pressure test, which is particularly well suited to address SCC and other cracking or crack-like defects, guided wave ultrasonic testing (GWUT), which is particularly appropriate in cases where short segments, such as roads or railroad crossings, are difficult to assess, and excavation and *in situ* direct examination, which is well suited to address crossovers and other short, easily accessible segments that are impractical to assess by remote technology, as allowed assessment methods and would revise the requirements for direct assessment to allow its use only if a line is not capable of inspection by internal inspection tools.

The issue of selection and use of assessment methods is related to the statutory mandate in the Act for the Comptroller General of the United States to evaluate whether risk-based reassessment intervals are a more effective alternative. The Act requires an evaluation of reassessment intervals and the anomalies found in reassessments. While not directly addressing selection of assessment methods, the results of the evaluation will have an influence on the general approach for conducting future integrity assessments. PHMSA will consider the Comptroller General's evaluation when it becomes available. Additional rulemaking may be considered after PHMSA considers the results of the evaluation.

- Topic H—Valve Spacing and the Need for Remotely or Automatically Controlled Valves. The ANPRM requested comments regarding proposed changes to the requirements for sectionalizing block valves. In response to the NTSB recommendations, PHMSA held a public workshop in 2012 on pipeline valve issues, which included the need for additional valve installation on both natural gas and hazardous liquid transmission pipelines. PHMSA also included this topic in the 2012 Pipeline Research Forum. In addition, Section 4 of the Act requires issuance of regulations on the use of automatic or remote-controlled shut-off valves, or equivalent technology, where economically, technically, and operationally feasible on transmission pipeline facilities constructed or entirely replaced after the date of the final rule. The Act also requires completion of a study by the Comptroller General of the United States on the ability of transmission pipeline facility operators to respond to a hazardous liquid or gas release from a pipeline segment located in an HCA. Separate rulemaking on this topic will be considered based on the results of the study.
- Topic I—Corrosion Control. The ANPRM requested comments regarding proposed revisions to subpart I to improve the specificity of existing requirements. This NPRM proposes to revise subpart I, including a general update to the technical requirements in appendix D to part 192 for cathodic protection.
- Topic J—Pipe Manufactured Using Longitudinal Weld Seams. In recommendation P–11–15, the NTSB recommended that PHMSA amend its regulations to require that any longitudinal seam in an HCA be pressure tested in order to consider the seam to be ''stable.'' This issue is addressed in Topic N. PHMSA proposes to address this issue by revising the integrity management requirements in § 192.917(e)(3) to specify that longitudinal seams may not be treated as stable defects unless the segment has been pressure tested (and therefore would require an integrity assessment for seam threats). Also, PHMSA proposes to add new requirements for verification of maximum allowable operating pressure (MAOP) in new § 192.624.
- Topic K—Establishing Requirements Applicable to Underground Gas Storage. The ANPRM requested comments regarding establishing requirements within part 192 applicable to underground gas storage in order to help assure safety of

underground storage and to provide a firm basis for safety regulation. PHMSA will consider proposing a separate rulemaking that specifically focuses on improving the safety of underground natural gas storage facilities will allow PHMSA to fully consider the impacts of incidents that have occurred since the close of the initial comment period. It will also allow the Agency to consider voluntary consensus standards that were developed after the close of the comment period for this ANPRM, and to solicit feedback from additional stakeholders and members of the public to inform the development of potential regulations.

• Topic L—Management of Change. The ANPRM requested comments regarding adding requirements for management of change to provide a greater degree of control over this element of pipeline risk. This NPRM contains proposed requirements that address this topic. Specifically, PHMSA proposes to revise the general applicability requirements in § 192.13 to require each operator of an onshore gas transmission pipeline to develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary.

• Topic M—Quality Management Systems (QMS). The ANPRM requested comments regarding whether and how to impose requirements related to quality management systems. PHMSA will consider separate rulemaking for this topic.

• Topic N—Exemption of Facilities Installed Prior to the Regulations. The ANPRM requested comments regarding proposed changes to part 192 regulations that would repeal exemptions to pressure test requirements. The NTSB recommended that PHMSA repeal 49 CFR 192.619(c) and require that all gas transmission pipelines be pressure tested to establish MAOP (recommendation P–11–14). In addition, section 23 of the Act requires issuance of regulations requiring tests to confirm the material strength of previously untested natural gas transmission lines. In response to the NTSB recommendation and the Act, this NPRM proposes requirements for verification of maximum allowable operating pressure (MAOP) in accordance with new § 192.624 for certain onshore, steel, gas transmission pipelines, including establishing and documenting MAOP if the pipeline MAOP was established in accordance with § 192.619(c).

The Act also requires verification of records to ensure they accurately reflect the physical and operational characteristics of the pipelines and to confirm the established maximum allowable operating pressure of the pipelines. PHMSA issued Advisory Bulletin 12–06 on May 7, 2012 to notify operators of this required action. PHMSA has initiated an information collection effort to gather data needed to accurately characterize the quantity and location of pre-1970 gas transmission pipeline operating under an MAOP established by 49 CFR 192.619(c). This NPRM proposes requirements in new § 192.607 for certain onshore, steel, gas transmission pipelines to confirm and record the physical and operational characteristics of pipelines for which adequate records are not available.

• Topic O—Modifying the Regulation of Gas Gathering Lines. The ANPRM requested comments regarding modifying the regulations relative to gas gathering lines. The Act required several actions related to this topic, including: review existing regulations for gathering lines; provide a report to Congress; and make recommendations on: (1) The sufficiency of existing regulations, (2) the economic impacts, technical practicability, and challenges of applying existing federal regulations to gathering lines, and (3) subject to a risk-based assessment, the need to modify or revoke existing exemptions from Federal regulation for gas and hazardous liquid gathering lines. PHMSA proposes to address aspects of this topic identified before enactment of the Act in this NPRM. The report submitted to Congress will be evaluated to determine the need for any future rulemaking, specifically the need to apply integrity management concepts to gas gathering lines.

In addition, on August 20, 2014, the Government Accountability Office (GAO) released a report (GAO Report 14–667) to address the increased risk posed by new gathering pipeline construction in shale development areas. The GAO recommended that rulemaking be pursued for gathering pipeline safety that addresses the risks of larger-diameter, higher-pressure gathering pipelines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. PHMSA proposes to address this recommendation as described below in the ''Section-by-Section Analysis'' under § 192.9.

Additional Topics

• Inspection of Pipelines Following a Severe Weather Event. Existing pipeline regulations prescribe requirements for surveillance periodically patrolling of pipeline to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation, including unusual operating and maintenance conditions. The cause of the 2011 hazardous liquid pipeline accident resulting in a crude oil spill into the Yellowstone River near Laurel, Montana was scouring at the river crossing due to flooding. In this case, annual heavy flooding occurred in the Spring of the 2011. In late May, the operator shut down the pipeline for several hours to assess the state of the pipeline. Following the assessment, the operator restarted the pipeline and agreed to monitor the river area on a daily basis. On July 1, 2011 the pipeline ruptured which resulted in the release of 1,500 barrels of crude oil into the Yellowstone River. A second break, due to exposure to flood conditions, occurred several years later on the same pipeline led to an additional spill in the Yellowstone River. Other examples include Hurricane Katrina (2005) which resulted in significant damage to the oil and gas production structures and the San Jacinto flood (1994) which resulted in 8 ruptures and undermining of 29 other pipelines. In the context of the San Jacinto flood, ''undermining'' occurred when support material for the pipelines was removed due to erosion driven by the floodwaters. As a result, the unsupported pipelines were subjected to stress from the floodwaters that resulted in fatigue cracks in the pipe walls. Based on these examples of extreme weather events that did result, or could have resulted, in pipeline incidents, PHMSA has determined that additional regulations are needed to require, and establish standards for, inspection of the pipeline and right-of-way for ''other factors affecting safety and operation'' following an extreme weather event, such as a hurricane or flood, an earthquake, a natural disaster, or other similar event that has the likelihood of damage to infrastructure. The proposed rule would require such inspections, specify the timeframe in which such inspections should commence, and specify the appropriate remedial actions that must be taken to ensure safe pipeline operations. The new regulation would apply to onshore transmission pipelines and their rights-of-way.

• Notification for 7-Year Reassessment Interval Extension. Subsection 5(e) of the Act identifies a technical correction amending section 60109(c)(3)(B) of title 49 of the United States Code to allow the Secretary of Transportation to extend the 7- calendar year reassessment interval for an additional 6 months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. PHMSA would expect that any justification, at a minimum, would need to demonstrate that the extension does not pose a safety risk. PHMSA proposes to codify this statutory requirement.

• Reporting Exceedances of Maximum Allowable Operating Pressure. Section 23 of the Act requires operators to report to PHMSA each exceedance of the maximum allowable operating pressure (MAOP) that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. Implicit in § 192.605 is the intent for operators to establish operational and maintenance controls and procedures to effectively preclude operation at pressures that exceed MAOP. PHMSA expects that operators' procedures should already address this aspect of operations and maintenance, as it is a long-standing, critical aspect of safe pipeline operations. PHMSA issued ADB 12–11 to address exceedances of MAOP. However, PHMSA proposes to codify this statutory requirement in § 192.605.

• Consideration of Seismicity. Section 29 of the Act states that in identifying and evaluating all potential threats to each pipeline segment, an operator of a pipeline facility must consider the seismicity of the area. PHMSA proposes to codify this statutory requirement by adding requirements to explicitly reference seismicity for data gathering and integration, threat identification, and implementation of preventive and mitigative measures.

• Safety Regulations for In-line Inspection (ILI), Scraper, and Sphere Facilities. PHMSA is proposing to add explicit requirements for safety features on launchers and receivers associated with ILI, scraper and sphere facilities.

• Consensus Standards for Pipeline Assessments. The proposed rule would incorporate by reference industry standards for assessing the physical condition of in-service pipelines using in-line inspection, internal corrosion direct assessment, and stress corrosion cracking direct assessment. Periodic assessment of the condition of gas transmission pipelines in HCAs is required by 49 CFR 192.921 and 192.937. The regulations provide minimal requirements for the use of these assessment techniques since at the time these regulations were established, industry standards did not exist addressing how these techniques should be applied. Incorporation of standards subsequently published by the American Petroleum Institute (API), the National Association of Corrosion Engineers (NACE), and the American Society of Nondestructive Testing (ASNT) would assure better consistency, accuracy and quality in pipeline assessments conducted using these techniques.

F. Integrity Verification Process Workshop

An Integrity Verification Process (IVP) workshop was held on August 7, 2013. At the workshop, PHMSA, the National Association of State Pipeline Safety Representatives and various other stakeholders presented information and comments were sought on a proposed IVP that will help address mandates set forth in Section 23, Maximum Allowable Operating Pressure, of the Act and the NTSB Recommendations P–11–14 (repeal pressure test exemptions) and P–11–15 (stability of manufacturing and construction defects). Key aspects of the proposed IVP process include criteria for establishing which pipe segments would be subject to the IVP, technical requirements for verifying material properties where adequate records are not available, and technical requirements for re-establishing MAOP where adequate records are not available or the existing MAOP was established under § 192.619(c). Comments were received from the American Gas Association, the Interstate Natural Gas Association of America, and other stakeholders addressing the draft IVP flow chart, technical concerns for implementing the proposed IVP, and other issues. The detailed comments are available under Docket No. PHMSA–2013–0119. PHMSA considered and incorporated the stakeholder input, as appropriate, into this NPRM, which proposes requirements to address the current exemptions to pressure test requirements, manufacturing and construction defect stability, verification of MAOP where records to establish MAOP are not available or inadequate (new §§ 192.619(e) and 192.624), and verification and documentation of pipeline material for certain onshore, steel, gas transmission pipelines (new § 192.607).

III. Analysis of Comments on the ANPRM

In Section II of the ANPRM, PHMSA sought comments concerning the significance of the proposed issues to pipeline safety; whether new/revised regulations are needed and, if so, suggestions as to what changes are needed; and likely costs that would be associated with implementing any new/revised requirements. PHMSA posed specific questions to solicit stakeholder input. These included questions related to 15 specific topic areas in two broad categories:

1. Should IM requirements be revised and strengthened to bring more pipeline mileage under IM requirements and to better assure safety of pipeline segments in HCAs? Specific topics included:

A. Modifying the Definition of HCA,

B. Strengthening Requirements to Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs,

C. Modifying Repair Criteria,

D. Improving Requirements for Collecting, Validating, and Integrating Pipeline Data,

E. Making Requirements Related to the Nature and Application of Risk Models More Prescriptive,

F. Strengthening Requirements for Applying Knowledge Gained Through the IM Program,

G. Strengthening Requirements on the Selection and Use of Assessment Methods.

2. Should non-IM requirements be strengthened or expanded to address other issues associated with pipeline system integrity. Specific topics included:

H. Valve Spacing and the Need for Remotely or Automatically Controlled Valves,

I. Corrosion Control,

J. Pipe Manufactured Using Longitudinal Weld Seams,

K. Establishing Requirements Applicable to Underground Gas Storage,

L. Management of Change,

M. Quality Management Systems (QMS),

N. Exemption of Facilities Installed Prior to the Regulations,

O. Modifying the Regulation of Gas Gathering Lines.

PHMSA received a total of 1,463 comments; 1,080 from industry sources (Trade Associations/Unions, Pipeline Operators and Consultants); 316 comments from the public (Environmental Groups, Government Agencies/Municipalities, NAPSR and individual members of the general public); and 67 general comments not directly related to the ANPRM questions or categories. Commenters included:

- Citizen Groups
  - Environmental Defense Fund (EDF)
  - League of Women Voters of Pennsylvania (LWV)
  - Pipeline Safety Trust (PST)
  - State of Washington Citizens Advisory Committee on Pipeline Safety (CCOPS)
- Consultants
  - Accufacts Inc.
  - Oleksa and Associates, Inc.
  - Thomas M. Lael
  - WKM Consultancy, LLC
- Government Agencies
  - California Public Utilities Commission (CPUC)
  - City and County of San Francisco (CCSF)
  - Federal Energy Regulatory Commission (FERC)
  - Harris County Fire Marshal's Office (HCFM)
  - Interstate Oil and Gas Compact Commission (IOGCC)
  - Iowa Utilities Board
  - Kansas Corporation Commission (KCC)
  - Kansas Department of Health and Environment (KDHE)
  - National Association of Pipeline Safety Representatives (NAPSR)
  - National Transportation Safety Board (NTSB)
  - Railroad Commission of Texas (TRRC)
  - State of Alaska—AK Natural Gas Development Authority (AKN)
  - State of Alaska Dept. of Natural Resources (AKDNR)
  - Wyoming County Commissioners of Pennsylvania (WYCTY)
- Pipeline Industry
  - Air Products and Chemicals, Inc.
  - Alliance Pipeline
  - Ameren Illinois (AmerenIL)
  - Atmos Energy
  - Avista Corporation
  - CenterPoint Energy
  - CenterPoint Energy Resources Corp.
  - Chevron
  - Dominion East Ohio Gas (DEOG)
  - El Paso (EPPG)
  - ITT Exelis Geospatial Systems
  - Kern River Gas Transmission Company
  - MidAmerican Energy Company
  - National Fuel Gas Supply Corporation
  - National Grid
  - Nicor Gas
  - NiSource Gas Transmission & Storage
  - Northern Natural Gas
  - Paiute Pipeline Company
  - Panhandle Energy
  - Questar Gas Company
  - Questar Pipeline Company
  - SCGC and SDG&E (Sempra)
  - Southern Star Central Gas Pipeline, Inc.
  - Southwest Gas Corporation
  - Spectra Energy
  - TransCanada
  - TransCanada Corporation
  - Waste Management, Inc
  - Williams Gas Pipeline
- Municipalities
  - Delaware Solid Waste Authority (DSWA)
  - Iowa Association of Municipal Utilities (IAMU)
- Trade Associations
  - American Gas Association (AGA)
  - American Public Gas Association (APGA)
  - Gas Processors Association (GPA)
  - Gas Piping Technology Committee (GPTC)
  - Independent Petroleum Association of America, its Cooperating Associations, and the American Petroleum Institute (IPAA/API)
  - Interstate Natural Gas Association of America (INGAA)
  - NACE International
  - National Solid Waste Management Association (NSWMA)
  - National Utility Locating Contractors Association (Locators)
  - Oklahoma Independent Petroleum Association (OKIPA)
  - Texas Oil and Gas Association (TXOGA)
  - Texas Pipeline Association (TPA)
- Trade Unions
  - Professional Engineers in California Government (PECG)
- 31 Private Citizens

Commenters responded to ANPRM questions, but also submitted comments on subjects generally related to gas pipeline safety regulation (but not related to an ANPRM topic) and general comments related to a topic but not in response to any specific question. This NPRM presents a summary of the comments received (similar or duplicate comments are consolidated). The general (no-topic) comments are presented first under the heading ''General Comments.'' Comments on each topic follow under the heading ''Comments on ANPRM Section II Topics on Which PHMSA Sought Comment,'' beginning with general comments related to the topic and then proceeding to each individual question.

General Comments

General Industry Comments

1. A number of commenters associated with the pipeline industry suggested that PHMSA should defer action on the changes discussed in the ANPRM until the studies required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 are completed. They contended the Act presents critical issues that require priority attention. They believe the questions raised by Congress, and to which the studies are addressed, could lead to fundamental changes in how pipeline safety is regulated and these changes need to be understood before new rules are written. Several commenters also suggested PHMSA lacks the resources to pursue simultaneously the required studies and complicated rulemakings. The Railroad Commission of Texas also suggested no new requirements be proposed until the effects of the new Act are understood, since they believe that the Act will change the scope of regulatory authority and impose additional costs on industry and regulators.

Response

PHMSA has placed studies and evaluations that relate to the topics in this proposed rulemaking on the docket. PHMSA seeks public comment on those reports and will consider comments before finalizing this rule. Other topics not addressed in this rulemaking that require additional study or evaluation will be addressed separately. Areas for safety improvement that have previously been identified and that are not dependent on the outcome of the required studies are also the subject of the proposals in this Notice.

2. INGAA, AGA, and several pipeline operators and consultants commented that the ANPRM suggested that PHMSA intends to pursue prescriptive regulation in a number of areas. They objected to this approach. They prefer performance-based regulation, under which operators have greater flexibility in deciding how the required safety goal can be met, considering the specific circumstances of their pipeline systems. They noted that integrity management, a performance-based approach, has greatly improved pipeline safety, and suggested PHMSA consider expanding the elements to be covered in an IM plan and providing more well-defined guidelines on how these expanded plans should evolve over time. They noted that implementing pipeline safety regulations is a complex process and implementing prescriptive requirements is usually inefficient. They also noted that prescriptive requirements tend to discourage technological advancements which can lead to improved means to assure safety.

Response

PHMSA believes performance-based regulations are central to improving pipeline performance. In some instances, however, prescriptive

requirements may be necessary to provide the requisite improvement to pipeline safety performance; for example, requirements for corrosion control, repair conditions, and repair criteria to more specifically address significant corrosion issues. In these cases, the unsafe condition can be clearly specified, and steps necessary to remediate the risk are well-understood engineering practice. PHMSA is committed to an efficient and effective approach to pipeline safety, and using prescriptive regulatory requirements only where necessary.

3. AGA, Texas Pipeline Association, Texas Oil and Gas Association, and a number of pipeline operators objected to the scope and pace of change in pipeline safety regulation. These commenters noted that the ANPRM covered a number of complex issues. In addition, they noted that pipeline operators are still implementing a number of large new initiatives including control room management, public awareness, distribution integrity management, and damage prevention. They commented that the industry needs time to complete implementing these other new regulations and PHMSA and the industry need time to evaluate the effect they have on pipeline safety. AGA specifically expressed concern that the pace of change could result in unintended adverse consequences. The Texas Associations suggested that any expansion of non-HCA regulations should address highest risks first and be structured to tailor requirements to different pipeline conditions because other approaches are likely to result in increased costs with little safety benefit. MidAmerican commented that the ANPRM appeared to be based on an incorrect assumption that there are no current requirements applicable to non-HCA pipe; they noted that part 192 includes many requirements applicable to non-HCA segments and that they assure safety. Atmos suggested PHMSA avoid the ''one size fits all'' approach to pipeline safety regulations.

Response

PHMSA understands that assimilation of change is an important consideration and agrees that the ANPRM covers a number of complex issues. Many of the more complex issues contemplated in the ANPRM, such as leak detection and automatic valves, will be addressed by separate rulemaking so that more careful and detailed analysis can be completed. However, PHMSA is proposing rulemaking in a number of areas to assure that the regulations continue to provide an adequate level of safety for both HCAs and non-HCAs. Additional discussion of the basis for the proposed rulemaking is presented in the response to comments received for each ANPRM topic and in Section V below (Section-by-Section Analysis).

4. A number of industry commenters suggested that PHMSA exercise care in developing broad requirements that may be inappropriate for some types of pipelines. In particular, APGA noted that ''transmission'' pipeline operated by local distribution companies is very different from long-distance transmission lines. They are typically smaller diameter, operate at lower pressures, and are often made of plastic. AGA and distribution pipeline operators noted that leaks are a routine management issue for distribution pipelines and those requirements appropriate to leak response for transmission pipelines would not be appropriate in a distribution context. The Texas Oil & Gas Association requested that any changes be examined for possible unexpected impact on gathering lines, which also differ from transmission pipelines.

Response

PHMSA is aware of the varying nature of pipeline systems. One aspect of performance-based requirements is the ability of operators to customize the integrity management program so that it is appropriate to its circumstances.

5. AGA and some pipeline operators noted that the ANPRM suggested that PHMSA intends to extrapolate hazardous liquid pipeline experience to gas pipelines. In particular, they expressed concern regarding the discussion of leak detection. They noted pin-point leak detection may be practical for non-compressible liquids but is not for gas.

Response

PHMSA appreciates the significant differences between hazardous liquid pipelines and gas pipelines with respect to leak detection. PHMSA is sponsoring studies and research to address leak detection in a responsible way, while still being responsive to related NTSB recommendations. PHMSA is considering separate rulemaking for leak detection that will address these studies and research.

6. Pipeline industry trade associations reported that their members plan to implement voluntary approaches to improve pipeline safety. INGAA reported it has implemented a strategy to achieve a goal of zero pipeline incidents. This strategy includes voluntary application of IM principles to non-HCA pipeline segments where people live. Their goal is to apply ASME/ANSI B31.8S, Managing System Integrity of Gas Pipelines, principles to 90 percent of people who live or work in close proximity to pipelines by 2020, and 100 percent by 2030. INGAA's strategy also includes assuring the fitness for service of pipelines installed before federal safety regulations were promulgated, improving incident response time (to less than one hour in populated areas), and implementing the Pipelines and Informed Planning Alliance (PIPA) guidelines. AGA similarly reported their intentions to address improvements to safety proactively by applying Operator Qualification to new construction, continuing to advance IM principles (including developing industry guidelines for data management and data quality), and working with a coalition of PIPA stakeholders to adopt PIPA-recommended best practices, among other initiatives.

Response

PHMSA commends the pipeline industry for these initiatives and is committed to working with the industry to improve performance toward the goal of zero pipeline incidents.

7. A number of comments addressed the cost-benefit analyses that will be required in support of rulemaking that results from this ANPRM. AGA noted that a detailed estimate has not been completed but that preliminary evaluations suggest that the cost of implementing the initiatives included in the ANPRM could well exceed the cost of implementing the 2003 gas transmission IM rule. APGA agreed that some of the concepts discussed in the ANPRM are potentially very costly and must be considered carefully. Accufacts cautioned PHMSA to be wary of efforts to distort the cost-benefit analyses by hyper inflating costs. As an example, Accufacts pointed to estimates of costs to perform hydrostatic tests ranging from $500,000 to $1,000,000 per mile compared to costs of $29,400 to $40,000 per mile cited in the NTSB report on the San Bruno accident.

Response

PHMSA acknowledges that estimates of hydrostatic test costs can vary and that there is risk in using overstated estimates in the analysis of benefits and costs since regulatory decisions regarding public safety can be based on these results. For the Preliminary Regulatory Impact Assessment (PRIA) for this proposed rule PHMSA used vendor pricing data to develop unit costs for pressure testing. These costs represent the contractor's costs to complete an eight hour pressure test for

various segment diameters and lengths. PHMSA applied a multiplier to account for other operator costs, such as manifold installation and operational oversight, and also added estimated costs to provide temporary gas supplies and the market value of lost gas. Based on these data and assumptions, PHMSA estimated per mile pressure test costs range from approximately $60,000 per mile (12″ diameter, 10 mile segment) to 630,000 (36″ diameter, one mile segment). Detailed explanations of these unit costs are available in the PRIA, provided in the regulatory docket.

8. AGA and several pipeline operators suggested PHMSA should establish jointly with industry a committee to evaluate pipeline data and to determine whether more data is needed. They commented industry has repeatedly made this request and PHMSA has, to date, not responded. They contended PHMSA's current analysis of pipeline safety performance data is inadequate. Similarly, Panhandle Energy noted a number of the questions in the ANPRM requested data on various subjects; Panhandle expressed its belief that PHMSA collects and has access to at least some of data requested, and this data, collected pursuant to regulatory requirements, should be more complete, and consistently collected and reported, than piecemeal collections of data in response to this ANPRM. Expressing a somewhat contrary view, El Paso suggested more data should be collected and analyzed before notices of proposed rulemakings are prepared; PHMSA needs to collect and analyze data to determine the proper path for future requirements, if any.

Response

In response to NTSB recommendation P–11–19, PHMSA held a pipeline safety data workshop in January 2013. The workshop: (1) Summarized the data OPS collects, who it is collected from, and why it is collected; (2) addressed how stakeholders, including OPS, industry, and the public use the data; (3) addressed data quality improvement efforts and performance measures; and (4) discussed the best method(s) for collecting, analyzing, and ensuring transparency of additional data needed to improve performance measures. PHMSA considered the results of the workshop as well as the comments to the ANPRM related to pipeline safety performance data.

9. APGA suggested PHMSA revise the definitions of transmission and distribution pipelines to be more risk-based. APGA contended that the current definitions are not risk-based and lead to inappropriate outcomes. In particular, classification of some pipelines as ''transmission'' based on functional aspects of the current definition leads to inappropriate application of requirements. In a similar vein, Oleksa and Associates suggested it may be time to reduce IM requirements on low-stress transmission pipelines, which pose lower risk than high-stress lines. Texas Pipeline Association and Texas Oil & Gas Association commented PHMSA should not extrapolate experience with interstate pipelines to intrastate lines, which differ in design and operation.

Response

The definition of transmission vs. distribution pipelines and the applicability requirements for integrity management in High Consequence Areas is not within the scope of this proposed rule. The general topic of the scope and applicability of integrity management is addressed in the class location report which available in the docket.

10. Northern Natural Gas recommended all exemptions from one-call requirements be eliminated. They noted excavation damage remains, by far, the single greatest threat to pipeline safety and management of excavation damage, through one-call programs, has been demonstrated to be an effective means of countering that threat.

Response

This comment is not within the scope of the ANPRM topics. However, PHMSA has revised the pipeline safety regulations related to pipeline damage prevention programs, which includes one-call programs, in an final rule issued July 23, 2015 (80 FR 43836).

11. The Gas Processors Association, Texas Pipeline Association, and Texas Oil & Gas Association commented regarding current efforts to clarify the applicability of part 192 requirements, particularly requirements for distribution integrity management, to farm taps. They suggested PHMSA is engaged in an expansion of requirements in this area without notice or a demonstrated safety need. They suggested PHMSA initiate a rulemaking specifically to clarify requirements applicable to farm taps.

Response

Treatment of farm taps is not within the scope of the ANPRM topics. However, PHMSA has engaged in dialogue with industry on this topic and will continue to consider options to address this issue in a separate action.

12. Northern Natural Gas suggested PHMSA reduce the time allowed for conducting a baseline assessment in cases where a new HCA is found, tailored to the circumstances of the particular segment. Northern expressed its belief this would address threats to integrity in areas affecting population more quickly than current requirements.

Response

Currently, § 192.905(c) requires that newly identified HCAs be incorporated into the baseline assessment plan within one year. PHMSA does not currently have plans to address this requirement. However, periodically DOT or PHMSA seeks public input on retrospective review of existing regulations under Executive Order 13563. PHMSA encourages the commenter to raise this issue the next time DOT or PHMSA solicits comments on retrospective review of existing regulations.

13. Alliance Pipeline suggested many pipeline safety questions can be answered by applying INGAA's five guiding principles of pipeline safety. They noted INGAA has developed the Integrity Management-Continuous Improvement (IMCI) Initiative to implement these principles and suggested PHMSA actively engage with INGAA in developing workable solutions to pipeline safety issues.

Response

PHMSA appreciates the industry efforts to improve pipeline safety and is committed to working with all stakeholders toward this end.

14. Paiute Pipeline and Southwest Gas commented integrity management requirements have not been in effect long enough to gauge their effectiveness and decide whether additional changes are needed. The companies noted the first, baseline assessments of pipeline segments subject to those requirements are only now being completed. AGA and other pipeline operators agreed, noting IM is still new, operators are still refining their processes, and PHMSA should approach change with caution.

Response

While the first round of baseline assessments are only now being completed, the gas IM rule has been in place approximately 10 years. PHMSA expects that operator IM programs should have significantly matured in this timeframe.

15. Panhandle Energy suggested that PHMSA evaluate rule changes that could have prevented incidents which occurred in recent years. Any initiatives that would not have contributed to improved safety, they suggest, should be postponed or treated as lower priority activities. Panhandle suggested rulemaking without a sound basis is not

only ineffective but counterproductive in that it diverts resources that could have been used to improve safety. Questar Gas similarly commented PHMSA needs to minimize unnecessary activities that inappropriately divert safety resources. Questar also recommended that PHMSA explicitly consider the diversity within the regulated community.

Response

One of the major motivations for PHMSA's issuance of the ANPRM was to solicit information useful to ensuring that pipeline safety reforms have a sound basis. PHMSA is also required by Executive Orders 12866 and 13563 to ensure that the benefits of its rules justify the costs, to the extent permitted by law. PHMSA has prepared an initial regulatory impact analysis for this proposed rule, which is available in the docket for this rule. PHMSA encourages the commenter as well as other members of the public to review the analysis and provide input for improving the final rule.

16. AGA and several pipeline operators commented that, while enhancements can be made, IM requirements need not be subjected to wholesale change. They cited GAO and NTSB reports on the efficacy of transmission pipeline integrity management and the lack of pipeline safety issues among the NTSB's ''Most Wanted'' issues.

Response

While PHMSA believes that IM has led to improvements in managing pipeline integrity, recent incidents and accidents demonstrate that much work remains to improve pipeline safety.

17. AGA and pipeline operators noted that transmission and distribution integrity management are not distinct activities for most intrastate pipeline operators. They contended that the ANPRM seemed to be based on a presumption that operators manage their transmission and distribution pipeline safety differently, and that this assumption is without basis.

Response

PHMSA has promulgated specific IM rules for both transmission and distribution systems with a view toward allowing operators to customize their performance based programs as appropriate to their specific systems.

18. AGA and several pipeline operators suggested that any changes to public awareness requirements should be made at the state level. They noted that federal requirements in this area are new and that effectiveness reviews are still in progress.

Response

This issue is not within the scope of the ANPRM. However, PHMSA has revised the pipeline safety regulations related to pipeline damage prevention programs in a final rule issued July 23, 2015 (80 FR 43836).

19. NACE International suggested that adopting its standards for corrosion control would be the best means to accomplish the goal of maintaining pipelines safe and functional for long periods of time.

Response

This NPRM proposes to incorporate industry consensus standards into the regulations for assessing the physical condition of in-service pipelines using in-line inspection, internal corrosion direct assessment, and stress corrosion cracking direct assessment. In addition, this NPRM proposes to enhance subpart I requirements for corrosion control and to revise Appendix D to improve requirements for cathodic protection.

20. The NTSB commented that regulations for gas transmission pipelines can and should be improved and expressed its support for the overall intent of the ANPRM. The NTSB noted publication of the ANPRM prior to its recommendations resulting from the San Bruno incident investigation precluded any mention in the ANPRM of these NTSB safety recommendations. The NTSB suggested PHMSA should seek comment on its recommendations.

Response

PHMSA has reviewed the NTSB recommendations that were issued on September 26, 2011 and found that several recommendations related directly to the topics addressed in the ANPRM and that may impact the proposed approach to rulemaking. The topics impacted are discussed above in the Background section above, in sections II.C and II.E, and include NTSB Recommendations P–11–10, P–11–11, P–11–14, P–11–15, P–11–17, and P–11–19. The NTSB's other recommendations will be addressed in separate proceedings.

21. El Paso suggested that the proper approach to attain the highest pipeline safety levels is through a structured, deliberate rulemaking that closely examines all issue aspects prior to making informed decisions.

Response

PHMSA agrees and is taking a careful, structured, and phased approach to enhancing pipeline safety regulations and IM performance standards.

22. Thomas M. Lael, a pipeline industry consultant, suggested any new regulations be concise and clear. He contended past lack of clarity has created the need for many re-interpretations and enforcement problems.

Response

PHMSA concurs but also notes that performance-based regulations, by their nature, are not as specific, nor as easily measurable, as prescriptive regulations, but are more likely to improve safety and the cost-effectiveness of regulations. PHMSA provides guidance to help stakeholders understand the intent and scope of performance-based regulations.

General Public Comments

1. A member of the public stated that the ANPRM did not provide specific options for consideration. As written, only those with direct involvement in the industry could understand it well enough to comment. Presenting the options more specifically would allow for better informed public comment. The discussion should also include a regional component, since issues affecting different states/regions are not the same.

Response

By its nature, the ANPRM did not propose specific alternatives or rules, but solicited input to help inform future proposals. This NPRM provides specific proposed rules for public comment.

2. The Alaska Natural Gas Development Authority stated that the regulations should require consideration of earthquakes, as recent history shows they can be very important to safety of high-pressure gas lines.

Response

Section 29 of the Act states that in identifying and evaluating all potential threats to each pipeline segment, an operator of a pipeline facility shall consider the seismicity of the area. Rulemaking for this issue is addressed in this NPRM and would add requirements to explicitly reference seismicity for data gathering and integration, threat identification and implementation of preventive and mitigative measures.

3. The Environmental Defense Fund pointed out that methane is a very potent greenhouse gas. They commented that PHMSA should consider and minimize the potential environmental effects of any future rulemaking. They suggested EPA's Natural Gas Star program as a model.

Response

The proposals in this rulemaking are designed to minimize the risk of pipeline failures, which will result in environmental benefits. The draft environmental assessment addresses the environmental effects of this rulemaking.

In addition, the RIA provides estimates of the environmental benefits of this proposed rule. Natural gas transported in transmission pipelines contains heat-trapping gases that contribute to global climate change and its attendant societal costs. Of these gases, of primary importance for evaluation are methane—by far, the largest constituent of natural gas—and carbon dioxide. Other natural gas components (ethane, propane, etc.) contribute as well, but they account for a much smaller percentage of the natural gas mixture and, as a result, are much less significant than methane in terms of their environmental impact. The proposed rule is expected to prevent incidents, leaks, and other types of failures that might occur, thereby preventing future releases of greenhouse gases (GHG) to the atmosphere, thus avoiding additional contributions to global climate change. PHMSA estimated net GHG emissions abatement over 15 years of 69,000 to 122,000 metric tons of methane and 14,000 to 22,000 metric tons of carbon dioxide, based on the estimated number of incidents averted and emissions from pressure tests and ILI upgrades.

4. A member of the public questioned the openness and clarity of PHMSA's enforcement of pipeline safety regulations, and the use of civil penalty revenues.

Response

This comment is not within the scope of the ANPRM topics, however, it should be noted that PHMSA embraces transparency in its regulatory oversight program and has established a Pipeline Safety Stakeholder Communications Web site, *http://primis.phmsa.dot.gov/comm/*, which presents a variety of reports detailing enforcement activity. These reports are offered on both nationwide and operator-specific bases.

5. One member of the public suggested that DOT define ''safe corridors'' for above-ground construction of pipelines. The commenter suggested this would be similar, in principle, to the interstate highway system. It would help to keep pipelines separated from residences, avoid corrosive environments, and make pipelines available for routine direct examination. At a minimum, this commenter suggested the regulations should specify a minimum separation between new pipelines and residences, as does the New Jersey state code, or homebuyers be informed when a home is within the potential impact radius of a gas transmission pipeline so they may make an informed buying decision.

Response

This comment addresses pipeline siting and routing, which is outside the scope of PHMSA's statutory authority. As specified in 49 U.S.C. 60104, Requirements and Limitations of the Act, PHMSA is prohibited from regulating activities associated with locating and routing pipelines. Paragraph (e) of the statute states ''Location and routing of facilities.—This chapter does not authorize the Secretary of Transportation to prescribe the location or routing of a pipeline facility.'' However, PHMSA is an active participant in the Pipeline and Informed Planning Alliance (PIPA) and encourages all stakeholders to learn about, and become involved with, PIPA. More information can be obtained online at: *http://primis.phmsa.dot.gov/comm/pipa/landuseplanning.htm*.

6. One member of the public noted there is an increasing trend in significant incidents and suggested that this trend may be related to undue influence of the pipeline industry on the regulations under which it operates. The commenter recommended regulations should not be weakened in favor of industry. The League of Women Voters of Pennsylvania also recommended that regulatory agencies be insulated from political and other influences of natural gas pipeline companies to avoid the appearance of a conflict of interest.

Response

PHMSA appreciates these comments. PHMSA is committed to improving pipeline safety, and that is the goal of this endeavor. Significant incidents on Gas Transmission (GT) pipelines have averaged between 70 and 80 incidents per year over the past 9 years. The existing integrity management regulations in 49 CFR part 192, subpart O, addresses pipeline integrity in HCAs, which is only about 7 percent of the GT pipeline mileage. This proposed NPRM is focused on strengthening requirements in HCAs and applying integrity management principles to areas outside HCAs to better address safety issues. In addition, the proposed rule seeks to address significant issues that caused or contributed to the San Bruno accident, which include lack of pressure test, inadequate records, poor materials, and inadequate integrity assessment. The operator reports submitted to PHMSA as mandated by the Act confirm that these issues are widespread for both HCA and non-HCA pipe segments.

7. The Harris County Fire Marshall's Office (HCFM) suggested stiffer regulations are needed for gas transmission pipeline safety, because of the large potential for negative impact and catastrophic consequences. HCFM expressed concern about corrosion control and current inspection practices for aging transmission infrastructure.

Response

This NPRM proposes enhanced corrosion control requirements, including periodic close interval surveys, post construction surveys for coating damage, and interference current surveys. This NPRM also proposes enhanced requirements for internal corrosion and external corrosion management programs.

8. The Pipeline Safety Trust (PST) commented that the ANPRM, itself, may heighten and fuel existing public concerns about pipeline safety. PST noted that many of the questions asked the industry to provide information they believe the public would believe PHMSA should already have. PST expressed its view that the number and types of questions asked in the ANPRM reflect gaps in PHMSA's knowledge of gas transmission pipeline systems and operator practices.

Response

PHMSA appreciates these comments. PHMSA is committed to improving pipeline safety and stakeholder input is valuable to the regulatory process.

9. Professional Engineers in California Government (PECG) commented that private companies should not be solely responsible for the safety of their pipelines. PECG contended that this approach has not worked. PECG also suggested PHMSA examine options for increasing the number of inspectors at state pipeline regulatory agencies and require public inspectors be on site for pipeline construction and testing. They contended such inspection is necessary to assure that older pipelines are tested adequately and replaced when needed.

Response

PHMSA appreciates these comments. PHMSA is committed to ensuring that operators maintain and operate their pipelines safely. This rulemaking contains a number of measures aimed at enhancing oversight.

10. The City and County of San Francisco (CCSF) noted the scope of potential rulemaking discussed in the

ANPRM did not include consideration of PHMSA's coordination with and oversight of state certified agencies. In order to ensure the proper oversight over natural gas transmission operators and the safe operation of natural gas transmission lines, CCSF believes PHMSA must address its state certification program and its oversight of state enforcement of pipeline safety standards. CCSF recommended PHMSA publish regulations for certification of state programs. They cited NTSB recommendation P–11–20 and asserted PHMSA has not corrected inadequate practices of the California Public Utilities Commission.

Response

This comment is outside the scope of this rulemaking. PHMSA is addressing NTSB recommendation P–11–20 separately.

11. Two members of the public suggested the processes of the Federal Energy Regulatory Commission (FERC) for siting pipelines should be revised. One suggested a Commission on Public Accountability and Safety Standards be established, consisting of a majority of local public officials, first responder experts, and independent qualified engineers, to make recommendations for FERC's pre-application process and standards. The purpose would be to assure standards require public accountability for review and vetting of pipeline safety issues with local authorities when pipelines are proposed. The other commenter suggested the relationship between FERC and DOT should be clarified, that a company's enforcement history be taken into account in siting decisions, and PHMSA be a full party to all FERC proceedings. The commenter believes this is necessary because FERC does not have a public safety mandate.

Response

PHMSA is a separate agency from FERC and has no statutory authority with respect to pipeline siting or approval. As specified in 49 U.S.C. 60104, Requirements and Limitations of the Act, PHMSA is prohibited from regulating activities associated with locating and routing pipelines. Paragraph (e) of the statute states ''Location and routing of facilities.—This chapter does not authorize the Secretary of Transportation to prescribe the location or routing of a pipeline facility.'' However, PHMSA is an active participant in the Pipeline and Informed Planning Alliance (PIPA) and encourages all stakeholders to learn about, and become involved with, PIPA. More information can be obtained online at: *http://primis.phmsa.dot.gov/comm/pipa/landuseplanning.htm*.

12. Two members of the public commented federal regulations should not override local ordinances. They noted the concern of local authorities is safety, while others are concerned about industry costs. They believe federal regulations that allow operators significant discretion are a poor basis to supersede specific local requirements.

Response

PHMSA appreciates these comments. Federal regulations provide for a uniform body of standards and requirements related to pipeline safety. PHMSA is receptive to input from state and local authorities on pipeline safety issues. States and local authorities may adopt requirements that are more stringent than and consistent with the federal regulations for their intrastate pipelines if they have a 49 U.S.C. 60105 certification.

13. One member of the public suggested regulations require periodic safety audits by an auditor not selected by the pipeline operator. The commenter further suggested that local authorities should have approval authority in the choice of the auditor. The commenter contended this approach would strengthen public confidence in pipeline safety.

Response

PHMSA appreciates this comment. Highly trained federal and state pipeline inspectors conduct inspections of pipeline operators, their facilities, and their compliance programs on a regular basis.

Comments on ANPRM Section II Topics on Which PHMSA Sought Comment

In section II of the ANPRM, commenters were urged to consider whether additional safety measures are necessary to increase the level of safety for those pipelines that are in non-HCA areas as well as whether the current IM requirements need to be clarified and in some cases enhanced to assure that they continue to provide an adequate level of safety in HCAs. PHMSA posed specific questions to solicit stakeholder input. These included questions related to the following topics:

A. Modifying the Definition of HCA,

B. Strengthening Requirements to Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs,

C. Modifying Repair Criteria,

D. Improving Requirements for Collecting, Validating, and Integrating Pipeline Data,

E. Making requirements Related to the Nature and Application of Risk Models More Prescriptive,

F. Strengthening Requirements for Applying Knowledge Gained Through the IM Program

G. Strengthening Requirements on the Selection and Use of Assessment Methods,

H. Valve Spacing and the Need for Remotely or Automatically Controlled Valves,

I. Corrosion Control,

J. Pipe Manufactured Using Longitudinal Weld Seams,

K. Establishing Requirements Applicable to Underground Gas Storage,

L. Management of Change,

M. Quality Management Systems (QMS),

N. Exemption of Facilities Installed Prior to the Regulations,

O. Modifying the Regulation of Gas Gathering Lines.

Each topic is summarized as presented in the ANPRM, then general comments related to the topic are presented, followed by each individual question and comments received for the question.

A. Modifying the Definition of HCA

The ANPRM stated that ''IM requirements in subpart O of part 192 specify how pipeline operators must identify, prioritize, assess, evaluate, repair and validate; *[sic]* through comprehensive analyses, the integrity of gas transmission pipelines in HCAs. Although operators may voluntarily apply IM practices to pipeline segments that are not in HCAs, the regulations do not require operators to do so. A gas transmission pipeline ruptured in San Bruno, California on September 9, 2010, resulting in eight deaths and considerable property damage. As a result of this event, public concern has been raised regarding whether safety requirements applicable to pipe in populated areas can be improved. PHMSA is thus considering expanding the definition of an HCA so that more miles of pipe are subject to IM requirements.'' The ANPRM then listed questions for consideration and comment. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic A

1. INGAA and a number of pipeline operators noted this is an opportune time for considering the next steps in integrity management, since baseline assessments under the current IM rules are now being completed. INGAA noted its policy goal is to apply IM principles

(as described in ASME/ANSI B31.8S) beyond HCAs, covering 90 percent of people living near transmission pipelines by 2020 and 100 percent by 2030. TransCanada submitted information in support of INGAA's proposal, noting that by the end of 2012 the company will have assessed more than 85 percent of its US pipeline mileage covering more than 95 percent of people living near their pipelines. Thus, the current IM rules are having a significant positive impact on pipeline safety. TransCanada believes significant technological challenges would be encountered if IM regulations were extended to all pipelines.

2. MidAmerican commented it would be reasonable to differentiate between transmission pipelines operating above and below 30 percent specified minimum yield strength (SMYS) in terms of IM requirements. They estimated that less than 3 percent of local distribution company (LDC) transmission lines operate at greater than 30 percent SMYS.

3. MidAmerican and a member of the public suggested PHMSA eliminate class locations in favor of better-defined HCAs. They contend such a change would result in administrative savings for pipeline operators.

4. Southwest Gas and Paiute commented no new regulations should be promulgated in this area until the study required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 is completed.

Response to General Comments for Topic A

PHMSA appreciates the information provided by the commenters. Section 5 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act) (Pub. L. 112–90) requires the Secretary of Transportation to ''evaluate (1) whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas; and (2) 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.'' PHMSA has completed the report mandated by the Act that documents that evaluation and addresses whether integrity management (IM) program requirements should be expanded beyond high consequence areas (HCAs) and, specifically for gas transmission pipelines regulated under 49 Code of Federal Regulations (CFR) part 192, whether such expansion would mitigate the need for class location designations and corresponding requirements. The class location report is available for review in the docket.

In October 2010 and August 2011, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published notices in the **Federal Register** to solicit comments on revising the pipeline safety regulations applicable to hazardous liquid and natural gas transmission pipelines including expansion of IM program requirements beyond HCAs. In general, industry representatives and pipeline operators were opposed to any expansion of HCAs and in favor of eliminating class locations on newly constructed pipelines, whereas public interest groups were in favor of expanding HCA but against curtailing class location requirements.

PHMSA has carefully considered the input and comments. At this time PHMSA plans to propose an approach that balances the need to provide additional protections for persons within the potential impact radius (PIR) of a pipeline rupture (outside of a defined HCA), and the need to prudently apply IM resources in a fashion that continues to emphasize the risk priority of HCAs. PHMSA, therefore, is considering an approach that would require selected aspects of IM programs (namely, integrity assessments and repair criteria) to be applicable for non-HCA segments. For hazardous liquid pipelines, PHMSA would propose to apply these requirements to non-HCA pipeline segments. For gas transmission pipelines, PHMSA would propose to apply these requirements where persons live and work and could reasonably be expected to be located within a pipeline PIR. Under this approach, PHMSA would propose requirements that integrity assessments be conducted, and that injurious anomalies and defects be repaired in a timely manner, using similar standards in place for HCAs. However, the other program elements of a full IM program contained in 49 CFR part 192, subpart O, or 49 CFR 195.452 (as applicable) would not be required for non-HCA segments.

The Act also required the Secretary of Transportation to evaluate if expanding IM outside of HCAs, as discussed above, would mitigate the need for class location requirements. In August 2013, PHMSA published a notice in the **Federal Register** (78 FR 53086) soliciting comments on expanding IM program requirements and mitigating class location requirements. In addition, PHMSA held a Class Location Workshop on April 16, 2014, to discuss the notice and comments were received from stakeholders, including industry representatives, pipeline operators, state regulatory agencies, and the public. Overall, the majority of stakeholder responses suggested that PHMSA not change the current class location approach for class locations and class location changes as population increases used for establishing MAOP and operation and maintenance (O&M) surveys for existing pipelines. For new transmission pipelines, some industry groups and operators supported some type of bifurcated approach for existing and new pipelines as described above.

Based upon stakeholder input and findings from lessons learned, incident investigations, assessments, IM, and operating, maintenance, design and construction considerations, PHMSA believes the application of integrity management assessment and remediation requirements to MCAs does not warrant elimination of class locations. Class locations affect all gas pipelines, including transmission (interstate and intrastate), gathering, and distribution pipelines, whether they are constructed of steel pipe or plastic pipe. Class location is integral to determining MAOPs, design pressures, pipeline repairs, high consequence areas (HCAs), and operating and maintenance inspections and surveillance intervals. Class locations affect 12 subparts and 28 sections of 49 CFR part 192 for gas pipelines. The subparts and sections are listed and discussed in Sections 3.1.2.4 and 3.7.2.2. While assessment and remediation of defects on gas transmission pipelines is an important risk mitigation program, it does not adequately compensate for other aspects of class location as it relates to other types of gas pipelines and as it relates (for all gas pipelines) to the original pipeline design and construction such as the design factor, initial pressure testing, establishment of MAOP, O&M activities, and other aspects of pipeline safety, that are based on class location. Thus, PHMSA has determined not to eliminate class location requirements.

With respect to the application of gas transmission IM requirements to pipeline operating at less than 30% SMYS, as part of its consideration of the issues discussed in Topics J and N, PHMSA considered but rejected the suggestion that pipelines operating less than 30% SMYS be differentiated from those operating at higher stress levels.

Comments submitted for questions in Topic A.

A.1—Should PHMSA revise the existing criteria for identifying HCAs to expand the miles of pipeline included in HCAs? If so, what amendments to the criteria should PHMSA consider (e.g.,

increasing the number of buildings intended for human occupancy in Method 2?) Have improvements in assessment technology during the past few years led to changes in the cost of assessing pipelines? Given that most non-HCA mileage is already subjected to in-line inspection (ILI), does the contemplated expansion of HCAs represent any additional cost for conducting integrity assessments? If so, what are those costs? How would amendments to the current criteria impact state and local governments and other entities?

1. INGAA, industry consultant Thomas Lael, and a number of pipeline operators commented that modification of the HCA definition is unnecessary. They contended that the current definition is already risk-based and provides an effective basis for IM requirements along with a reasonable point from which to expand the application of IM principles by voluntary action. Accufacts commented that PHMSA should focus on closing gaps and loopholes rather than increasing HCA mileage, and that increasing covered mileage would only create the illusion of more safety.

2. AGA, APGA, and a number of gas distribution pipeline operators also opposed changes to the definition. They commented that other requirements of part 192 already address the primary threats for pipe outside HCA. They noted that much effort went into establishing the current definition, there is no safety rationale to abandon it, and change would be inconsistent with risk-based principles and would dilute safety efforts. AGA further noted that imprudent expansion would be contrary to Congressional intent, in that it would dilute the focus on densely populated and environmentally sensitive areas. AGA commented that PHMSA should make no change in this area before completing the related studies required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.

3. Taking a contrary position, a number of commenters not affiliated with the pipeline industry supported increasing the pipeline mileage classified as HCA. One private citizen suggested that all pipelines in cities with population greater than 100,000 should be classified as HCA. This commenter believes that existing regulations result in insufficient requirements for urban pipelines. Another citizen suggested that all high-stress lines with a ''receptor,'' which he defines as ''something which needs to be protected,'' should be assessed. If changes to the HCA definition are needed to accomplish this, then he contended those changes should be made. The Pipeline Safety Trust would strengthen IM requirements and expand them to all transmission pipelines, although they allow that the details could be different for pipelines not currently classified as HCA. PST believes this would be an effective way to identify and eliminate threats.

4. The Oklahoma Independent Petroleum Association (OKIPA) commented that any changes to the HCA definition must be supported by a scientifically-valid assessment of risks and a complete cost-benefit analysis.

5. The Iowa Association of Municipal Utilities commented that PHMSA should not revise the HCA definition without taking into account the differences between high-pressure transmission pipelines and low-pressure, low-risk lines that are also classified as transmission. IAMU reported ''transmission lines'' operated by Iowa Municipal Utilities are typically 2 to 4 inches in diameter and have potential impact radii less than 90 feet.

6. The Texas Pipeline Association and Texas Oil & Gas Association contended that expanding HCA pipeline mileage would increase assessment costs, particularly if the arbitrary requirement for reassessments every 7 years is not changed. These associations also believe that additional assessments will result in significant service interruptions. They suggested that assessment requirements be expanded to other pipelines, if needed, rather than changing the definition of HCA, contending that this would allow a more reasoned approach not burdened by the requirement for 7-year reassessments.

7. The Texas Pipeline Association, Texas Oil & Gas Association and several pipeline operators disagreed with the ANPRM assertion that most non-HCA transmission pipeline has been subject to ILI inspections. They noted much non-HCA pipeline has been pigged (*i.e.,* assessed using an in-line inspection tool) but that intrastate transmission pipelines are typically not piggable.

8. MidAmerican suggested that there is no reason to believe that changes to the HCA definition would improve safety. They also noted that the effects of other recent regulatory changes have not yet been realized and could mask any effect of changes in HCA. At the same time, the company noted that revising the definition of an HCA to encompass potential impact circles with 15 structures intended for human occupancy, vs. the current 20, would increase the amount of HCA mileage on its pipeline system by about 10 percent, contending that the safety benefit of such a change would be questionable. They suggested it would be better to focus on pipe in HCAs rather than adding lower-risk pipe, since part 192 already provides a good level of safety for all pipelines.

9. INGAA and a number of pipeline operators commented that increasing the amount of HCA mileage would add or increase costs for hundreds of state and local government agencies. The increases would result from increased demands for identification, certification, and compliance auditing.

10. Northern Natural Gas suggested that PHMSA consider expanding HCA coverage by modifying the specifics of Method 2 for defining HCAs over time. Changes could include reducing the number of structures in potential impact circles that define an HCA, reducing the number of people that defines an identified site, etc. The company believes this kind of change would have the benefit of continued use of the ''science'' represented by the C–FER Technologies circle for determining HCAs (see part 192, appendix E, figure E.I.A). Northern also suggested PHMSA define a time period for occupation of an identified site which, they contended, would eliminate the need to address locations where a gathering of people is truly transient.

11. TransCanada reported its belief that the current HCA criteria provide an appropriate risk focus. In support of this belief, they noted that only 3 percent of their US transmission pipeline mileage is in HCAs but this includes 45 percent of the population within a potential impact radius of their pipelines.

12. The Iowa Utilities Board opposed changes to the HCA criteria to encompass more mileage. IUB commented that such changes would divert resources from application to higher-risk pipeline segments and there has been no demonstration that non-HCA pipeline segments pose as much risk as those currently defined as HCA.

13. Two private citizens and the Commissioners of Wyoming County, Pennsylvania, suggested the existence of one structure intended for human occupancy within a potential impact circle should be sufficient to define an HCA. These commenters noted that catastrophic consequences (*i.e.,* loss of life) are still possible in such sparsely populated areas. The Commissioners noted homes in their jurisdiction generally did not encroach on the pipelines; the homes were there first and the pipeline encroached on what should have been a safe zone around the home. They implied pipeline operators should expect a higher burden to assure safety in such circumstances.

14. The Pipeline Safety Trust commented that there should be a single set of criteria defining HCAs and that these criteria should be known to the public. They contended the public currently has no information on the criteria defining HCAs.

15. The California Public Utilities Commission commented that HCA criteria should be revised to include more pipeline mileage and that method 2 (use of potential impact circles) should be eliminated.

16. The Alaska Natural Gas Development Authority suggested that the definition of an HCA should accommodate the phenomenon of rapid growth in previously rural areas. They noted that such growth has occurred within Alaska due, in part, to disposal of state lands.

17. NAPSR suggested that PHMSA require all transmission pipelines to meet Class 3 and 4 requirements and eliminate HCAs. NAPSR contended that focusing resources on higher-risk pipelines is bad public policy, since an accident anywhere poses a risk to public safety and reduces public confidence.

18. The Texas Pipeline Association, Texas Oil & Gas Association and several pipeline operators objected to the implication in the ANPRM that assessment costs have decreased. They contended that costs have actually increased due to such factors as operational cost escalation and increased costs to address cased pipeline segments.

19. INGAA and a number of pipeline operators contended that costs cannot be estimated accurately absent a specific regulatory proposal. They suggested that additional costs would be minimal if expanding HCA mileage results in actions similar to INGAA's Integrity Management—Continuous Improvement (IMCI) action plan, but that costs could be high if different requirements are imposed.

20. INGAA reported that a recent survey showed that its members' identified baseline IM assessments will cover 64 percent of members' pipeline mileage, only 4 percent of which is in HCAs. INGAA stated that these assessments will have covered 90 percent of the population within a potential impact radius of the pipelines.

21. Southwest Gas and Paiute provided cost estimates for conducting IM assessments on their pipeline systems: $45,000 per mile for direct assessment, up to $125,000 per mile for in-line inspection, and from $200,000 to $2 million per instance where changes need to be made to a pipeline to accommodate instrumented pigs.

22. The California Public Utilities Commission and MidAmerican commented that costs would increase if the changes suggested in the ANPRM were made, but they provided no specific estimates.

23. APGA noted that costs incurred by or passed on to municipal utilities are costs to local governments, since the utilities are, themselves, government agencies.

24. Paiute and Southwest Gas noted that costs to local governments, including preparation of permits, paving repairs, etc., can be high.

25. An anonymous commenter suggested that costs are not likely to increase much, since most operators already assess more than HCAs and IM has fostered growth in ILI vendors.

26. Kern River noted that its costs would not increase much, since the company is already under similar restrictive requirements via special permit.

27. Accufacts noted that safety is not free. They suggested that relative ranking of assessment methods, by cost, is not likely to have changed. They cautioned that costs used in cost-benefit analyses supporting any rules must be credible and should have an auditable trail available to the public. They suggested that serious accidents can be a ''cost'' of associated deregulation and lack of proper, effective, and efficient safety regulatory oversight for this critical infrastructure.

Response to Question A.1 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that the definition of HCAs is adequate, and does not propose to modify the definition of scope of HCAs in this proposed rulemaking. However, to afford additional protections to other segments along the pipeline, PHMSA is proposing to apply selected IM program elements (namely assessment and remediation of defects) to areas outside HCAs that are newly defined as MCAs. PHMSA believe this approach applies appropriate risk-based levels of safety.

A.2. Should the HCA definition be revised so that all Class 3 and 4 locations are subject to the IM requirements? What has experience shown concerning the HCA mileage identified through present methods (e.g., number of HCA miles relative to system mileage or mileage in Class 3 and 4 locations)? Should the width used for determining class location for pipelines over 24 inches in diameter that operate above 1000 psig be increased? How many miles of HCA covered segments are Class 1, 2, 3, and 4? How many miles of Class 2, 3, and 4 pipe do operators have that are not within HCAs?

A.3. Of the 19,004 miles of pipe that are identified as being within an HCA, how many miles are in Class 1 or 2 locations?

1. Industry trade associations, pipeline operators, and the Iowa Utilities Board objected to the suggestion all Class 3 and 4 locations should be treated as HCA. They noted class location does not have a direct relationship to risk. Small, low-pressure pipelines with no structures intended for human occupancy within the PIR (or for which the PIR is contained entirely within the right of way) could be Class 3 or 4 under current definitions. INGAA noted approximately 90 percent of Class 3 and 4 mileage not in HCA is presently assessed through over testing during IM assessments. Kern River commented that class location is an outmoded system that is confusing and unduly complex. Many of these commenters noted there is no demonstration of need for including all Class 3 and 4 areas, since existing HCA criteria adequately identify areas posing higher risks.

2. Public commenters took a contrary position, suggesting class locations are a reasonable basis for increasing HCA mileage. Pipeline Safety Trust and California Public Utilities Commission commented all Class 3 and 4 locations should be HCA. They noted these are all highly populated areas putting more people at risk from pipeline accidents. CPUC noted the location of the significant 2010 pipeline accident in San Bruno, CA, could have avoided HCA classification if method 2 of the current definition had been used. An anonymous commenter supported this position, suggesting all Class 3 and 4 locations be treated as HCA and use of method 2 be restricted to Class 1 and 2 locations; this commenter contended use of method 2 to exclude some portions of Class 3 and 4 locations from HCA classification is inappropriate. This commenter further suggested the definition of Class 4 locations be revised, contending that the criterion of 4-story buildings being ''prevalent'' is not specific enough. Thomas Lael, an industry consultant, suggested all Class 4 locations should be HCA. Lael contended that this would be an easy change and would assure that the highest risk pipe is included.

3. NAPSR also suggested all Class 3 and 4 locations should be classified as HCA. NAPSR noted this is an alternative to their preferred solution of eliminating HCA and requiring that all transmission pipelines meet Class 3 and 4 requirements.

4. One public commenter went further. He suggested a new classification, Class 5, be established encompassing all pipeline in cities with populations of more than 100,000. He further suggested pipe in this new class should meet enhanced construction requirements, including required installation of automatic valves to isolate the pipeline in the event of an incident. He contended the existing regulations impose inadequate safety requirements on urban pipelines.

5. Accufacts suggested PHMSA focus first on closing loopholes and gaps rather than increasing HCA mileage. They commented increasing covered mileage without closing gaps would produce only the illusion of safety.

6. Northern Natural Gas suggested PHMSA consider an option of eliminating method 2 of the current HCA definition. They contended such a change would be easy to accomplish. At the same time, they questioned its efficacy, suggesting that it would result in limited or no increase in safety while imposing large costs.

7. INGAA and many pipeline operators objected to the suggested increase in the width of a class location unit for larger, high-pressure pipelines. They noted such a change would contravene the goals of IM and divert resources to pipe of lower risk, and pipe of this type posing high risks to population concentrations is already included as HCA based on its potential impact radius (which could be larger than 220 yards).

8. Here, again, public commenters generally took a contrary position. Pipeline Safety Trust suggested class location width should be at least as much as the potential impact radius. PST noted the PIR is intended to focus on areas requiring more protection while the existing class location width is arbitrary. Two private citizens agreed, one noting that large-diameter, high-pressure gathering pipelines in the Marcellus shale area are located slightly more than 220 yards from pre-existing houses and the other suggesting the class location width in higher-class areas should be 220 yards or the PIR, whichever is larger. Accufacts would go further, suggesting class location width be increased for large-diameter pipe regardless of pressure. Accufacts contended diameter is a more significant factor in determining the potential extent of post-accident damage than is pressure, noting the devastation resulting from the San Bruno accident extended to a much greater distance than the PIR. The Texas Pipeline Association and Texas Oil & Gas Association commented no change should be made until the studies required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 are completed.

9. INGAA and a number of pipeline companies submitted data concerning the amount of pipeline mileage currently in HCAs. INGAA's data is based on a survey of its members.

	INGAA	Paiute	SWGas	MidAmerican	Northern Natural
Class 1	475 miles HCA, 103,286 not.	1 mile HCA, 632 not	<1 of 382 miles are HCA.	0.63 miles HCA, 493.11 not.	0.1% of all mileage is HCA.
Class 2	535 miles HCA, 11,318 not.	0 miles HCA, 55 not	<1 of 20 miles are HCA	0.98 miles HCA, 101.92 not.	2% of mileage is HCA.
Class 3	4,100 miles HCA, 4, 646 not.	26 miles HCA, 142 not	185 miles HCA, 242 not.	44.96 miles HCA, 128.38 not.	27% of mileage is HCA.
Class 4	24 miles HCA, 5 not	None of less than 1 mile is HCA.	6 miles HCA, 5 not	no HCA mileage	no data reported.

10. Iowa Association of Municipal Utilities reported its members have zero HCA miles in any class. Most member transmission pipelines are in Class 1 locations. Members have 1.46 miles of Class 2 pipe and one mile in Class 3.

11. Ameren Illinois reported 3.5 of its 82 HCA miles are in Class 1 or 2.

12. Kern River reported it has 18.51 HCA miles in Class 1 and 3.14 miles in Class 2, of a total of 95.96 miles of HCA.

13. On March 15, 2012, PHMSA received a petition for rulemaking from the Jersey City Mayor's office contending that the current Class Location system ''does not sufficiently reflect high density urban areas, as the regulation fails to contemplate either (1) the dramatic differences in population densities between highly congested areas and other less dense Class 4 Locations, or (2) the full continuum of population densities found in urban areas themselves.'' Based on this, Jersey City petitioned PHMSA to add three (3) new Class Locations, which would be defined as follows:

- A Class 5 location is any class location unit that includes one or more building(s) with between four (4) and eight (8) stories;
- A Class 6 location is any class location unit that includes one or more building(s) with between nine (9) and forty (40) stories;
- A Class 7 location is any class location unit that includes at least one building with at least forty-one (41) stories.

Response to Questions A.2 and A.3 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that HCAs should not be based exclusively on class location. Similarly, PHMSA does not propose to define MCAs based on class location. PHMSA proposes that *moderate consequence area* means an onshore area that is within a potential impact circle, as defined in § 192.903, containing five (5) or more buildings intended for human occupancy, an occupied site, or a right-of-way for a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures,* and does not meet the definition of high consequence area, as defined in § 192.903. This assures a comparable level of safety for all pipelines, regardless of class location. As a result, PHMSA is not proposing to expand class locations in this proposed rule. The issue of expanding class locations is addressed in the class location report which is available for review in the docket while formulating comments.

A.4. Do existing criteria capture any HCAs that, based on risk, do not provide a substantial benefit for inclusion as an HCA? If so, what are those criteria? Should PHMSA amend the existing criteria in any way which could better focus the identification of an HCA based on risk while minimizing costs? If so, how? Would it be more beneficial to include more miles of pipeline under existing HCA IM procedures, or, to focus more intense safety measures on the highest risk, highest consequence areas or something else? If so why?

1. INGAA and several pipeline operators commented the method described in paragraph 2 in the

definition of HCA in § 192.903 appropriately focuses attention on at-risk populations. They contended that the method described in paragraph 1 in the definition of HCA in § 192.903 captures some inappropriate areas.

2. Texas Pipeline Association, Texas Oil & Gas Association, and Ameren Illinois contended the existing criteria do not capture areas not posing risk. They noted the criteria were based on the science of pipeline accidents to identify high-risk areas.

3. Paiute and Southwest Gas commented neither more HCA miles nor additional safety measures are needed. They contended existing criteria are adequate and rule provisions for preventive and mitigative measures and to consider pipe with similar conditions when anomalies are found in HCA are sufficient to address non-HCA pipeline segments.

4. APGA recommended the regulations be modified to treat transmission pipelines operated by local distribution companies, most of which operate at less than 30 percent SMYS, under distribution integrity management rather than transmission IM. APGA suggested this is an optimum time to make this change, which was discussed in the phase 1 work leading up to the distribution IM rule. Atmos agreed, noting failure by leakage rather than rupture, similar to distribution pipelines, is much more prevalent for this low-stress pipeline and it thus poses much lower risks.

5. Northern Natural Gas suggested PHMSA revisit its treatment of ''well defined areas'' that constitute identified sites. They contended current practice treats an entire area as an identified site even if only an unoccupied corner is within the PIR and persons congregating are outside that critical radius.

6. MidAmerican suggested PHMSA consider adding a multiplier to the PIR equation for higher-stress pipelines. They contended this could capture more high-risk pipe without adversely affecting low-stress pipelines that pose considerably less risk.

7. Atmos commented no change should be made which would increase the amount of HCA mileage, contending that this would dilute the current focus on high-risk pipe.

8. INGAA and several of its members suggested PHMSA rely on its Integrity Management—Continuous Improvement (IMCI) initiative to address pipeline in non-HCA areas.

Response to Question A.4 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that the existing method for identifying HCAs and calculating PIR is appropriate and is not proposing a change to either. However, PHMSA disagrees that existing requirements are sufficient for non-HCAs segments. PHMSA believes non-HCA segments where people congregate should be afforded additional protections. Therefore, PHMSA is proposing that selected IM program elements (assessment and remediation of defects) be applied to MCAs.

A.5. In determining whether areas surrounding pipeline right-of-ways meet the HCA criteria as set forth in part 192, is the potential impact radius sufficient to protect the public in the event of a gas pipeline leak or rupture? Are there ways that PHMSA can improve the process of right-of-ways HCA criteria determinations?

1. INGAA, AGA, GPTC and a number of pipeline operators contended the existing PIR criteria are sufficiently conservative. They noted the criteria were derived from scientific analysis of the consequences of past pipeline accidents. Texas Pipeline Association and Texas Oil & Gas Association commented there is no reason to modify the PIR criteria or to establish alternate criteria to define HCAs; they contended there is no evidence the current PIR definition has provided insufficient protection to the public.

2. One private citizen and Alaska's Department of Natural Resources suggested HCA criteria should be revised to consider parallel pipelines in a common right of way, contending that an accident on one pipeline could impact adjacent lines, thus compounding consequences. They further suggested requirements for pipelines in common rights of way should include minimum spacing between the pipelines.

3. An anonymous commenter suggested plume releases be considered to determine which pipeline segments can affect an HCA, contending that this would be a good practice.

4. AGA, Texas Pipeline Association, Texas Oil & Gas Association, GPTC, and several pipeline operators cautioned against use of the term ''right of way'' in the context of defining HCAs. They noted this term is imprecise and the actual location of the pipeline, rather than an ill-defined right of way, is the important factor in evaluating risk.

5. Accufacts, INGAA, and numerous pipeline operators cautioned against discussions that imply that the PIR concept is applicable to considerations of risk from pipeline leaks. These commenters noted that the PIR is based on the consequences of a pipeline rupture and resulting conflagrations and was never intended to address leaks not involving fires.

6. ITT Exelis Geospatial Systems, a company providing services to the pipeline industry, noted accurate location of a pipeline is as important to assuring adequate protection of high-risk populations as is the calculation of PIR.

7. Accufacts suggested PHMSA require a report of the actual impact area, including aerial photographs, within 24 hours of any pipeline rupture. Accufacts contended this data would provide a further basis for continuing review of PIR adequacy.

Response to Question A.5 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that the existing definition of PIR is appropriate at this time. PHMSA believes that adjusting the PIR formula based on parallel pipelines in the right-of-way, or other right-of-way factors, are premature at this time. Also, PHMSA acknowledges that the PIR approach only applies such incidents resulting in explosions and fires. While certain gases might be better modeled using plume models, such models have not been carefully studied or developed. However, PHMSA plans to pursue (outside the scope of this rulemaking) additional incident reporting requirements for the purpose of further evaluating the extent of damage following incidents.

A.6. Some pipelines are located in right-of-ways also used, or paralleling those, for electric transmission lines serving sizable communities. Should HCA criteria be revised to capture such critical infrastructure that is potentially at risk from a pipeline incident?

1. INGAA, AGA, Texas Pipeline Association, Texas Oil & Gas Association, and many pipeline operators objected to any potential inclusion of ''critical infrastructure'' in HCA criteria. They noted there is no history of problems caused by impacts on infrastructure, there is little public risk involved, data regarding such infrastructure would be difficult for pipeline operators to obtain, and issues involving potential interactions with critical infrastructure are usually addressed during pipeline planning and construction.

2. GPTC and Nicor recommended HCA criteria not be revised to include critical infrastructure. They noted the intent of defining HCAs is to address risk to life and not property damage and damages to local infrastructure are unlikely to result in consequences similar to those that could affect population concentrations near the

pipeline. Atmos agreed, noting planning for accident-caused outages is a responsibility of electric system operators.

3. Pipeline Safety Trust, Accufacts, NAPSR, Alaska Department of Natural Resources, California Public Utilities Commission and ITT Exelis Geospatial Systems recommended critical infrastructure be included among HCA-defining criteria. Several of these commenters suggested infrastructure beyond electric transmission be considered, including, for example, water and sewage treatment plants, fire stations, and communications facilities. The commenters noted damages to critical infrastructure can lead to cascading effects and additional public safety consequences. ITT Exelis acknowledged these considerations may be secondary to loss of life but contended they are still important to public safety.

4. Northern Natural Gas, Kern River, MidAmerican, Paiute, and Southwest Gas noted determining the impact of damages to infrastructure items is complex. These commenters suggested it is not practical to define what constitutes ''critical'' infrastructure, from a public safety standpoint, on a generic basis. They recommended PHMSA leave consequence determination to operators, as part of their risk assessments, providing additional guidance for such considerations if needed.

5. An anonymous commenter suggested more frequent tests of cathodic protection and coating surveys be required in areas potentially subject to induced currents from nearby electric transmission infrastructure.

Response to Question A.6 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that there have been relatively few pipeline incidents that have had a major impact on critical infrastructure. PHMSA also acknowledges that the PIR formula was developed based on life safety (*i.e.,* heat flux that result in fatalities). However, PHMSA is also aware of recent incidents that, among other consequences, damaged and caused temporary closure of interstate highways. Among them are the 2012 incident at Sissonville, WV and the 2010 incident at New Delhi, LA, which also resulted in one fatality. Even though PHMSA is not proposing to revise the HCA criteria or the PIR formula, PHMSA is proposing to include major highways in the MCA criteria.

A.7. What, if any, input and/or oversight should the general public and/or local communities provide in the identification of HCAs? If commenters believe that the public or local communities should provide input and/or oversight, how should PHMSA gather information and interface with these entities? If commenters believe that the public or local communities should provide input and/or oversight, what type of information should be provided and should it be voluntary to do so? If commenters believe that the public or local communities should provide input, what would be the burden entailed in providing provide this information? Should state and local governments be involved in the HCA identification and oversight process? If commenters believe that state and local governments be involved in the HCA identification and oversight process what would the nature of this involvement be?

1. INGAA and its pipeline operator members commented no additional public involvement is needed. INGAA noted consultation is required under the current regulations, and it seldom identifies any relevant information. Additional involvement, INGAA contends, would likely lead to inconsistencies and would degrade the technical/scientific basis for determining HCAs.

2. AGA and several of its member companies suggested local government agencies should provide information when requested by pipeline operators. They contended additional required involvement would pose an additional burden on pipeline operators while adding no benefit. AGA noted information from its members suggests that local government agencies very rarely point out identified sites not otherwise known to the pipeline operator.

3. Texas Pipeline Association, Texas Oil & Gas Association, GPTC, Nicor, Ameren Illinois and Oleksa and Associates (a pipeline industry consultant) suggested further involvement of local governments not be required. These commenters contended pipeline operators have more relevant knowledge and involvement of inexperienced entities in identifying HCAs is more likely to result in confusion than useful information. The Texas associations suggested current public awareness requirements afford sufficient involvement of local agencies.

4. Accufacts noted local governmental agencies have maps identifying locations important to public safety and suggested these maps should be used by pipeline operators in HCA determinations. Accufacts believes this could assist operators in assuring consideration of accurate, complete, and current information.

5. Northern Natural Gas reported it has a phone number and email address that local residents and agencies can use to provide input to its HCA determinations. Northern further reported no HCAs have been identified from information provided via these avenues that were not otherwise known to the company.

6. Public commenters suggested local residents and government agencies should receive more information concerning pipelines and HCAs. One commenter suggested operators should provide copies of IM plans upon request, and should provide prior notification to residents within a PIR of assessments and a subsequent report of assessment results or problems otherwise identified. This individual also suggested locations of HCAs and assessment trend results should be provided to local communities upon request. The League of Women Voters of Pennsylvania suggested distribution integrity management plans should be readily available and the public should be involved in decisions related to those plans.

7. Pipeline Safety Trust commented public review should be part of any process by which PHMSA reviews or approves of HCA identifications.

8. Wyoming County Pennsylvania Commissioners suggested stakeholder meetings and public comment periods be required as part of HCA identification. They noted local residents know their communities better than others, including expected changes that could affect HCA identification.

9. AGA and several of its member operators recommended local governments play no role in oversight of HCA determinations. They contended this would increase burden and result in inconsistencies and confusion.

10. An anonymous commenter suggested existing public awareness contacts should be used to improve HCA determinations. The commenter expressed the belief this existing structure could allow low-cost involvement of local officials in such determinations.

11. The NTSB suggested PHMSA work with states to employ oversight of pipeline IM plans based on objective metrics. The NTSB noted this would be consistent with recommendation P–11–20 resulting from its investigation of the San Bruno, CA pipeline accident.

12. Iowa Association of Municipal Utilities noted local government employees are involved when HCA determinations are made by municipal utilities and further requirements for

local involvement would be inappropriate for such operators.

Response to Question A.7 Comments

PHMSA appreciates the information provided by the commenters. PHMSA is continuing to evaluate this aspect of integrity management but has not yet reached any conclusions. PHMSA may consider this input for future action, if applicable.

A.8. Should PHMSA develop additional safety measures, including those similar to IM, for areas outside of HCAs? If so, what would they be? If so, what should the assessment schedule for non-HCAs be?

1. Pipeline operators and their associations generally agreed additional measures were not needed outside HCA. INGAA and several transmission pipeline operators suggested operators be allowed to apply the principles of ASME/ANSI B31.8S voluntarily, as needed. INGAA noted this is the concept behind its Integrity Management—Continuous Improvement (IMCI) initiative.

2. AGA and a number of its member operators noted the regulations already require implementation of preventive and mitigative measures outside of HCA for low-stress pipe (§ 192.935(d)). These requirements include using qualified personnel to conduct work that could adversely affect the integrity of the covered segment, collecting excavation damage information, and participating in one-call systems.

3. Ameren Illinois and MidAmerican commented additional measures are not needed, because existing operations & maintenance requirements already assure integrity.

4. GPTC and Nicor agreed, noting it would be inappropriate to apply IM measures outside of HCA and existing requirements are assuring an adequate level of safety.

5. Atmos contended the existing provision requiring that operators evaluate and remediate non-HCA pipeline segments when corrosion is found during an IM assessment of a covered pipeline segment (§ 192.917(e)(5)) already provides that actions be taken to assure the integrity of non-HCA pipeline segments.

6. Texas Pipeline Association and Texas Oil & Gas Association would not object to a phased expansion of IM requirements provided that required assessment intervals are scientifically based. The associations noted Texas pipelines are already subject to the broader requirements of the Texas IM rule. They commented phased implementation would assure the next-highest risks are addressed first and would allow time for IM-support resources to grow.

7. Iowa Association of Municipal Utilities commented new requirements are not needed for its members' pipelines. These lines are small-diameter, low-pressure, odorized, and already pose low risk.

8. Northern Natural Gas suggested PHMSA expand the HCA definition gradually over time rather than imposing IM requirements outside HCA. Northern commented such an approach would retain and expand the focus on areas posing the highest risk.

9. Accufacts commented repair criteria, including required response times, and reporting of anomalies should be the same in- or outside HCA, since the progression of an anomaly to failure is unrelated to whether the anomaly exists within or outside of an HCA.

10. Pipeline Safety Trust suggested non-HCA pipeline segments should be subject to a baseline of IM requirements.

11. The Commissioners of Wyoming County Pennsylvania suggested PHMSA consolidate operators' best practices and require assessment of all pipe frequently enough to realize a benefit. They commented this approach would assure a consistent level of public protection regardless of the practices of individual pipeline operators.

12. California Public Utilities Commission noted this question would be moot if method 2 for defining HCA is eliminated.

Response to Question A.8 Comments

PHMSA appreciates the information provided by the commenters. Although most industry commenters did not support expansion of integrity management requirements outside HCAs, PHMSA believes additional protections are needed for pipeline segments where people are expected within the PIR. In this NPRM, PHMSA proposes an approach that balances the need to provide additional protections for persons within the potential impact radius (PIR) of a pipeline rupture (outside of a defined HCA), and the need to prudently apply IM resources in a fashion that continues to emphasize the risk priority of HCAs. The proposed regulation would require selected aspects of IM programs (namely, integrity assessments and repair criteria) to be applicable for selected non-HCA segments defined as MCAs. An MCA would be a segment located where persons live and work and could reasonably be expected to be located within a pipeline PIR. PHMSA would propose requirements that integrity assessments be conducted, and that injurious anomalies and defects be repaired in a timely manner, using similar standards in place for HCAs. However, the other program elements of a full IM program contained in 49 CFR part 192, subpart O would not be required for MCA segments.

A.9. Should operators be required to submit to PHMSA geospatial information related to the identification of HCAs?

1. Most industry commenters, including INGAA, AGA, and numerous pipeline operators supported this proposed requirement. They noted submission of this data will be required for PHMSA to comply with the mapping provisions of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.

2. Accufacts, Alaska Department of Natural Resources, California Public Utility Commission, and one private citizen agreed, suggesting PHMSA should know where HCAs are located and that this information is important to emergency responders. CPUC also suggested operators should be required to submit this information to State regulatory authorities as well.

3. Pipeline Safety Trust also supported this proposal, adding the information should be shared with the public.

4. League of Women Voters of Pennsylvania and Accufacts also supported making maps identifying pipeline locations, including HCA, available to the public.

5. Atmos, Northern Natural Gas, Kern River, Nicor, and GPTC opposed a requirement to submit this information. They noted this is a large amount of information which is available for audits and questioned how it would be used by PHMSA and how related security issues would be addressed.

6. Ameren Illinois suggested a requirement to submit HCA locations is not needed, since location data on the entire pipeline system must already be submitted to the National Pipeline Mapping System.

7. Texas Pipeline Association, Texas Oil & Gas Association, and MidAmerican agreed that providing HCA information as part of NPMS submissions is adequate. They noted this is consistent with Section 6 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.

Response to Question A.9 Comments

PHMSA appreciates the information provided by the commenters. Most commenters supported the submittal of HCA information in geospatial format. As noted by one commenter, this is required by the Act. Although outside

the scope of this rulemaking, PHMSA is pursuing data reporting improvements by proposing revisions to its currently approved information collection for the National Pipeline Mapping System. PHMSA has published several **Federal Register** notices and held several public workshops on the proposals.

A.10. Why has the number of HCA miles declined over the years?

1. Responses to this question consisted of speculation regarding reasons why the number of HCA miles may have declined. No commenters reported having specific data to describe the reducing trend.

2. AGA suggested pipe replacement, reductions in MAOP, and use of better data could be among the many reasons for a decline in HCA mileage.

3. INGAA speculated the reduction could be a result of operators changing from method 1 to method 2 to identify HCAs and abandoning or retiring older pipelines.

4. Texas Pipeline Association, Texas Oil & Gas Association, Atmos, and a private citizen agreed a change in the method for identifying HCAs is a likely reason for the decreasing mileage trend.

5. Northern Natural Gas commented changes in land use over time result in changes in the pipeline segments identified as HCA. Northern noted it has changed from method 1 to method 2 for identifying HCA but that the change had resulted in an increase in HCA mileage rather than a decrease. Kern River also reported that its HCA mileage is increasing, citing changes in land use along the pipeline as the reason for this change.

6. GPTC and Nicor suggested operational changes and removal of pipe from service could be the cause of the observed changes.

7. Iowa Utilities Board noted reductions in pressure and other operational changes can eliminate covered pipeline segments. IUB also suggested a change from method 1 to method 2 and better analyses of potential impact circles, etc. could have resulted in decreased HCA mileage.

8. MidAmerican noted its HCA mileage has fluctuated but remains relatively constant overall. They noted periodic fluctuations result from changes in various parameters that go into identifying HCAs.

9. A private citizen suggested operators may be buying properties within potential impact circles and razing them or that new pipelines in rural areas may be replacing current pipelines.

10. An anonymous commenter suggested HCA mileage is decreasing because operators are getting better at identifying HCAs. The commenter noted operators have been doing so for 9 years.

Response to Question A.10 Comments

PHMSA appreciates the information provided by the commenters. PHMSA considered this input in its evaluation mandated by the Act.

A.11. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible.

1. Accufacts commented property damage costs reported to PHMSA following pipeline incidents appear to be understated. Accufacts noted this raises serious questions about the validity of cost-benefit analyses performed using this data.

2. Iowa Association of Municipal Utilities commented the costs to comply with IM-like requirements are not justified for small, low-pressure transmission pipelines such as those operated by its members. Significant costs to develop IM plans, evaluate remote valves, and comply with other IM requirements must be passed on to a small rate base for many municipal utilities.

3. ITT Exelis Geospatial Systems suggested HCA criteria be revised and requirements for protection of critical infrastructure and populated areas be made more prescriptive. They commented such changes would require that leak surveys be performed more frequently, providing improved safety.

4. ITT Exelis Geospatial Systems reported its leak detection systems, developed as part of research jointly sponsored with DOT and other agencies, could facilitate this testing and initial costs would be offset by longer term savings.

5. California Public Utilities Commission observed the public has indicated its desire for more prescriptive safety requirements.

Response to Question A.11 Comments

The Act requires that the Secretary of Transportation to evaluate whether integrity management requirements should be expanded beyond HCAs and whether such expansion would mitigate the need for class location requirements. The proposed rulemaking does not change the HCA definition. However, PHMSA is proposing pipeline assessment requirements in new § 192.710 for newly defined moderate consequence areas (MCAs). PHMSA is also proposing new requirements in § 192.607 for verification of pipeline material and § 192.624 for MAOP verification would also apply to MCAs. PHMSA performed a Preliminary Regulatory Impact Analysis, using the best available data and information. It is available on the docket and PHMSA invites comments on the PRIA.

B. Strengthening Requirements To Implement Preventive and Mitigative Measures for Pipeline Segments in HCAs

Section 192.935 requires gas transmission pipeline operators to take additional measures, beyond those already required by part 192, to prevent a pipeline failure and to mitigate the consequences of a potential failure in a HCA following the completion of a risk assessment. Section 192.935(a) specifies examples of additional measures, which include, but are not limited to installing automatic Shut-off Valves or Remote Control Valves; installing computerized monitoring and leak detection systems; replacing pipe segments with pipe of heavier wall thickness; providing additional training to personnel on response procedures; conducting drills with local emergency responders; and implementing additional inspection and maintenance programs. In the ANPRM, PHMSA expressed concern that these additional measures are not explicitly required. As a result, operators may not be employing the appropriate additional measures as intended. Section 192.935(b) specifies that operators are also required to enhance their damage prevention programs and to take additional measures to protect HCA segments subject to the threat of outside force damage (non-excavation). PHMSA also noted in the ANPRM that the provisions in § 192.935 only apply to HCAs and that the expansion of the HCA definition would increase the mileage of pipelines subject to § 192.935. Further, PHMSA acknowledged the consideration of expanding preventive and mitigative measures to pipelines outside of HCAs. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic B

1. INGAA suggested PHMSA can substantially improve prevention and mitigation of accidents caused by excavation damage by facilitating full implementation of state damage prevention programs. INGAA further suggested PHMSA actively promote the use of 811 one-call programs. INGAA noted excavation damage remains the most prevalent cause of serious incidents and failure to notify is a primary cause of these incidents. Many pipeline operators supported the INGAA comments.

2. INGAA, supported by many of its pipeline operator members, noted it has a policy goal to apply integrity management principles, voluntarily, to pipelines beyond HCAs. Their goal is to address 90 percent of the population near pipelines by 2020 and 100 percent by 2030 through application of appropriate principles from ASME/ANSI B31.8S.

3. AGA supported application of IM principles, but not assessment requirements, outside HCAs. AGA commented requiring operators to understand and address risks is a good application of IM principles. Many pipeline operators supported the AGA comments.

4. AGA commented the ANPRM incorrectly states that § 192.935 applies only to pipe within HCAs. AGA noted paragraph (d) of that section applies to low-stress pipe in Class 3 and 4 areas that is not in HCAs.

5. California Public Utilities Commission suggested pipelines installed prior to the promulgation of federal pipeline safety requirements (so-called ''pre-code'' pipe) be reassessed more frequently.

6. Alaska Natural Gas Development Authority commented Alaska's experience indicates improved pipeline design and construction requirements are needed to assure pipeline integrity. These would include stronger pipe, improved requirements for mainline valves (including spacing and remote operation), and improved corrosion control. The Authority also commented that design requirements need to accommodate likely changes in class location, noting that explosive growth in some Alaska areas has resulted in rapid changes from Class 1 to Class 3.

7. One private citizen suggested some level of assessment should be required for all pipelines.

8. Another private citizen suggested integrity management plans for densely populated areas (Class 4 and Class 5—a new class suggested by the commenter encompassing cities with population greater than 100,000) should be developed in consultation with local emergency responders. The commenter further suggested these plans should be available at the FERC environmental impact study stage and should be reviewed with local authorities.

9. Another private citizen suggested information should be shared across pipeline operators, noting this would augment the knowledge of individual companies and improve safety. Similarly, the commenter suggested PHMSA require operators to submit a list of preventive and mitigative measures that have been implemented and reports of their effectiveness. The commenter noted PHMSA should know this information but apparently does not, as indicated by questions posed in this ANPRM (particularly questions B.1 and B.2).

Comments Submitted for Questions in Topic B

B.1. What practices do gas transmission pipeline operators now use to make decisions as to whether/which additional preventive and mitigative measures are to be implemented? Are these decisions guided by any industry or consensus standards? If so, what are those industry or consensus standards?

1. Most industry commenters indicated ASME/ANSI B31.8S is a common standard used to guide decisions concerning preventive and mitigative measures. INGAA suggested enhancing this standard would be the best approach to provide additional guidance for selection and implementation of these measures. Other commenters also cited the GPTC Guide as a useful guideline. INGAA listed other standards used by pipeline operators, including:

- Common Ground Alliance Best Practices
- Pipelines and Informed Planning Alliance Recommended Practices
- API–RP 1162—Public Awareness Programs,
- API–RP 1166—Excavation Monitoring
- NACE SP0169, other associated NACE standards
- Gas Piping Technology Committee guidance materials
- RSTRENG—A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe
- INGAA Foundation Guidelines for Evaluation and Mitigation of Expanded Pipes

AGA also noted that operators are guided by their own risk assessments. Many pipeline operators supported the INGAA and AGA comments.

2. Northern Natural Gas reported it does not rely on a specific consensus standard to select preventive and mitigative measures. It relies, instead, on company subject matter experts guided by statistical analyses of their risk model.

3. Paiute and Southwest Gas reported they use an algorithm combining risk scores, threats, and the value of specific measures. Company engineers analyze the results of applying this algorithm and develop preventive and mitigative measure implementation plans.

4. An anonymous commenter noted many pipeline operators are implementing actions that could be considered preventive and mitigative measures but these actions may not be identified as such if they are implemented as part of operations and maintenance activities and not specifically included in IM plans.

5. INGAA suggested PHMSA would benefit by applying ASME/ANSI B31.8S in its IM enforcement activities.

B.2. Have any additional preventive and mitigative measures been voluntarily implemented in response to the requirements of § 192.935? How prevalent are they? Do pipeline operators typically implement specific measures across all HCAs in their pipeline system, or do they target measures at individual HCAs? How many miles of HCA are afforded additional protection by each of the measures that have been implemented? To what extent do pipeline operators implement selected measures to protect additional pipeline mileage not in HCAs?

1. INGAA reported many pipeline operators have implemented additional preventive and mitigative measures. INGAA does not keep data on this and did not provide examples. Some pipeline operators submitted examples in support of the INGAA comments. Preventive and mitigative measures cited in these examples include:

- Additional reconnaissance (after seismic events, floods, etc.);
- Concrete mats over pipelines in areas particularly susceptible to excavation damage;
- Encroachment sensors;
- Remotely operated valves;
- Removal of casings;
- Completion of CIS surveys;
- Clearing of rights-of-way;
- Derating/deactivating of pipelines;
- Relocation of pipelines;
- Increased inspection of river crossings;
- Lowering of shallow pipelines;
- Installation of additional marker posts;
- Revising marking standards for locates;
- Completing depth-of-cover surveys;
- Enhancing right-of-way patrols.

In addition, one pipeline operator reported augmented implementation of many requirements of part 192 and implementation of some requirements (*e.g.*, operator qualification) beyond their specified bounds.

2. AGA also reported many additional preventive and mitigative actions have been implemented but, again, does not keep data on them. Examples cited by AGA and its operator members included increased use of indirect inspection tools, increased patrols, and investigation of apparent instances of encroachment.

3. GPTC reported data is not collected concerning voluntary measures.

4. Texas Pipeline Association and Texas Oil & Gas Association similarly reported that they do not collect this data, and there was only limited response to a survey of their operators regarding this question. The associations reported their understanding that measures are not generally implemented system-wide.

5. California Public Utilities Commission reported some CA operators are stationing personnel at the location of excavations near transmission pipelines. CAPUC also noted California's one-call law requires a mandatory field meeting before any excavation near a transmission pipeline operating above 60 psi.

6. An anonymous commenter suggested operators avoid implementing non-required actions for fear they will lead to new requirements.

7. Industry comments indicated data is not collected concerning the extent of implementation of voluntary preventive and mitigative measures. Some measures are implemented in specific HCAs while others may be implemented more broadly across a pipeline system. The extent depends largely on the threat being addressed and its prevalence.

8. Northern Natural Gas reported it has implemented voluntary measures outside HCA, citing as examples high-visibility markers in Class 1 areas and use of LIDAR leak detection. Northern reported broad implementation of voluntary measures is more prevalent than site specific use.

9. MidAmerican reported virtually all of its transmission pipeline mileage is subject to at least one preventive and mitigative measure.

10. Paiute reported nine measures are applied to all of its 856 miles of transmission pipeline while 13 are applicable to all 27 miles of HCA.

11. Similarly, Southwest Gas has implemented nine measures on 841 miles and 13 on all 191 miles of HCA.

12. AGA reported that approximately 195,000 non-HCA miles have been assessed, generally through assessing pipe upstream and downstream of the HCA segment.

B.3. Are any additional prescriptive requirements needed to improve selection and implementation decisions? If so, what are they and why?

1. Industry commenters unanimously agreed no new prescriptive requirements are needed. INGAA pointed out selection of preventive and mitigative measures is based on criteria in consensus standards and operator judgment. INGAA contended this allows appropriate customization and results in improved safety. AGA agreed, noting operators are in the best position to decide what is needed for their pipeline systems. GPTC stated that its Guide is sufficient, and there has been no demonstrated safety need for additional requirements. Several pipeline operators suggested conducting assessments and making repairs provides the most effective safety improvement.

2. Paiute and Southwest Gas suggested a best practices workshop to share industry experience could be beneficial.

3. Accufacts suggested additional prescriptiveness is needed to guide decisions regarding remote and automatically operated valves in HCA.

4. The Alaska Department of Natural Resources would suggest signoff by a professional engineer on preventive and mitigative action decisions.

5. The NTSB recommended improved use of metrics in inspection protocols, citing their recommendations P–11–18 and 19.

6. One private citizen suggested the lack of specifically-required actions in the regulations represents a deficiency in the pipeline safety regulatory program. The commenter suggested the extent of operator judgment be limited and that state and local officials should participate in developing a list of applicable preventive and mitigative actions.

7. An anonymous commenter suggested including more examples of preventive and mitigative actions in the regulations would help guide operator consideration of appropriate actions. The commenter also suggested operators be required to update their risk analyses, and selection of preventive and mitigative actions, more frequently including after changes in their pipeline systems or the occurrence of significant events.

B.4. What measures, if any, should operators be required explicitly to implement? Should they apply to all HCAs, or is there some reasonable basis for tailoring explicit mandates to particular HCAs? Should additional preventative and mitigative measures include any or all of the following: Additional line markers (line-of-sight); depth of cover surveys; close interval surveys for cathodic protection (CP) verification; coating surveys and recoating to help maintain CP current to pipe; additional right-of-way patrols; shorter ILI run intervals; additional gas quality monitoring, sampling, and inline inspection tool runs; and improved standards for marking pipelines for operator construction and maintenance and one-calls? If so, why?

1. INGAA, supported by many of its pipeline operator members, commented prescriptive requirements are not needed. INGAA contended prescriptive requirements are neither effective nor efficient and that ASME/ANSI B31.8S and the GPTC Guide provide sufficient guidance.

2. AGA commented one-call requirements and the actions required by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 are the only actions that should be required on a system-wide basis. AGA further suggested it could be appropriate to apply the additional measures required of low-pressure pipelines in § 192.935(d) to pipelines operating above 30 percent SMYS.

3. Texas Pipeline Association and Texas Oil & Gas Association recommended no new requirements be adopted applying specific preventive and mitigative actions throughout pipeline systems. The associations noted part 192 already requires application of some measures throughout pipeline systems and expressed their conclusion these already-specified measures are sufficient.

4. MidAmerican commented requiring application of specified measures throughout pipeline systems would provide a disincentive for the application of other measures which could be more appropriate.

5. The NTSB recommended requirements for leak detection in SCADA systems should be improved, citing their recommendation P–11–10.

6. California Public Utilities Commission recommended operators be required to station stand-by personnel at excavations near transmission pipelines and operator procedures should specify the actions these stand-by personnel must take. CPUC further suggested these standby activities should be a covered task under operators' personnel qualification programs.

7. Pipeline Safety Trust recommended PHMSA mandate the NTSB recommendations, noting many are similar to the specific measures suggested in this question. PST further commented operators should not be allowed sufficient latitude to render a regulation meaningless.

8. An anonymous commenter suggested the regulations should not specify particular preventive and mitigative measures but should emphasize consideration of potential accident consequences when selecting actions. The commenter noted there are too many variables to specify particular actions in regulation.

9. A private citizen suggested operators should be required to conduct drills with local responders periodically as part of their integrity management programs. The commenter noted such drills would improve coordination and would validate the ability to respond in the event of an emergency.

10. A private citizen suggested stronger enforcement is needed based on the belief that operators should already be taking many of the actions suggested in this question.

11. With respect to the specific actions suggested in this question:

a. Line-of-sight markers: National Utility Locating Contractors Association recommended line-of-sight markers be required, noting that they would reduce the instances of excavators failing to call for a locate, which the Common Ground Alliance's Damage Information Reporting Tool (DIRT) continues to indicate is a major cause of excavation damage. The Association further recommended the message on markers should be visible from all angles, noting that most current markers are only visible from two directions. The Commissioners of Wyoming County Pennsylvania, and MidAmerican suggested line-of-sight markers should be required, noting that they are a low-cost good practice for improving safety. An industry consultant disagreed, noting installation would be impractical in many areas where the sight line is obscured by crops, terrain, etc.

b. Depth of cover: MidAmerican opposed required depth of cover surveys, commenting they are not a good indicator of likely damage and such surveys are inherently inaccurate. Texas Pipeline Association and Texas Oil & Gas Association suggested compliance with depth of cover requirements over time is impractical. They noted operators do not have full control over rights of way and that owners can make changes. For example, a landowner may pave an area following grading which reduces the depth of cover. California Public Utilities Commission recommended depth of cover surveys be required wherever external corrosion direct assessment is applied and where vehicles or other loads capable of damaging the pipeline have access to the surface over the pipeline. Wyoming County Pennsylvania's Commissioners suggested depth of cover surveys be required as a good safety practice.

c. Close interval surveys: MidAmerican recommended against requiring these surveys. The company noted they are only one means of determining the adequacy of cathodic protection. The Commissioners of Wyoming County Pennsylvania recommended such surveys be required as a good safety practice.

d. Coating surveys and re-coating: MidAmerican opposed a requirement for coating surveys, noting holidays are found and repaired through in-line inspection and external direct assessment. The company further noted pipe replacement is often a superior repair to recoating. The Wyoming County Commissioner commented periodic coating surveys are a good practice and recommended that they be required.

e. Additional right of way patrols: MidAmerican and the Wyoming County Commissioners agreed increased frequency of patrols would be appropriate. MidAmerican noted patrols are a relatively low cost action that generates useful data.

f. Shorter ILI intervals: MidAmerican opposed shorter intervals, noting many lines cannot accommodate in-line inspection or more frequent runs. The Wyoming County Commissioners argued that frequent assessment is a good practice that should be required.

g. Additional gas quality monitoring: MidAmerican opposed such a requirement, arguing it would be redundant for distribution pipeline operators receiving gas from suppliers. The Wyoming County Commissioners argued frequent gas monitoring would be a good practice.

h. Improved pipeline marking standards: MidAmerican agreed implementing new marking standards would be a low cost action. Wyoming County again noted this is a good practice.

B.5. Should requirements for additional preventive and mitigative measures be established for pipeline segments not in HCAs? Should these requirements be the same as those for HCAs or should they be different? Should they apply to all pipeline segments not in HCAs or only to some? If not all, how should the pipeline segments to which new requirements apply be delineated?

1. INGAA, supported by many of its member companies, argued preventive and mitigative measures should be applied to non-HCA areas on a risk basis rather than by prescriptive requirement. INGAA commented this is a more effective and efficient means of increasing pipeline safety.

2. AGA commented codifying different requirements for non-HCA areas would likely cause confusion and extending existing IM requirements to non-HCA areas would create an enormous burden for PHMSA and states. AGA noted the NTSB has already questioned the ability of regulators to apply the existing IM inspection protocols to HCA mileage. AGA recommended one-call and the actions required by statute be the only additional measures required system-wide.

3. GPTC, Texas Pipeline Association, Texas Oil & Gas Association, and two pipeline operators opposed requirements for preventive and mitigative actions in non-HCA areas. These commenters argued it is important to allow pipeline operators the flexibility to select actions that are appropriate to their circumstances and implementing actions required arbitrarily would be expensive and ineffective.

4. Northern Natural Gas suggested PHMSA expand the HCA definition gradually over time rather than imposing IM requirements outside HCA. Northern commented such an approach would retain and expand the focus on areas posing the highest risk.

5. MidAmerican opposed additional requirements for preventive and mitigative actions, noting all pipeline is covered by other requirements in part 192 and it is better to focus enhanced requirements on areas posing highest risk.

6. AGA commented measures required in HCA should always be equal to or more stringent than measures required outside of HCA. AGA noted this is a fundamental principle of integrity management: Focusing on areas posing higher risks.

7. Ameren Illinois and an anonymous commenter suggested better enforcement and/or specificity for provisions requiring operators consider other areas of their systems when problems are discovered would be more effective than requiring preventive and mitigative measures outside HCA.

8. ITT Exelis Geospatial Systems commented requirements should be the same in- or outside HCA. They contended non-HCA areas are not monitored for leakage as often as Class 3 and 4 locations. They suggested their LIDAR system would allow effective and efficient leak surveys in all locations.

9. A public citizen recommended exposed pipe be wrapped in bright colors and protected from damage whether inside or outside of HCA. The commenter suggested analysis of data from CGA's Damage Information Reporting Tool would be an effective preventive measure.

B.6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible.

In addition, PHMSA requests commenters to provide information and supporting data related to, among other factors, the potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.

1. Northern Natural Gas reported the additional cost of preventative and mitigative measures it employs, including instrumented aerial leakage surveys, close-interval surveys, additional mailings and additional signage, has been approximately $950,000. Northern further reported the approximate cost of conducting assessments through in-line inspection or pressure testing for all high-consequence areas every seven years is $45,000,000 and reduction of the inspection interval would increase the cost accordingly.

Response to Topic B comments

Section 5 of the Act requires that the Secretary of Transportation complete an evaluation and issue a report on whether integrity management requirements should be expanded beyond HCAs and whether such expansion would mitigate the need for class location requirements. Aspects of this topic that relate to applying a risk analysis to determine additional preventive and mitigative measures for non-HCA pipeline segments will be addressed later, pending completion of the evaluation and report. PHMSA will review the comments received on this topic and will address them in the future in light of these statutory requirements.

Section 3 of the Act requires that the Secretary of Transportation complete an evaluation and issue a report on the impact of excavation damage on pipeline safety. Aspects of this topic that relate to additional preventive and mitigative measures for damage prevention will be addressed after completion of the evaluation and report. PHMSA will review the comments received on this topic and will address them in the future in light of this evaluation and report.

Section 6 of the Act requires that the Secretary of Transportation provide guidance on public awareness and emergency response plans. Aspects of this topic that relate to additional preventive and mitigative measures for public awareness and emergency response will be further evaluated in conjunction with this statutory mandate. PHMSA will review the comments received on this topic and will address them in the future in light of this evaluation.

Two specific areas of preventive and mitigative actions addressed in the IM requirements (49 CFR 192.935) are leak detection and automatic/remote control valves. The IM rule does not require specific measures be taken to address these aspects of pipeline design and operations, but does include them among candidate preventive and mitigative measures operators should consider. Both of these topics are the subject of recommendations that the NTSB made (recommendations P–11–10 and P–11–11) following the San Bruno explosion. In response to these recommendations, PHMSA conducted a public workshop on March 27, 2012, to seek stakeholder input on these issues, and is sponsoring additional research and development to further inform PHMSA's response on these issues. Aspects of this topic that relate to leak detection and automatic/remote control valves will be addressed after completion and evaluation of the above activities. PHMSA will review the comments received on leak detection and automatic/remote control valves and will address them in the future in light of this evaluation.

PHMSA is proposing to add requirements for enhanced preventive and mitigative measures to address internal and external corrosion control. The intent of the IM rulemaking is to enhance protections for high consequence areas. PHMSA believes that enhanced requirements for internal corrosion and external corrosion control are prudent. To address internal corrosion, PHMSA is proposing specific requirements for operators to monitor gas quality and contaminants and to take actions to mitigate adverse conditions. To address external corrosion, PHMSA is proposing specific requirements for operators to monitor and confirm the effectiveness of external corrosion control through electrical interference surveys and indirect assessments, including cathodic protection surveys and coating surveys, to take actions needed to mitigate conditions that are unfavorable to effective cathodic protection, and to integrate the results of these surveys with integrity assessment and other integrity-related data. PHMSA addresses this topic in more detail in response to comments related to Topic I, Corrosion Control.

Note: Specific comments submitted for Topic B that are related to risk and integrity assessments are addressed under Topics E and G.

C. Modifying Repair Criteria

The existing integrity management regulations establish criteria for the timely repair of injurious anomalies and defects discovered in the pipe (49 CFR 192.933). These criteria apply to pipeline segments in an HCA, but not to segments outside an HCA. The ANPRM announced that PHMSA is considering amending the integrity management rule by revising the repair criteria to provide greater assurance that injurious anomalies and defects are repaired before the defect can grow to a size that leads to a leak or rupture. In addition, PHMSA is considering establishing repair criteria for pipeline segments located in areas that are not in an HCA in order to provide greater assurance that defects on non-HCA pipeline segments are repaired in a timely manner. The following are general comments received related to the topic and then comments related to the specific questions:

General Comments for Topic C

1. INGAA reported its members' commitment to apply ASME/ANSI B31.8S corrosion anomaly criteria both inside and outside of HCAs. INGAA noted that new research to refine and extend the technical bases for responding to corrosion anomalies identified primarily by ILI has been completed by Pipeline Research Council International, whose report was expected to be published in the first quarter of 2012. INGAA also reported a commitment to develop and use criteria for mitigation of dents, corrosion pitting, expanded pipe corrosion, and selective seam weld corrosion. Numerous pipeline operators supported INGAA's comments.

2. AGA suggested that ASME/ANSI B31.8S should be the basis for defining anomalies requiring remediation. Anomalies not meeting the criteria in that standard, in AGA's opinion, do not require repair. AGA further commented that risk prioritization of maintenance and anomaly response should not be regulated because operators are in the best position to know the factors influencing prioritization for apparently-similar anomalies. AGA also suggested that PHMSA review INGAA's paper ''Anomaly Response and Mitigation Outside of High Consequence Areas when Using in Line Inspection,'' dated May 30, 2010, as this paper forms the basis for current industry response outside of HCAs. Numerous pipeline operators supported AGA's comments.

3. Accufacts contended that there have been too many corrosion-caused ruptures occurring shortly after in-line

inspection runs and that this indicates the need for more prescriptive criteria for corrosion evaluation and remediation.

4. Alaska Department of Natural Resources commented that repairs should be made using permanent methods, and that clamps and similar repairs are not sufficient.

Response to General Comments for Topic C

PHMSA appreciates the information provided by the commenters. Because the current repair criteria only address corrosion metal loss as an immediate condition, PHMSA agrees that more prescriptive repair criteria are needed to address significant corrosion metal loss that does not meet the immediate repair criterion, similar to the hazardous liquid integrity management repair criteria at 49 CFR 195.452(h). In addition, other conditions that are not currently addressed in the repair criteria, such as stress corrosion cracking and selective seam weld corrosion, are addressed in ASME B31.8S and other sources, but not explicitly addressed in part 192. PHMSA is proposing to enhance the repair criteria for HCA segments and is also proposing to add specific repair criteria for pipeline in non-HCA segments. In general, PHMSA is proposing to add more immediate repair conditions and more one-year conditions for HCA segments. The additional criteria address conditions not previously addressed, such as stress corrosion cracking, and also include more specific one-year criteria for corrosion metal loss, based on the design factor for the class location in which the pipeline is located, to address corrosion metal loss that reduces the design safety factor of the pipe. PHMSA is also proposing to apply similar repair criteria in non-HCA segments, except that response times will be tiered, with longer response times for non-immediate conditions. PHMSA reviewed available industry literature, including ASME/ANSI B31.8S, in developing the proposed repair criteria. Specific aspects of the proposed rules are discussed in response to the specific questions for Topic C, below.

PHMSA has not addressed the specific procedures and techniques for performing repairs in this rulemaking, but may do so at a later date.

Comments Submitted for Questions in Topic C

C.1. Should the immediate repair criterion of failure pressure ratio (*FPR) ≤1.1 be revised to require repair at a higher threshold (i.e., additional safety margin to failure)? Should repair safety margins be the same as new construction standards? Should class location changes, where the class location has changed from Class 1 to 2, 2 to 3, or 3 to 4 without pipe replacement have repair criteria that are more stringent than other locations? Should there be a metal loss repair criterion that requires immediate or a specified time to repair regardless of its location (HCA and non-HCA)?*

1. INGAA, supported by numerous pipeline operators, commented the FPR criterion need not be changed, noting there have been no reported incidents due to the criterion being too lax. INGAA also objected to PHMSA's characterization of this issue, noting that repair criteria already exceed 1.1 FPR; the 1.1 FPR criterion in the regulations governs response to anomalies and not the criteria to which repairs must be made.

2. AGA, supported by numerous of its pipeline operator members, commented that the FPR criterion should not be changed. AGA contended that the criterion already provides a 10 percent safety margin and is based on sound engineering practices.

3. Northern Natural Gas and Kern River stated that conservatism is present in burst pressure calculations and in the measurement of anomalies (considering tool tolerance), providing a safety margin greater than 10 percent.

4. Accufacts argued against changing the FPR criterion, but suggested that PHMSA require operators to use better assumptions in their failure analyses. Accufacts suggested that the regulations should focus on preventing failures but that existing safety margins need not be increased.

5. Texas Pipeline Association, Texas Oil & Gas Association, Atmos, and MidAmerican opposed changes to this criterion. These commenters noted that experience through the baseline inspections has demonstrated the criterion is adequate and ASME/ANSI B31.8S remains a good guide for anomaly response. Atmos added that this criterion separates immediate repairs from scheduled repairs: It allows a risk-based focus on more serious anomalies but does not mean that anomalies providing more than 10 percent margin to burst pressure are never addressed.

6. California Public Utilities Commission suggested that the FPR criterion be increased to 1.25 times MAOP. CPUC noted that the 10 percent margin in the current criterion can be completely erased by the 10 percent margin to safety relief settings allowed by § 192.201.

7. INGAA commented that additional repair criteria are not needed. INGAA noted that §§ 192.485(a) and 192.713(a) already specify repair criteria applicable to pipe outside HCA. Numerous pipeline operators supported INGAA's comments.

8. AGA, supported by numerous of its pipeline operator members, suggested that safety margins for repairs need not be the same as those for new construction. AGA argued that the construction margins are intended to address potential unknowns and forces applied during construction, which are not applicable to repairs.

9. Accufacts, Northern Natural Gas, and an anonymous commenter agreed that repairs, once initiated, should meet new construction safety margins.

10. INGAA and several of its pipeline operator members argued that repair criteria should not be more stringent where class location has changed. INGAA noted that § 192.611 does not change the original design criteria for segments that have been subject to a change in class location and there is no incident experience suggesting that additional safety margin is needed in these cases.

11. Northern Natural Gas and Kern River argued against a change in repair criteria where class location has changed, noting that the likelihood of failure of an anomaly is not affected by the class location and that treatment in accordance with integrity management requirements already considers risk.

12. MidAmerican, Paiute, and Southwest Gas added that use of the factor failure pressure divided by MAOP in ASME/ANSI B31.8S already reflects any change in MAOP necessitated by a change in class location.

13. Accufacts commented that repair criteria should be commensurate with the more restrictive design criteria of higher class locations.

14. INGAA commented no new metal loss criterion is needed, noting that its members use HCA response criteria as a guide for responding to indications of metal loss outside of HCAs. Numerous pipeline operators supported INGAA's comments.

15. AGA commented any metal loss criterion should reflect current science and should be the same regardless of class location. AGA suggested that immediate response to any indication of a dent with metal loss is not needed, noting that there have been many examples of dents with metal loss not sufficient to require recalculating remaining strength. AGA also noted the external corrosion direct assessment standard requires a similar response regardless of whether an indication is in

or outside HCA. Numerous pipeline operators supported AGA's comments.

16. Accufacts encouraged PHMSA to establish a prompt-action criterion for wall loss inside or outside HCAs, suggesting the focus should be on preventing ruptures regardless of where they occur. Accufacts also cautioned PHMSA against accepting studies attempting to show that 80 percent wall loss is sometimes acceptable, and stated that continued operation with such wall loss is too risky for onshore pipelines.

Response to Question C.1 Comments

PHMSA appreciates the information provided by the commenters. The majority of comments supported no changes to the immediate repair criterion of predicted failure pressure of less than or equal to 1.1 times MAOP for HCAs, and PHMSA is not proposing to change this criterion; however, PHMSA is proposing several changes to enhance the repair criteria both for HCA segments and non-HCA segments. For immediate conditions, PHMSA proposes to add the following to the immediate repair criteria: Metal loss greater than 80% of nominal wall thickness, indication of metal-loss affecting certain types of longitudinal seams, significant stress corrosion cracking, and selective seam weld corrosion. These additional repair criteria would address specific issues or gaps with the existing criteria. The methods specified in the IM rule to calculate predicted failure pressure are explicitly not valid if metal loss exceeds 80% of wall thickness. Corrosion affecting a longitudinal seam, especially associated with seam types that are known to be susceptible to latent manufacturing defects such as the failed pipe at San Bruno, and selective seam weld corrosion are known near-term integrity threats. Stress corrosion cracking is listed in ASME B31.8S as an immediate repair condition, which is not reflected in the current IM regulations. PHMSA proposes to add requirements to address these gaps.

The current regulations include no explicit metal loss repair criteria, other than one immediate condition. The regulations direct operators to use Figure 4 in ASME B31.8S to determine non-immediate metal loss repair criteria. PHMSA now proposes to explicitly include selected metal loss repair conditions in the one-year criteria. These proposed criteria are consistent with similar criteria currently invoked in the hazardous liquid integrity management rule at 40 CFR 195.452(h). In addition, PHMSA proposes to incorporate safety factors commensurate with the class location in which the pipeline is located, to include predicted failure pressure less than or equal to 1.25 times MAOP for Class 1 locations, 1.39 times MAOP for Class 2 locations, 1.67 times MAOP for Class 3 locations, and 2.00 times MAOP for Class 4 locations in HCAs. Lastly, in response to the lessons learned from the Marshall, Michigan, rupture, PHMSA proposes to include any crack or crack-like defect that does not meet the proposed immediate criteria as a one year condition. PHMSA proposes to apply these same criteria as two-year conditions for non-HCAs.

PHMSA agrees with Accufacts' comment that the regulations should focus on preventing failures but that existing safety margins are adequate when properly applied. Therefore, the proposed rule does not propose to increase safety margins such as the design factor. PHMSA maintains that the proposed changes discussed above provide a tiered, risk-based approach to metal loss repair criteria and by requiring predicted failure pressures as a function of class locations does not compound safety margins. Counter to INGAA's and AGA's comments that repair criteria should not be more stringent where class location has changed, PHMSA believes the tiered approach to metal loss repair criteria, which is a function of class location, provides a logical framework to address the risk presented by these types of pipeline anomalies.

In conjunction with enhanced repair criteria, PHMSA is proposing specific new regulations to require that operators properly analyze uncertainties and other factors that could lead to non-conservative predictions of failure pressure, and time remaining to failure, when evaluating ILI anomaly indications. PHMSA specifically is proposing that operators must analyze specific known sources of uncertainty regarding ILI tool performance, anomaly interactions, and other sources of uncertainty when determining if an anomaly meets any repair criterion.

C.2. Should anomalous conditions in non-HCA pipeline segments qualify as repair conditions subject to the IM repair schedules? If so, which ones? What projected costs and benefits would result from this requirement?

1. INGAA suggested that new criteria are not needed, commenting that operators generally treat non-HCA anomalies in a manner similar to HCA anomalies, except for response time. INGAA stated that industry costs to address non-HCA anomalies should be nominal unless immediate response is required because this is consistent with current operator practice, which INGAA stated is to apply ASME/ANSI B31.8S response criteria for anomalies both inside and outside HCAs.

2. Texas Pipeline Association and Texas Oil & Gas Association commented that differing repair criteria, if any, should be based upon the population at risk, since there is no valid engineering basis for treating anomalies differently depending on location.

3. Atmos and Northern Natural Gas suggested that non-HCA anomalies should be treated like HCA anomalies, although additional schedule flexibility should be allowed. Northern reported that it applies HCA metal loss criteria everywhere because it is prudent, although response time differs for non-HCA anomalies. Northern reported that it has expended approximately $7.7 million on anomaly repairs, $7 million of which was outside an HCA.

4. Kern River agreed that IM schedules are too stringent to apply everywhere and providing schedule flexibility will reduce costs.

5. MidAmerican disagreed with the suggestion that non-HCA and HCA anomalies be treated alike. MidAmerican commented that it is illogical to back off from focusing sooner on anomalies that pose greater risks.

6. California Public Utilities Commission commented that all locations identified by the method described in paragraph 1 in the definition of HCA in § 192.903 should be subject to HCA repair criteria.

7. Pipeline Safety Trust, Accufacts, and NAPSR commented that the same repair criteria and response schedule should apply regardless of where an anomaly is located. These commenters contended that there is no logical justification for different treatment, that any risk to the pipeline and public safety should be resolved, and that a pipeline accident anywhere is seen by the public as a failure to exercise adequate control of pipeline safety. NAPSR, in particular, suggested that all anomalies should be repaired immediately, regardless of where they are located.

8. Iowa Utilities Board, Iowa Association of Municipal Utilities, GPTC, Nicor, Ameren Illinois and an anonymous commenter contended that HCA repair criteria should not be applied outside HCAs. These commenters noted that there has been no demonstrated safety need for new criteria, that non-HCA anomalies are adequately addressed under existing operations and maintenance requirements, and that the cost to apply HCA repair criteria everywhere is not justified. IAMU particularly noted that

existing requirements are adequate for small, low-pressure transmission pipelines such as those operated by its members.

9. A private citizen supported application of HCA repair criteria in non-HCA areas, particularly where there are ''receptors,'' which the commenter defines as ''something which needs to be protected.''

Response to Question C.2 Comments

PHMSA appreciates the information provided by the commenters. PHMSA proposes to modify the general requirement for repair of pipelines to include immediate repair condition criteria, one-year conditions, and monitored conditions. The definition of these conditions would be the same as the existing definitions for covered segments (*i.e.,* HCA segments) in the IM rule; however, PHMSA proposes that those conditions that must be repaired within one year in a HCA segment would be required to be repaired within two years in a non-HCA segment. Defects that meet any of the immediate criteria are considered to be near-term threats to pipeline integrity and would be required to be repaired immediately regardless of location.

PHMSA believes that establishing these non-HCA segment repair conditions are important because, even though they are not within the defined high consequence locations, they could be located in populated areas and are not without consequence. For example, as reported by operators in the 2011 annual reports, while there are approximately 20,000 miles of gas transmission pipe in HCA segments, there are approximately 65,000 miles of pipe in Class 2, 3, and 4 populated areas. PHMSA believes it is prudent and appropriate to include criteria to assure the timely repair of injurious pipeline defects in non-HCA segments. These changes will ensure the prompt remediation of anomalous conditions on all gas pipeline segments while allowing operators to allocate their resources to high consequence areas on a higher priority basis.

C.3. Should PHMSA consider a risk tiering—where the conditions in the HCA areas would be addressed first, followed by the conditions in the non-HCA areas? How should PHMSA evaluate and measure risk in this context, and what risk factors should be considered?

1. INGAA, and many pipeline operators, opposed the suggested tiering. They commented that anomalies meeting response criteria should be addressed in an appropriate time frame whether inside or outside HCAs.

2. AGA, supported by many of its operator members, suggested that PHMSA not adopt any risk tiering beyond the current requirements to focus first on HCA anomalies. AGA noted that outside factors, *e.g.,* permitting, affect the timing and the sequence of repairs.

3. Texas Pipeline Association and Texas Oil & Gas Association commented that PHMSA should allow risk tiering system-wide, not just in differentiating between responses in and outside HCA. The associations suggested that this could be an improvement to requirements addressing anomalies. At the same time, they noted the description in the ANPRM is sketchy and requested PHMSA propose specific requirements for comment.

4. Iowa Association of Municipal Utilities commented that no new requirements are needed, and that the existing requirements are sufficient for the small, low-stress transmission pipelines operated by its members.

5. Atmos commented that the risk tiering concept is confusing and stated that it was considered and rejected when the initial IM rules were promulgated.

6. Northern Natural Gas commented that allowing a longer response time for anomalies outside HCA would be a form of risk tiering. The company reported it has incorporated this practice in its procedures.

7. Accufacts agreed that a focus on HCA anomalies is needed but cautioned against ignoring anomalies outside HCAs. Accufacts noted the progression of an anomaly to failure does not depend on whether or not it is located in an HCA.

Response to Question C.3 Comments

PHMSA appreciates the information provided by the commenters. Current regulations do not prescribe response timeframes for anomalies outside HCAs. As stated by Northern Natural Gas, allowing a longer response time for anomalies outside HCAs (compared to response times for anomalies inside HCAs) would be a form of risk-tiering. PHMSA is proposing such an approach, which would establish three timeframes for performing repairs in non-HCA areas: Immediate repair conditions, 2-year repair conditions, and monitored conditions. These changes will ensure the prompt remediation of anomalous conditions on all gas pipeline segments, while allowing operators to allocate their resources to those areas that present a higher risk.

C.4. What should be the repair schedules for anomalous conditions discovered in non-HCA pipeline segments through the integrity assessment or information analysis? Would a shortened repair schedule significantly reduce risk? Should repair schedules for anomalous conditions in HCAs be the same as or different from those in non-HCAs?

1. INGAA commented that repair schedules outside HCAs should be similar to those in HCAs but should allow for more scheduling latitude. This comment was supported by comments received from many of its operator members. They also noted that adding requirements to repair non-HCA anomalies would significantly increase the number of required repairs and that an inappropriate requirement for rapid response would dilute the focus on risk-significant repairs. INGAA suggested that repair schedules should be more a function of anomaly growth rates than location along the pipeline. INGAA further suggested that inappropriately rapid response schedules would increase risk; experience shows that most anomalies that have been found and repaired are old, do not require a rapid response, and that mandating rapid response to such anomalies would necessarily dilute other safety activities.

2. Texas Pipeline Association and Texas Oil & Gas Association expressed doubt that significant risk reduction would result from shortened repair schedules, given the logistics and related work involved in repairs.

3. GPTC, Nicor, and an anonymous commenter objected to applying HCA repair criteria outside HCAs. They believe that the costs for such an approach are not justified and non-HCA anomalies are appropriately dealt with under operations and maintenance requirements and procedures.

4. Ameren Illinois, Paiute, and Southwest Gas agreed that prescriptive repair schedules are not needed outside HCAs. They expressed a belief that operators must have scheduling flexibility to accommodate the needs of their operations.

5. MidAmerican suggested that immediate repair criteria be applied both in HCAs and outside HCAs, but that other criteria be limited to HCAs.

6. Northern Natural Gas suggested that PHMSA should require operators to determine response schedules for non-HCA anomalies as part of this rulemaking.

7. Iowa Association of Municipal Utilities commented that the existing requirements are sufficient for the small, low-stress transmission pipelines operated by its members.

8. California Public Utilities Commission commented that all method

1 HCA locations should be subject to HCA repair criteria.

9. MidAmerican, Paiute, and Southwest Gas commented that shortened response schedules will not reduce risk. These operators suggested that response times should be based on risk rather than being established arbitrarily.

Response to Question C.4 Comments

PHMSA appreciates the information provided by the commenters. PHMSA believes repair schedules outside HCAs should be similar to those in HCAs but should allow for more scheduling latitude. PHMSA proposes to establish three timeframes for remediating defects in non-HCA areas: Immediate repair conditions, 2-year repair conditions (rather than one-year for HCAs), and monitored conditions. These changes will ensure the prompt remediation of anomalous conditions on all gas pipeline segments, commensurate with risk, while allowing operators to allocate their resources to those areas that present a higher risk.

C.5. Have ILI tool capability advances resulted in a need to update the ''dent with metal loss'' repair criteria?

1. INGAA commented that ILI tool capabilities have improved to the point where it is appropriate to revise the dent-with-metal loss criterion. This comment was supported by comments received from many of its operator members. INGAA suggested that Section 851.4(f) of ASME/ANSI B31.8 provides appropriate guidance in this area.

2. AGA suggested that it would be appropriate to eliminate the immediate response criterion for ''dent with metal loss.'' This comment was supported by comments received from many of its operator members. They commented that industry experience has shown that many dents do not require immediate repair.

3. Texas Pipeline Association, Texas Oil & Gas Association, MidAmerican, Paiute, Southwest Gas, and Atmos supported revising this criterion. These commenters noted that improvements in ILI allow better distinction between a gouge and corrosion wall loss. MidAmerican further commented that there are problems with implementing § 192.933 as written.

4. Northern Natural Gas stated that it would support treating these anomalies as mechanical damage, and suggested that this would simplify the regulations.

5. Ameren Illinois suggested further study of this proposal taking into account current ILI technology.

6. Accufacts and an anonymous commenter opposed changes to this criterion. These commenters suggested that ILI is still not adequate to determine reliably the time to failure of this compound threat.

7. GPTC and Nicor suggested that PHMSA consider updating the Dent Study technical report [35] that discusses reliability and application of ILI.

Response to Question C.5 Comments

PHMSA appreciates the information provided by the commenters. PHMSA is not proposing to update the dent-with-metal-loss criterion at this time. PHMSA will continue to evaluate this criterion, including consideration of additional research to better define the repair criteria for this specific type of defect.

C.6. How do operators currently treat assessment tool uncertainties when comparing assessment results to repair criteria? Should PHMSA adopt explicit voluntary standards to account for the known accuracy of in-line inspection tools when comparing in-line inspection tool data with the repair criteria? Should PHMSA develop voluntary assessment standards or prescribe ILI assessment standards including wall loss detection threshold depth detection, probability of detection, and sizing accuracy standards that are consistent for all ILI vendors and operators? Should PHMSA prescribe methods for validation of ILI tool performance such as validation excavations, analysis of as-found versus as-predicted defect dimensions? Should PHMSA prescribe appropriate assessment methods for pipeline integrity threats?

1. INGAA, supported by many of its member companies, reported that operators use many methods to accommodate ILI uncertainties, not simply adding tool tolerance to results. INGAA suggested API–1163, In-line Inspection Systems Qualification Standard, as an appropriate guide. INGAA noted this standard is non-prescriptive; INGAA expressed its belief prescriptive standards would stifle innovation. INGAA also reported that ASME has plans to update its standard on ''Gas Transmission and Distribution Piping Systems,'' ASME/ANSI B31.8S, regarding treatment of uncertainties based on the results of Pipeline Research Council International (PRCI) research that was underway at the time comments were submitted.

2. AGA and a number of pipeline operators suggested that tool tolerances should be added to ILI results.

3. Texas Pipeline Association, Texas Oil & Gas Association, and Atmos reported their understanding that most operators follow ASME/ANSI B31.8S as a guide.

4. Northern Natural Gas and Kern River expressed their conclusion that PHMSA's Gas Integrity Management Program Frequently Asked Question FAQ–68 provides sufficient guidance on the treatment of uncertainties (FAQs can be viewed at *http://primis.phmsa.dot.gov/gasimp/faqs.htm*). They noted that technology is developing rapidly in this area, which they imply is a reason not to impose prescriptive requirements.

5. Texas Pipeline Association and Texas Oil & Gas Association agreed that prescriptive requirements should not be imposed, because the rapidly-developing technology would soon render them obsolete.

6. GPTC, Nicor, MidAmerican, and Atmos argued that prescriptive methods for validating tool performance are not an appropriate subject for regulation.

7. Ameren Illinois commented that it sees no technical justification for establishing requirements in this area.

8. Accufacts suggested that PHMSA specify minimum standards for ILI validation, including specifying a required number of digs. Alaska Department of Natural Resources and California Public Utilities Commission took a similar stance, all arguing that standards assure public confidence and consistency of results.

9. A private citizen commented that voluntary standards are not sufficient because they cannot be enforced.

10. An anonymous commenter recommended against adopting requirements for treatment of inaccuracies. The commenter opined that operators are doing better in this area, contending that smaller operators, in particular, needed time to learn. The commenter suggested that specific rules would set many operators back.

11. INGAA and many of its pipeline operators commented that incorporating standards into part 192 that compete with industry standards would be counterproductive. INGAA noted that API–1163, API–579–1, Fitness-for-Service, and ASNT ILI–PQ, In-Line Inspection Personnel Qualification and Certification Standard, are already in wide use and contended specifying standards in the regulations would stifle further development.

12. GPTC and Nicor agreed with INGAA, noting that the regulatory approval process cannot keep up with technological development.

13. Northern Natural Gas recommended that PHMSA not adopt standards for addressing ILI inaccuracies, contending the many

[35] Baker and Kiefner & Associates, ''Dent Study Technical Report,'' (November 2004, OPS TTO Number 10, available at *http://primis.phmsa.dot.gov/gasimp/techreports.htm*).

different tools currently in use would make this impractical.

14. MidAmerican reported its belief that operators have sufficient incentive to work with ILI vendors to assure appropriate validation of ILI results.

15. Paiute and Southwest Gas argued against adoption of regulatory standards to treat ILI uncertainties, noting that this subject is already addressed in ASME/ANSI B31.8S.

16. AGA, supported by a number of its member companies, suggested that PHMSA should not prescribe IM methods, noting that operators have demonstrated the ability to conduct assessments without them.

17. Accufacts, Alaska Natural Gas Development Authority, and California Public Utilities Commission argued for requirements prescribing assessment methods for various threats. These commenters suggested that such requirements would be a bridge to better risk management strategies and contended that there is currently an over-reliance on direct assessment.

Response to Question C.6 Comments

PHMSA appreciates the information provided by the commenters. The majority of comments do not support adopting explicit standards or analytical methodologies to account for the known accuracy of in-line inspection tools. PHMSA concurs that prescriptive rules to account for the accuracy of in-line inspection tools is not practical, however it is beneficial to all to clarify PHMSA's expectations with respect to current performance-based regulations in this area which specify that internal inspection may be used to identify and evaluate potential pipeline threats. Therefore, PHMSA proposes to add detailed performance-based rule language to require that operators using ILI must explicitly consider uncertainties in reported results (including tool tolerance, anomaly findings, and unity chart plots or equivalent for determining uncertainties) in identifying anomalies. While ASME/ANSI B31.8S discusses uncertainties, PHMSA believes it will improve the visibility and emphasis on this important issue to explicitly address uncertainties in the rule text.

C.7. Should PHMSA adopt standards for conducting in-line inspections using ''smart pigs,'' the qualification of persons interpreting in-line inspection data, the review of ILI results including the integration of other data sources in interpreting ILI results, and/or the quality and accuracy of in-line inspection tool performance, to gain a greater level of assurance that injurious pipeline defects are discovered? Should these standards be voluntary or adopted as requirements?

1. AGA and its pipeline operator members argued against the adoption of standards. AGA commented that voluntary use has proven to be sufficient and expressed its position that consensus standards should not be adopted into regulations until widespread experience has been gained with their use. AGA contended that premature adoption would stifle technological innovation.

2. INGAA and many of its members commented that PHMSA's process for review and adoption of standards must be streamlined if existing consensus standards are incorporated into regulations. Such improvements, INGAA contended, would assure that standard improvements are adopted without delay.

3. An anonymous commenter, GPTC, and Nicor cited similar concerns in suggesting that standards not be adopted into regulations, contending that the rulemaking process cannot keep up with technological change.

4. Texas Pipeline Association and Texas Oil & Gas Association objected to the adoption of ILI standards in regulations, contending that voluntary use is more appropriate.

5. MidAmerican commented that operator qualification requirements should be applied to ILI, as this would provide higher assurance of defect discovery. Beyond this, however, MidAmerican contended that the use of consensus standards should remain voluntary, as this allows the operator to select those standards most appropriate to its circumstances.

6. Paiute and Southwest Gas objected to the incorporation of ILI standards into regulations. The companies expressed a belief that there is no technical basis for doing so. They commented that the question, as posed in the ANPRM, implies that anomalies are not now being found and contended that there is no evidence to support this implication.

7. A private citizen, Thomas Lael, and Alaska Department of Natural Resources commented that PHMSA should require operators to meet specified standards. Mr. Lael referred to an incident that occurred following a pipeline assessment conducted in Ohio in 2011; Mr. Lael contended that the reasons the incident cause was not identified by the assessment are unknown to the public.

8. Pipeline Safety Trust commented that PHMSA should assure assessment tools are capable and are used properly.

9. The NTSB recommended that PHMSA require all pipelines to be made piggable, giving priority to older lines, citing their recommendation P–11–17.

Response to Question C.7 Comments

PHMSA appreciates the information provided by the commenters. The majority of industry comments do not support the incorporation of ILI standards into regulations. However, based on the information presented below, PHMSA has concluded that it is prudent to propose incorporating available consensus ILI standards into the regulations. The current pipeline safety regulations for integrity management of segments in HCAs contained in 49 CFR 192.921 and 192.937 require that operators assess the material condition of pipelines in certain circumstances and allow use of in-line inspection tools for these assessments. PHMSA proposes to incorporate similar requirements for non-HCA pipe segments in § 192.710. Operators are required to follow the requirements of ASME/ANSI B31.8S in selecting the appropriate ILI tools. However, ASME B31.8S provides only limited guidance for conducting ILI assessments. At the time the integrity management rules were promulgated, there was no consensus industry standard that addressed performance of ILI. Three related standards have since been published: API STD 1163–2005, NACE SP0102–2010, and ANSI/ASNT ILI–PQ–2010. API–1163 serves as an umbrella document to be used with and complement the NACE and ASNT standards. These three standards have enabled service providers and pipeline operators to provide processes that will qualify the equipment, people, processes, and software utilized in the in-line inspection industry. The incorporation of these standards into pipeline safety regulations developed through best practices of the industry based on the experience of numerous operators will promote high quality and more consistent assessment practices. Therefore, PHMSA is proposing to incorporate these industry standards into the regulations to provide clearer guidance for conducting integrity assessments with in-line inspection. PHMSA will continue to evaluate the need for additional guidance for conducting integrity assessments.

C.8. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements*

pursuant to the commenter's suggestions.

- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

D. Improving the Collection, Validation, and Integration of Pipeline Data

The ANPRM requested comments regarding whether more prescriptive requirements for collecting, validating, integrating and reporting pipeline data are necessary. The current IM regulations require that gas transmission pipeline operators gather and integrate existing data and information concerning their entire pipeline that could be relevant to pipeline segments in HCAs (§ 192.917(b)). Operators are then required to use this information in a risk assessment of the HCA segments (§ 192.917(c)) that must subsequently be used to determine whether additional preventive and mitigative measures are needed (§ 192.935) and to define the intervals at which IM reassessments must be performed (§ 192.939). Operators' risk analyses and conclusions can only be as good as the information used to perform the analyses. On August 30, 2011, after the ANPRM was issued, the NTSB adopted its report on the gas pipeline accident that occurred on September 9, 2010, in San Bruno, California. Results from the NTSB investigation indicate that the pipeline operator's records regarding the physical attributes of the pipe segments involved in the incident were erroneous. NTSB recommendation P–11–19 recommended that PHMSA require IM programs be assessed to assure that they are based on clear and meaningful metrics. In addition, Section 23 of the Act requires verification to ensure that records accurately reflect the physical and operational characteristics of pipelines. PHMSA issued an Advisory Bulletin (76 FR 1504; January 10, 2011) on this issue. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic D

1. INGAA reported that it is presently working on data integration guidelines. INGAA cautioned that requirements in this area can be very costly, since they often necessitate redesign of existing data management systems.

2. AGA commented that no records requirements would have prevented the San Bruno accident, and stated that verifying records does not assure completeness, as unknown parameters remain unknown.

3. A private citizen suggested that PHMSA should require operators to identify segments where they lack knowledge of critical parameters. The commenter suggested that this could facilitate emergency communications and help prioritize pipe replacement programs.

Response to General Comments for Topic D

PHMSA appreciates the information provided by the commenters. PHMSA is proposing to clarify requirements for collecting, validating, and integrating data. The current rule invokes ASME/ANSI B31.8S requirements for data collection and integration. To provide greater visibility and emphasis on this important aspect of integrity management, PHMSA is proposing to place these requirements in the rule text, rather than incorporating ASME/ANSI B31.8S by reference. The proposed requirements clarify PHMSA's expectations regarding the minimum list of data an operator must collect, and also includes performance-based language that requires the operator to validate data it will use to make integrity-related decisions, and require operators to integrate all such data in a way that improves the analysis. The proposed rule would also require operators to use reliable, objective data to the maximum extent practical. To the degree that subjective data from subject matter experts must be used, PHMSA proposes to require that an operator's program include specific integrity assessment and findings data for the threat features to compensate for subject matter expert (SME) bias. The importance of these aspects of integrity management was emphasized by both the NTSB (Recommendation P–11–19) and Congress (The Act, Section 11(a)(4)).

Comments Submitted for Questions in Topic D

D.1. What practices are now used to acquire, integrate and validate data (e.g., review of mill inspection reports, hydrostatic tests reports, pipe leaks and rupture reports) concerning pipelines? Are practices in place, such as excavations of the pipeline, to validate data?

1. INGAA reported that its members have completed a concerted effort to validate pipeline historical records pursuant to PHMSA Advisory Bulletin 11–01 (issued January 10, 2011).

2. Texas Pipeline Association and Texas Oil & Gas Association commented that there is no great benefit to be gained from adding a verification requirement for historical data to the regulations. The associations believe that most operators will correct their records when they become aware of errors regardless of how the erroneous information is discovered. The associations suggested that there could be value in validating databases against original records, since an underlying problem of the San Bruno accident was errors in transferring original records into a database.

3. Ameren Illinois reported that it collects data on exposed pipe in accordance with §§ 192.459 and 192.475.

4. Northern Natural Gas and Kern River reported that their primary integration tool is integrity alignment sheets, which show the class location, profile, aerial photography, alignment and structure data, in-line inspection results, other integrity data, *i.e.,* close-interval survey or pressure test results and pipe, coating and appurtenance data. Data is validated as opportunities arise.

5. Paiute and Southwest Gas reported that they confirm the location and properties of its pipeline as opportunities arise; more data are collected as assessments are conducted.

6. California Public Utilities Commission suggested that operators be explicitly required to obtain all historical records and that there be an officer statement that a thorough search for all records has been conducted.

7. A private citizen commented on the lack of some historical data, implying that operators should be required to validate their knowledge of older pipelines.

8. An anonymous commenter stated that older data is typically not validated.

9. INGAA and AGA reported that pipeline operators take advantage of exposed pipe to collect and validate data on in-service pipelines. This includes excavations for ILI validation, those conducted as part of direct assessment, and removed or replaced pipelines. A number of pipeline operators provided comments supporting the comments of each association.

10. GPTC and Nicor suggested that excavations not be required for the sole purpose of validating data, contending that the risks posed by such a requirement would outweigh any benefit obtained.

11. MidAmerican reported that it validates information when pipeline is excavated and through its routine practices.

Response to Question D.1 Comments

PHMSA appreciates the information provided by the commenters. See response to question D.4.

D.2. Do operators typically collect data when the pipeline is exposed for maintenance or other reasons to validate information in their records? If discrepancies are found, are investigations conducted to determine the extent of record errors? Should these actions be required, especially for HCA segments?

1. AGA, Paiute, and Southwest Gas reported that operators use exposed pipe as an opportunity to collect information. AGA further suggested, however, that PHMSA should not draft a rule governing these practices. AGA contended the circumstances of pipe exposures vary too much to be addressed by a regulatory requirement. AGA expressed its conclusion that the requirements in § 192.605(b)(3) provide adequate guidance and that section 23 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 provides additional guidance. AGA noted that operators investigate identified inaccuracies and errors. A number of other pipeline operators provided comments supporting AGA's comments.

2. Texas Pipeline Association, Texas Oil & Gas Association, Atmos, MidAmerican, and Ameren Illinois reported that operators typically collect information on pipe type and condition, but not on historical information and pipe specifications. They commented that collecting this information would require additional testing and pose operational impacts.

3. Iowa Utilities Board and Iowa Association of Municipal Utilities commented that any new requirement should be limited to collecting readily obtainable data, principally that which can be determined visually. They suggested that the data elements in ANPRM questions D.1 and D.3 go beyond what can readily be observed or obtained and it would be impractical to require this data to be collected during pipe exposures.

4. California Public Utilities Commission commented that any new requirements to collect data during pipe exposures should address all instances of exposure rather than be limited to HCAs, noting that non-HCA segments can become HCA segments due to changes in land use near the pipeline.

5. Thomas Lael and Alaska Department of Natural Resources commented that operators should be required to collect specific data during pipe exposures. These commenters contended that not all operators currently collect available data during pipe exposures.

6. MidAmerican, Paiute, and Southwest Gas commented that no new requirements are needed because the requirements in part 192 and guidance in ASME/ANSI B31.8S are sufficient.

7. An anonymous commenter suggested that operators be required to collect data if they do not have enough information to analyze the risks of the pipeline segment.

Response to Question D.2 Comments

PHMSA appreciates the information provided by the commenters. The expanded rule language does not impose new requirements for collecting specific data during pipe exposures, but the response to question D.4 discusses proposed changes to collection and validation practices to improve data integration and risk assessment practices.

D.3. Do operators try to verify data on pipe, pipe seam type, pipe mechanical and chemical properties, mill inspection reports, hydrostatic tests reports, coating type and condition, pipe leaks and ruptures, and operations and maintenance (O&M) records on a periodic basis? Are practices in place to validate data, such as excavation and in situ examinations of the pipeline? If so, what are these practices?

1. AGA, GPTC, Nicor, Paiute, and Southwest Gas reported that operators do try to verify information but that operator practices are too numerous to list in response to this general question. They contended that the requirements for external corrosion control in § 192.459 and for internal corrosion control in § 192.475 and the guidance in Advisory Bulletin 11–01 are sufficient and no new requirements are needed. A number of other pipeline operators provided comments supporting AGA's comments.

2. INGAA, supported by many of its pipeline operator members, commented that there are limited, if any, methods to determine accurately mechanical properties of pipe that is *in situ.* INGAA's comments listed a number of methods that can be used to obtain approximate values for some pipe characteristics, such as steel hardness and yield strength.

3. Texas Pipeline Association and Texas Oil & Gas Association commented that operators do not validate mill data after initial construction.

4. Ameren Illinois reported that data review and correction is a normal part of the business of pipeline operation. Ameren commented that additional work in this area is likely to result from Advisory Bulletin 11–01.

5. Northern Natural Gas reported that data correction occurs when a discrepancy is identified. Northern also noted that it has added data to its risk model over time, principally related to determination of the potential consequences of a pipeline accident.

6. MidAmerican commented that operators validate pipeline information periodically.

7. California Public Utilities Commission reported that California pipeline operators have begun validating pipeline data since the San Bruno accident. CPUC commented that operators should determine pipeline specifications for all exposed facilities and use them to validate their records.

8. Paiute and Southwest Gas reported that it is their practice to obtain pipeline data before an integrity management excavation and then to validate that information in the field.

9. MidAmerican reported that it uses a geospatial database as its principal tool for collecting and validating pipeline information.

10. An anonymous commenter suggested that pipeline operators do not routinely collect information to validate their databases during pipeline excavations.

Response to Question D.3 Comments

PHMSA appreciates the information provided by the commenters. See response to question D.4.

D.4. Should PHMSA make current requirements more prescriptive so operators will strengthen their collection and validation practices necessary to implement significantly improved data integration and risk assessment practices?

1. INGAA, GPTC, Nicor, Ameren Illinois, MidAmerican, Paiute and Southwest Gas commented that additional prescriptive requirements are not needed. These commenters suggested that Advisory Bulletin ADB–11–01, subpart O of part 192, and ASME/ANSI B31.8S are sufficient to govern these practices. INGAA added requirements for data validation during excavations could introduce workplace hazards that would outweigh any benefit to be gained. In the event PHMSA proceeds to propose new requirements, INGAA requested they be limited to a reasonable process and allow assumptions to be made to fill information gaps, suggesting this would be a more cost-effective approach than

rigorous requirements to collect and validate all information. A number of other pipeline operators provided comments supporting INGAA's comments.

2. AGA, supported by a number of its pipeline operator members, commented that there is no evidence to support a need for more prescriptive requirements leading to better data collection or validation and, therefore, no such requirements are needed.

3. Pipeline Safety Trust, NAPSR, California Public Utilities Commission, and Commissioners of Wyoming County, Pennsylvania, commented that requirements for data collection, validation, and use should be more prescriptive. These commenters noted that the investigation of the San Bruno accident identified at least one pipeline operator was not doing an adequate job of data validation. They noted that NTSB recommendations P–11–18 and P–11–19 apply to this topic. NAPSR specifically requested that new requirements specify precise inspection criteria.

4. Texas Pipeline Association and Texas Oil & Gas Association suggested that there is no value in periodic validation of pipeline data and new requirements are not needed in this area. Northern Natural Gas agreed, noting that pipeline data does not change over time, and relevant data that is subject to change, is that data needed to evaluate the consequences of potential pipeline accidents.

5. Accufacts commented that more specific criteria, including minimum data requirements, are needed for record retention. Accufacts noted that integrity management is data-based and that too many operators claim that data is lost or cannot be found.

6. Alaska Department of Natural Resources suggested that data integration should be required in interpreting ILI results.

7. An anonymous commenter suggested that specific requirements are not needed in this area, contending that most data has been validated through normal operator practices.

8. A private citizen suggested that PHMSA require pipeline operators to post all records for access by state and local government officials, PHMSA, and the media. The commenter suggested such a ''sunshine'' provision would improve recordkeeping, even if no one ever examines the posted records.

Response to Question D.4 Comments

PHMSA appreciates the information provided by the commenters in response to questions D.1 through D.4. Commenters disagreed on the need and benefit of making current requirements more prescriptive so operators will strengthen their collection and validation practices. PHMSA believes enhancing regulations in this area is an important element of good integrity management practices. On July 21, 2011, in response to the San Bruno incident, PHMSA sponsored a public workshop on risk assessment and related data analysis and recordkeeping issues to seek input from stakeholders. Based in part on the input received at this workshop, and the information submitted in response to the ANPRM, PHMSA proposes to clarify the performance-based requirements for collecting, validating, and integrating pipeline data by adding specificity to the data integration language, establishing a number of pipeline attributes that must be included in these analyses, explicitly requiring that operators integrate analyzed information, and ensuring data is reliable. The rule also requires operators to use validated, objective data to the maximum extent practical. PHMSA also understands that objective sources such as as—built drawings, alignment sheets, material specifications, and design, construction, inspection, testing, maintenance, manufacturer, or other related documents are not always available or obtainable. To the degree that subjective data from subject matter experts must be used, PHMSA proposes to require that an operator's program include specific features to compensate for subject matter expert bias. PHMSA believes that these proposed changes would not impose new requirements or more prescriptive requirements, but clarifies the intent of the regulation. However, PHMSA requests public comment on whether and the extent to which this proposal may change behavior.

D.5. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

E. Making Requirements Related to the Nature and Application of Risk Models More Prescriptive

The ANPRM requested comments regarding whether requirements related to the nature and application of risk models should be made more prescriptive to improve the usefulness of these analyses in controlling risks from pipelines. Current regulations require that gas transmission pipeline operators perform risk analyses of their pipelines and use these analyses to make certain decisions to assure the integrity of their pipeline and to enhance protection against the consequences of potential incidents. The regulations do not prescribe the type of risk analysis nor do they impose any requirements regarding its breadth and scope, other than requiring that it consider the entire pipeline. PHMSA's experience in inspecting operator compliance with IM requirements has identified that most pipeline operators use a relative index-model approach to performing their risk assessments and that there is a wide range in scope and quality of the resulting analyses. It is not clear that all of the observed risk analyses can support robust decision-making and management of the pipeline risk. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic E

1. INGAA and Chevron commented that continuing the performance-based regulatory approach, exemplified by integrity management, is critically important to pipeline safety. They suggested that prescriptive management systems are task oriented, do not adjust easily to new information or knowledge, inhibit innovation, and could thwart safety improvements. A number of other pipeline operators provided comments supporting INGAA's comments.

2. Accufacts commented that risk management approaches permitted in IM need additional prescriptive measures to clarify strengths and weaknesses and to assure compliance. Public perception resulting from the number of serious incidents is that current risk analysis and risk management approaches are not sufficient. The impression is that risk management is being used to justify unwise lowest cost decisions rather than being used as a tool to avoid failure. Accufacts further suggested that interactive threats need to be addressed by prescriptive requirements in safety

regulations because operators may be under the illusion that some of the more serious threats are stable after almost 10 years of IM regulation.

3. Oleksa and Associates suggested that it would be statistically more valid for many (perhaps most) operators for PHMSA to perform continual evaluation and assessment using established performance measures along with data submitted by operators on annual, incident, and safety-related condition reports, and then to promulgate more prescriptive regulations resulting from that assessment. Oleksa suggested that it may be time to re-evaluate the overall concept of integrity management to determine whether it makes sense for each operator to make assessments that might be more valid if made on a national level. Oleksa also stated that there should be a concerted effort in promulgating any new regulations towards making the regulations simple enough so that they can be understood relatively easily.

4. TransCanada commented that PHMSA's IM regulations should provide explicit metrics for operators to demonstrate safety decision processes without restricting the opportunity to use more accurate and advanced methods. TransCanada said that any efforts to make risk models more prescriptive should focus on process elements while providing operators the flexibility to build processes which recognize the unique characteristics of their pipeline systems. The company also opined that issuing more detailed guidelines on specific integrity management plan elements would enhance the current, performance-based approach and generate additional benefits that the public and operators desire.

5. Dominion East Ohio Gas opposed making requirements for risk models more prescriptive. Like INGAA, they that noted prescriptive management systems are task oriented and do not adjust easily to new information or knowledge. They inhibit innovation and could thwart safety improvements.

6. NAPSR strongly urged PHMSA to make the nature and application of risk models more prescriptive. NAPSR commented that PHMSA has not provided any data that supports the theory that risk modeling provides a stronger safety environment and contended that, in fact, the opposite may be occurring.

7. A private citizen suggested that PHMSA correlate the quality of an operator's risk model with the number of enforcement actions against that operator.

8. A private citizen suggested that risk analysis requirements should remain flexible, commenting that prescribed methods or requirements could mask operator-specific issues.

Response to General Comments for Topic E

PHMSA appreciates the information provided by the commenters. PHMSA agrees that prescriptive rules for risk assessments are not appropriate because one-size-fits-all regulations would not be effective for such a diverse industry. However, PHMSA does believe that operator risk models and risk assessments should have substantially improved since the initial framework programs established nearly 10 years ago. While simple index or relative (qualitative) ranking models were useful to prioritize HCA segments for purposes of scheduling integrity baseline assessments, those models have limited utility to perform the analyses needed to better understand pipeline risks, better understand failure mechanisms (especially for interacting threats), or to identify effective preventive and mitigative measures. PHMSA is proposing to further clarify its expectations for this aspect of the performance-based regulations to further improve pipeline safety. On July 21, 2011, PHMSA sponsored a public workshop on risk assessment to seek input from stakeholders. PHMSA has evaluated the input it received at this workshop. PHMSA proposes to clarify the risk assessment aspects of the IM rule to explicitly articulate functional requirements and to assure that risk assessments are adequate to: (1) Evaluate the effects of interacting threats, (2) determine intervals for continual integrity reassessments, (3) determine additional preventive and mitigative measures needed, (4) analyze how a potential failure could affect HCAs, including the consequences of the entire worst-case incident scenario from initial failure to incident termination, (5) identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location, (6) account and compensate for uncertainties in the model and the data used in the risk assessment, and (7) evaluate predicted risk reduction associated with preventive and mitigative measures. In addition, in response to NTSB recommendation P–11–18, PHMSA proposes to require that operators validate their risk models in light of incident, leak, and failure history and other historical information. PHMSA also proposes to expand the list of example preventive and mitigative measures to include the following items: establish and implement adequate operations and maintenance processes that could affect safety; establish and deploy adequate resources for successful execution of activities, processes, and systems associated with operations, maintenance, preventive measures, mitigative measures, and managing pipeline integrity; and correct the root cause of past incidents to prevent recurrence.

In response to Oleksa's comments, PHMSA is addressing performance measures outside of this rulemaking. Performance measures will be addressed separately in response to NTSB safety recommendations P–11–18 and P–11–19.

Comments Submitted for Questions in Topic E

E.1. Should PHMSA either strengthen requirements on the functions risk models must perform or mandate use of a particular risk model for pipeline risk analyses? If so, how and which model?

1. INGAA, AGA, and many pipeline operators reported that they do not believe there is a pipeline safety benefit for PHMSA to ''strengthen'' or revise the requirements on functions that risk models must perform or in mandating the use of specific risk models. These commenters noted that there is a tremendous amount of diversity in the pipeline systems of individual operators and operators must have the flexibility to select the risk model that best supports their systems.

2. GPTC commented that there is no 'one-size-fits-all' risk model. GPTC further commented PHMSA has offered no data supporting the need to strengthen requirements or mandate a particular risk model.

3. Kern River noted that differences exist between pipeline operators on how much detail is needed in their risk assessment models. The specific factors and required risk model complexity will differ for each pipeline company based on its active threats, the preventive and mitigative measures employed, its data acquisition methods and the amount of required data.

4. MidAmerican commented that no change is needed to requirements concerning risk models. MidAmerican noted that ASME/ANSI B31.8S provides extremely detailed requirements in this area, and suggested that operators should have the freedom to choose the risk model best suited to their operation. Northern Natural Gas agreed, noting that there are large differences within the industry on the complexity of the risk assessment models used based on the

pipeline age and configuration, threats, and data available.

5. Paiute and Southwest Gas opposed more restrictive requirements for risk modeling. They noted that operators have a decade of experience working with IM and therefore, should have the flexibility to choose the risk model that best suits their system.

6. Accufacts commented that this is an area that needs more prescriptive requirements. Accufacts questioned whether the current approach of reliance on risk modeling is even appropriate. They stated that there appears to be a disconnect between the use of risk models and risk analysis with pipeline operation and the ability of regulators to apply and enforce the approach.

7. TransCanada noted that mandating the use of a specific risk model may result in a more uniform approach across the industry, but may also force operators to abandon their existing risk models, including the improvements made to them based on 10 years of integrity management experience. This would not appear to advance risk modeling and might even be counterproductive.

8. WKM Consultancy commented that mandating a specific risk assessment model would not be a beneficial addition to regulations. Such a mandate would stifle creativity and require extensive definitions and documentation of that methodology. A mandated model would introduce a prescriptive element with substantial ''overhead'' related to the maintenance of the model's documentation by the regulators. They suggested that a better solution would be to develop guidelines of essential ingredients necessary in any pipeline risk assessment.

9. An anonymous commenter opposed requiring the use of a specific risk model, suggesting that operators should use models with which they are comfortable. The commenter did suggest that PHMSA strengthen requirements concerning the use of risk models for purposes other than risk-ranking segments, expressing a belief that most operators are using their models only for that purpose.

10. California Public Utilities Commission recommended that PHMSA require statistical data be maintained and used to support the weightings assigned by risk models to various threats.

Response to Question E.1 Comments

PHMSA appreciates the information provided by the commenters. A large number of comments do not support adding a requirement for a specific risk assessment model or for strengthening or revising the required functions that risk models must perform. PHMSA agrees that prescribing the use of particular risk assessment models is not appropriate for such a diverse industry, and notes that relative index models have been successfully used to rank pipelines to prioritize baseline assessments. However, PHMSA believes that the integrity management rule anticipates that operators would continually improve their risk assessment processes and that there are specific risk assessment attributes related to the nature and application of risk models that need clarification. Such attributes and shortcomings were discussed at the ''Improving Pipeline Risk Assessments and Recordkeeping'' workshop with stakeholders, held on July 21, 2011.

PHMSA proposes to articulate clear functional requirements, in performance-based terms, for risk assessment methods used by operators. While PHMSA does not propose to prescribe the specific risk assessment model operators must use, PHMSA does propose to clarify the characteristics of a mature risk assessment program. These include: (1) Identifying risk drivers; (2) evaluating interactive threats; (3) assuring the use of traceable and verifiable information and data; (4) accounting for uncertainties in the risk model and the data used; (5) incorporating a root cause analysis of past incidents; (6) validating the risk model in light of incident, leak and failure history and other historical information; (7) using the risk assessment to establish criteria for acceptable risk levels; and (8) determining what additional preventive and mitigative measures are needed to achieve risk reduction goals. PHMSA proposes to clarify that the risk assessment method selected by the operator must be capable of successfully performing these functions.

E.2. It is PHMSA's understanding that existing risk models used by pipeline operators generally evaluate the relative risk of different segments of the operator's pipeline. PHMSA is seeking comment on whether or not that is an accurate understanding. Are relative index models sufficiently robust to support the decisions now required by the regulation (e.g., evaluation of candidate preventive and mitigative measures, and evaluation of interacting threats)?

1. Industry commenters, including INGAA, AGA, Texas Pipeline Association, Texas Oil & Gas Association, WKM Consultancy, and many pipeline operators reported that PHMSA's understanding is correct and that risk models in use generally *evaluate the relative risk of different segments of the operator's pipeline.* AGA noted that operators have selected and implemented the risk models that allowed them to prioritize the covered segments for the baseline assessment and subsequent reassessments and that this complied with the Pipeline Safety Improvement Act of 2002.

2. AGA, supported by a number of its pipeline operator members, commented that risk models currently in use are sufficiently robust. Ameren Illinois and GPTC expressed a similar belief.

3. INGAA, supported by some of its members, noted that there is room for improvement in the current practices of risk modeling. INGAA reported that the industry has established committees to identify advancements in risk modeling.

4. WKM Consultancy commented that the more robust of the relative risk index techniques are often capable of fulfilling some aspects of IM risk management requirements such as prioritization, but that other aspects of the risk management requirements are not well supported by relative risk assessments. They suggested that some risk assessment models in current use could benefit from application of more robust and modern techniques.

5. Kern River commented that a relative risk model is sufficiently robust to support decisions on preventive and mitigative measures and assessment intervals.

6. MidAmerican reported that its risk model complies with ASME/ANSI B31.8S and is sufficiently robust to support decisions that are not specifically related to assessments. MidAmerican further stated that its risk model produces results consistent with its subject matter expert assessments of relative risk.

7. Paiute and Southwest Gas reported their conclusion that their risk models are robust and support the process of evaluation and selection of preventive and mitigative measures.

8. Texas Pipeline Association and Texas Oil & Gas Association noted that all sources of information relative to the integrity of a transmission pipeline segment and the identified risk should be used in the selection of preventive and mitigative measures. Atmos agreed, noting that preventive and mitigative measures for a given pipeline segment are based on the identified threats.

9. A private citizen suggested that consideration of system-wide high risk (*e.g.,* urban areas) should be required, contending relative risk is not good enough when an entire system poses high risks.

Response to Question E.2 Comments

PHMSA appreciates the information provided by the commenters. Although a large number of comments contend risk models currently in use are sufficiently robust, PHMSA believes that there are specific risk assessment attributes not found in many of the simple index or relative risk models currently in use. The July 21, 2011, workshop on ''Improving Pipeline Risk Assessments and Recordkeeping'' identified several shortcomings in risk assessments conducted using qualitative, index, or relative risk methodologies, and PHMSA is proposing to clarify requirements to address these issues including the need for better or more prescriptive guidance to address data gaps, data integration, uncertainty, interacting threats, risk management, and quantitative approaches instead of subjective or qualitative approaches. The proposed regulation would require operators to conduct risk assessments that effectively analyze the identified threats and potential consequences of an incident for each HCA segment. Additionally, the proposed regulation would require the risk assessment to include evaluation of the effects of interacting threats, including those threats and anomalous conditions not previously evaluated. It should be further noted that the intent of the original IM rule is that any risk assessment would consider system-wide risk.

E.3. How, if at all, are existing models used to inform executive management of existing risks?

1. INGAA commented that operators should develop internal communication plans and they should follow Section 10.3 of ASME/ANSI B31.8S in doing so. AGA similarly noted that the methods used to disseminate results of the risk evaluation to executive management are operator specific and detailed in the operator's integrity management plan. A number of pipeline operators provided comments supporting both INGAA's and AGA's comments.

2. Texas Pipeline Association and Texas Oil & Gas Association noted that the results of risk modeling are usually used in conjunction with assessment results to inform executive management of actions required beyond normal repair, additional preventive and mitigative measures, discussion of high risk pipelines, and progress in meeting assessment goals.

3. WKM Consultancy commented that operators are obliged to communicate all aspects of integrity management to higher level managers at regular intervals. They noted that all prudent operators are very interested in risk management and results of risk modeling are usually a centerpiece of discussion and decision-making.

4. Ameren Illinois reported that its IM plan provides for informing executive management of existing risks.

5. Atmos reported that it provides executive management with periodic updates on the status of its integrity management program. During these updates, Atmos' executive management reviews baseline assessment plans, assessment results, anomalies discovered and mitigated, anomalies discovered and scheduled for repair, leading causes of anomalies, and preventive and mitigative actions taken.

6. Kern River noted that it provides its executive management with reports describing integrity management program activities and results and that the company engages the use of the risk model as an input to financial planning and maintenance planning. MidAmerican also reported that risk scores are used to support capital, operating and maintenance expenditures to executive management.

7. Northern Natural Gas reported that it provides executive management with reports describing integrity management program activities and results. Its executive management is engaged in the process and the use of the risk model to prioritize projects.

8. Paiute and Southwest Gas reported that integrity management activities are discussed with executive management quarterly.

9. An anonymous commenter suggested that operators generally do not use risk models to inform executives, because they would have to explain the models in order to do so.

Response to Question E.3 Comments

PHMSA appreciates the information provided by the commenters. PHMSA understands that internal company processes for communication with executive management are specific to each company. To strengthen the application of risk assessment, PHMSA is proposing to clarify requirements by providing more specific and detailed examples of the kinds of preventive and mitigative measures operators should consider. The proposed rulemaking would include the following specific examples of preventive and mitigative measures that operators should consider: Establish and implement adequate operations and maintenance processes; establish and deploy adequate resources for successful execution of activities, processes, and systems associated with operations, maintenance, preventive measures, mitigative measures, and managing pipeline integrity; and correct the root cause of past incidents to prevent recurrence. The last item necessarily requires a robust root cause analysis that identifies underlying programmatic or policy issues that create or facilitate conditions or circumstances that ultimately lead to pipeline failures.

E.4. Can existing risk models be used to understand major contributors to segment risk and support decisions regarding how to manage these contributors? If so, how?

1. INGAA and many of its pipeline operator members commented that existing models can and do provide an understanding of segment risk through threat identification, performing ''what if'' analyses, and identifying preventive and mitigative measures that will reduce risk.

2. AGA and GPTC noted that existing models selected by operators are sufficiently robust to allow the integration of large volumes of data and information to achieve a comprehensive overall risk evaluation for their systems. These risk models allow an operator to understand the specific threats associated with each pipeline segment and the preventive and mitigative measures that would be most appropriate. A number of pipeline operators provided comments supporting AGA's comments.

3. WKM Consultancy opined that currently used risk assessment models generally can significantly improve the ability to manage risks. They noted that a formal risk assessment provides the structure to increase understanding, reduce subjectivity, and ensure that important considerations are not overlooked.

4. Atmos reported that its model can be used to generate a report listing the significant variables contributing to a relatively higher risk factor score, and that if a contributing variable can be controlled, the risk model can support further actions to control the variable.

5. Ameren Illinois reported that it uses a robust risk model that can integrate various risk factors in order to evaluate its system.

6. Kern River and Northern Natural Gas commented that existing risk models can be used to understand major contributors to segment risk and support decisions regarding how to manage these contributors. By identifying threat drivers in the risk results and analyzing the data used by the model, integrity management personnel are able to reduce risk through preventive and mitigative measures, improvements in data quality, and shorter reassessment intervals.

7. MidAmerican reported that its risk model is used to understand major contributors to risk and to support decisions regarding how to manage those contributors.

8. Paiute and Southwest Gas reported that they conduct a review of threat-specific indices to identify the major contributors to risk for each threat.

9. Texas Pipeline Association and Texas Oil & Gas Association noted that risk modeling can be used to generate reports listing the significant variables contributing to high risk scores.

10. An anonymous commenter noted that risk models can serve these functions and some operators use them in this way. The commenter opined that most operators ''aren't there yet,'' and that operators who use models for this purpose have more enthusiasm for integrity management and more executive management support.

Response to Question E.4 Comments

PHMSA appreciates the information provided by the commenters. The majority of the comments suggest that current risk models provide an adequate understanding of major contributors to risk. PHMSA believes it is prudent to clarify the required attributes of risk assessment in this area and proposes to include performance-based language to assure that risk assessments adequately identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location.

E.5. How can risk models currently used by pipeline operators be improved to assure usefulness for these purposes?

1. INGAA noted that continuous improvement is required, and that industry is working on improvements to ASME/ANSI B31.8S. AGA similarly noted that risk models are periodically improved by operators by integrating new data and the results of integrity assessments. A number of pipeline operators provided comments supporting INGAA's and AGA's comments.

2. GPTC commented that new data and information are received on an ongoing basis. This new data, and results of integrity assessments, are reviewed, integrated, and added to risk models periodically.

3. WKM Consultancy suggested that a limited amount of standardization would be appropriate. They opined that this would ensure that all risk assessments contain, at a minimum, a short list of essential ingredients. For example, all assessments should produce a profile showing changes in risk along a pipeline route.

4. Ameren Illinois reported that its risk model allows for integration of information for continuous improvement.

5. Atmos commented that there is the potential for the risk model process to handle unknown data in a more useful manner. Atmos suggested that a higher risk score with ''known'' data attributes should be considered more relevant for decisions on preventive and mitigative measures than a similar score derived from ''unknown'' data attributes.

6. Kern River suggested that industry-wide research into failure probabilities and effectiveness of preventive and mitigative measures would facilitate more rigorous quantitative models. Kern River noted that vendors are continuously improving risk models.

7. MidAmerican suggested that risk models could be improved with better tracking, recording, and retrieval of assessment results. With feedback and information sharing, refining coefficients within the model will produce more accurate risk results.

8. Northern Natural Gas reported that its risk assessment process is improved every year and that its risk model vendor is heavily involved with the company in understanding how the risk results are used.

9. Paiute and Southwest Gas suggested that risk models will be improved as additional information is gained through an assessment cycle and that this continuous improvement process will then repeat through subsequent assessment cycles.

10. Texas Pipeline Association and Texas Oil & Gas Association observed that there is no 'one size fits all' solution to this issue.

Response to Question E.5 Comments

PHMSA appreciates the information provided by the commenters. The comments speak in general terms about incremental improvement of existing index-type or qualitative relative risk models. PHMSA believes that such models, while appropriate and useful for limited purposes such as ranking segments to prioritize baseline assessments, fall far short of the type of model needed to fully execute a mature integrity management program. PHMSA proposes to clearly articulate the requirements for validation of the risk assessment and proposes to clarify that an operator must ensure validity of the methods used to conduct the risk assessment in light of incident, leak, and failure history and other historical information. Additionally, the proposed rule would require that validation must: (1) Ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents as determined by root cause analysis or other means; and (2) include analysis of the factors used to characterize both the probability of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity.

E.6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

F. Strengthening Requirements for Applying Knowledge Gained Through the IM Program

The ANPRM requested comments regarding strengthening requirements related to operators' use of insights gained from implementation of an IM program. IM assessments provide information about the condition of the pipeline. Identified anomalies that exceed criteria in § 192.933 must be remediated immediately (§ 192.933(d)(1)) or within one year (§ 192.933(d)(2)) or must be monitored on future assessments (§ 192.933(d)(3)). Operators are also expected to apply knowledge gained through these assessments to assure the integrity of their entire pipeline as part of its threat identification and risk analysis process in accordance with § 192.917.

Section 192.917(e)(5) explicitly requires that operators must evaluate other portions of their pipeline if an assessment identifies corrosion requiring repair under the criteria of § 192.933. The operator must ''evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics.''

Section 192.917 also requires that operators conduct risk assessments that follow American Society of Mechanical Engineers/American National Standards Institute (ASME/ANSI) B31.8S, Section

5, and use these analyses to prioritize segments for assessment, and to determine what preventive and mitigative measures are needed for segments in HCAs. Section 5.4 of ASME/ANSI B31.8S states that ''risk assessment methods should be used in conjunction with knowledgeable, experienced personnel . . . that regularly review the data input, assumptions, and results of the risk assessments.'' That section further states, ''an integral part of the risk assessment process is the incorporation of additional data elements or changes to facility data,'' and requires that operators ''incorporate the risk assessment process into existing field reporting, engineering, and facility mapping processes'' to facilitate such updates. Neither part 192 nor ASME/ANSI B31.8S specifies a frequency at which pipeline risk analyses must be reviewed and updated; instead, this is considered to be a continuous, ongoing process. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comment for Topic F

1. MidAmerican suggested that application of knowledge gained through integrity management should not be treated any differently than any other information gained from work on or surveillance of the pipeline. MidAmerican considers this to be adequately addressed by § 192.613.

Response

PHMSA continues to believe that there are many important integrity management requirements related to insights gained from implementation of the IM program beyond those covered by the continuing surveillance requirements of § 192.613. Integrity management assessments provide information about the condition of the pipeline and operators are expected to apply the knowledge gained through these assessments to assure the integrity of their entire pipeline. PHMSA believes that the knowledge gained through IM assessments should be integrated into the risk assessment process, which is not required by § 192.613.

Comments Submitted for Questions in Topic F

F.1. What practices do operators use to comply with § 192.917(e)(5)?

1. INGAA and a number of pipeline operators noted that operators use available information and field knowledge to comply with this requirement.

2. AGA, supported by a number of its member companies, reported that operator practices are too distinct and varied to list. AGA stated that § 192.917(e)(5) is prescriptive enough and no new requirements are needed.

3. GPTC and Nicor cited NACE SP0169 and NACE RP0177 as examples of standards that can be used to guide compliance with § 192.917(e)(5).

4. Texas Pipeline Association and Texas Oil & Gas Association commented that operators use cathodic protection surveys and/or spot checks to determine whether failure is likely.

5. Northern Natural Gas reported that it takes the actions specified in § 192.917(e)(5) and includes consideration of incidents and safety related conditions.

6. Kern River, Paiute, and Southwest Gas stated that they use root cause evaluations of incidents to comply with § 192.917(e)(5).

Response to Question F.1 Comments

PHMSA appreciates the information provided by the commenters. The comments provide little information related to specific operator practices for compliance with § 192.917(e)(5). PHMSA is not proposing to amend § 192.917(e)(5) at this time; however, PHMSA proposes to clarify requirements in § 192.917(b) to ensure that the data gathering and integration process includes an analysis of both the HCA segments and similar non-HCA segments and integrates information about pipeline attributes and other relevant information, including data gathered through integrity assessments.

F.2. How many times has a review of other portions of a pipeline in accordance with § 192.917(e)(5) resulted in investigation and/or repair of pipeline segments other than the location on which corrosion requiring repair was initially identified?

1. Based on a limited response by their members to a survey, Texas Pipeline Association and Texas Oil & Gas Association reported that repair of corrosion beyond the initially-identified anomaly is rare.

2. Ameren Illinois reported that it has experienced two instances in which it repaired other segments after identifying corrosion on a covered pipeline segment.

3. MidAmerican reported that it has experienced a few instances of corrosion where coating was damaged during installation of a vent, and some at air-to-soil interfaces.

4. Northern Natural Gas has experienced no instances in which other pipeline segments required repair. Northern added that corrosion wall loss requiring repair is, itself, rare.

5. Paiute and Southwest Gas reported that they had not identified any immediate repair corrosion conditions.

Response to Question F.2 Comments

PHMSA appreciates the information provided by the commenters. See the response to question F.1.

F.3. Do pipeline operators assure that their risk assessments are updated as additional knowledge is gained, including results of IM assessments? If so, how? How is data integration used and how often is it updated? Is data integration used on alignment maps and layered in such a way that technical reviews can identify integrity-related problems and threat interactions? How often should aerial photography and patrol information be updated for IM assessments? If the commenter proposes a time period for updating, what is the basis for this recommendation?

1. INGAA and several pipeline operators reported that operators update risk analyses whenever new information is obtained and particularly after unexpected events.

2. AGA, GPTC, Nicor, Kern River, and TransCanada commented that risk analyses are updated at least annually.

3. Northern Natural Gas reported that its procedures provide for updating to include assessment results and changes in environmental factors.

4. Paiute and Southwest Gas reported that risk model updating is a continuous process. Rankings are updated at 18- to 24-month intervals. Ameren Illinois and Atmos similarly reported that updating is an ongoing activity.

5. Texas Pipeline Association and Texas Oil & Gas Association commented that most operators have dedicated teams to perform risk model updates.

6. Alaska Department of Natural Resources commented that risk models should be reviewed whenever significant operational or environmental changes occur. AKDNR contended that risk models are not valid if there are significant changes in these areas.

7. NAPSR reported its conclusion that risk models should be updated after every O&M activity or any finding that a required activity was not performed.

8. INGAA and a number of pipeline operators reported that data is updated using a common spatial reference system, *e.g.,* maps or tables, and the frequency of data integration varies by operator.

9. AGA, supported by a number of its member companies, reported that data integration does not always involve use of geospatial tools.

10. Atmos reported that it uses internal teams of subject matter experts for data integration and that its maps are not layered for technical data use.

11. Northern Natural Gas, Paiute, and Southwest Gas stated that they perform integration on alignment sheets based on integrity management summaries and subject matter expert reviews.

12. Texas Pipeline Association and Texas Oil & Gas Association reported that many pipeline operators are migrating to GIS systems.

13. INGAA and many pipeline operators commented that information from aerial photography should be updated annually. They noted that this would be consistent with the frequency of reviewing HCA designations and operator budgeting and contended that more frequent updates would not increase risk model accuracy. INGAA suggested that other information, including information related to external events, should be updated based on the nature and severity of experienced events.

14. AGA, Paiute, and Southwest Gas noted that not all operators use aerial photography and expressed their belief that such use should not be required. AGA noted that there are many tools, including routine patrols, to gather data about the pipeline environment. A number of member pipeline operators supported AGA's comments.

15. Northern Natural Gas reported that it updates information periodically, but with no set frequency. Northern noted that some areas are stable while change can occur rapidly in others.

16. Texas Pipeline Association and Texas Oil & Gas Association recommended annual updates as a minimum. The associations noted that this recognizes the time required to produce/acquire assessment data.

Response to Question F.3 Comments

PHMSA appreciates the information provided by the commenters. After review of the comments, PHMSA agrees that annual updates are desirable and many operators perform full updates, or partial data updates (such as updating aerial photos), annually. Some pipeline segments may be in rapidly changing, dynamic environments, while others may remain static for years. PHMSA also agrees that prescriptive requirements to perform a full risk assessment annually are not necessary and potentially burdensome, especially for very small operators, whose systems and conditions do not change often. PHMSA is satisfied that the current requirement, which contains a performance based requirement to update risk assessments as frequently as needed to assure the integrity of each HCA segment is adequate, if properly implemented, and is not proposing a prescribed frequency at this time. However, PHMSA proposes to clarify requirements in §§ 192.917 and 192.937(b) to ensure the continual process of evaluation and assessment is based on an updated and effective data integration and risk assessment process as specified in § 192.917.

F.4. Should the regulations specify a maximum period in which pipeline risk assessments must be reviewed and validated as current and accurate? If so, why?

1. INGAA and numerous pipeline operators recommended that reviews be annual, as suggested in PHMSA's Gas Integrity Management Program Frequently Asked Question FAQ–234, arguing that this is practical and sufficient (FAQs can be viewed at *http://primis.phmsa.dot.gov/gasimp/faqs.htm*).

2. AGA, GPTC, and a number of other pipeline operators commented that no maximum period should be specified for review of risk assessments. These commenters argued that no one-size-fits-all interval would be appropriate and expressed their conclusion that the current requirements in § 192.937 are adequate.

3. California Public Utilities Commission recommended that reviews be required annually, at intervals not to exceed 15 months, consistent with other requirements within part 192.

4. An anonymous commenter suggested that a specified review period would be counterproductive, arguing that most operators would simply default to the required interval, even if more frequent reviews were appropriate.

Response to Question F.4 Comments

PHMSA appreciates the information provided by the commenters. See PHMSA response to comments related to Question F.3.

F.5. Are there any additional requirements PHMSA should consider to assure that knowledge gained through IM programs is appropriately applied to improve safety of pipeline systems?

1. INGAA and many pipeline operators opined that no new requirements are needed in this area. They noted that prescriptive requirements often become out of date as technology improves.

2. AGA and numerous pipeline operators agreed that no new requirements are needed, noting that existing regulations and sharing of information through industry groups is sufficient.

3. Texas Pipeline Association and Texas Oil & Gas Association opined that existing requirements are adequate.

4. Accufacts suggested that requirements should be more prescriptive concerning threat evaluation and interactive threats, as this is the heart of integrity management.

5. An anonymous commenter suggested that new requirements be established governing assessments conducted by pressure testing. The commenter opined that the requirements in subpart J are inadequate and represent an ''easy out'' for some operators.

Response to Question F.5 Comments

PHMSA appreciates the information provided by the commenters. While PHMSA believes that explicit requirements should be included to address interactive threats, PHMSA also believes that prescriptive rules for how an operator must evaluate interactive threats are not practical. Therefore, PHMSA proposes to clarify performance-based requirements to include an evaluation of the effects of interacting threats and for the continual process of evaluation and assessment to include interacting threats in identification of threats specific to each HCA segment. Comments on integrity assessment methods are addressed in Topic G.

F.6. What do operators require for data integration to improve the safety of pipeline systems in HCAs? What is needed for data integration into pipeline knowledge databases? Do operators include a robust database that includes: Pipe diameter, wall thickness, grade, and seam type; pipe coating; girth weld coating; maximum operating pressure (MOP); HCAs; hydrostatic test pressure including any known test failures; casings; any in-service ruptures or leaks; ILI surveys including high resolution—magnetic flux leakage (HR–MFL), HR geometry/caliper tools; close interval surveys; depth of cover surveys; rectifier readings; test point survey readings; alternating current/direct current (AC/DC) interference surveys; pipe coating surveys; pipe coating and anomaly evaluations from pipe excavations; SCC excavations and findings; and pipe exposures from encroachments?

1. INGAA, supported by a number of pipeline operators, commented that experience and information gained from a variety of sources, including GIS data, corrosion data, ILI data/results, work management activities, SCADA, encroachments, leaks etc., is utilized in data integration. INGAA reported that operators have made major investments

in database applications to meet changing organizational and regulatory requirements and to manage increasing volumes of data effectively. Tools generally are available for integrating data into pipeline knowledge databases. For integration purposes, the database must contain adequate metadata elements such that dates, if important, and location and length attributes are maintained. Currently-available systems support these needs. INGAA expressed concern over use of the term ''robust database,'' since this could be construed to mean that all applicable data must be maintained in a common database or other venue which does not meet the particular needs of the operator. INGAA reported that it has an active Integrity Management—Continuous Improvement (IMCI) team addressing improvement in these processes and management systems.

2. AGA, GPTC, and a number of pipeline operators commented that a prescriptive requirement would be inappropriate because there is too much variability among operators and their risk assessment methods. AGA expressed its conclusion that there is no single methodology that incorporates the wide variety of pipeline information used by operators.

3. MidAmerican suggested that an operator needs a robust computer model to integrate diverse data dynamically into one table with one set stationing.

4. Kern River reported that it uses extensive GIS and cathodic protection databases for these purposes.

5. An anonymous commenter recommended that PHMSA require knowledge of cathodic protection current level, amount, and direction of current flow. The commenter opined that this information is not now generally collected, and that it would allow for early detection of coating failures and CP interferences.

Response to Question F.6 Comments

PHMSA appreciates the information provided by the commenters. An integral part of applying information from the IM Program to the risk assessment and other analyses is the collection, validation, and integration of pipeline data. PHMSA proposes to clarify the data integration language in the requirements by repealing the reference to ASME/ANSI B31.8S and including requirements associated with data integration directly in the rule text: (1) Establishing a number of pipeline attributes that must be included in these analyses, (2) clarifying that operators must integrate analyzed information, and (3) ensuring that data are verified and validated.

F.7. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

G. Strengthening Requirements on the Selection and Use of Assessment Methods

The existing IM regulations require that baseline and periodic assessments of pipeline segments in an HCA be performed using one of four methods:

(1) In-line inspection;

(2) Pressure test in accordance with subpart J;

(3) Direct assessment to address the threats of external and internal corrosion and SCC; or

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe.

Operators must notify PHMSA in advance if they plan to use ''other technology.'' Operators must apply one or more methods, depending on the threats to which the HCA segment is susceptible. The ANPRM requested comments related to the applicability, selection, and use of each assessment method, existing consensus standards and requirements, and the potential need to strengthen the requirements. The ANPRM then listed questions for consideration and comment. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic G

1. INGAA, supported by a number of its pipeline operator members, noted that they are committed to work with technology providers and researchers to improve the integrity management assessment capabilities of its members. Further, INGAA members are sharing their experiences with applying these new and improved assessment methods to specific threats. INGAA opined that a great advantage of the integrity management structure, as opposed to a prescriptive regulatory regime, is the creation of an environment conducive to technological development, innovation and improved knowledge.

2. Accufacts suggested that a more prescriptive regulation is needed clarifying the applicability and limitations of direct assessment. Accufacts is concerned that operators are selecting direct assessment due to a cost bias while ignoring that it cannot be used for all threats and should not be used on some pipeline segments.

3. Chevron commented that PHMSA should continue to allow operators to select and use the most effective method to assess each pipeline segment.

4. NAPSR recommended that PHMSA implement a regulatory change that requires both ILI and pressure testing for all transmission pipelines and requires a reduction in MAOP until either the ILI or the pressure tests are performed.

5. MidAmerican, a gas distribution company, noted that many of its transmission pipelines are short, small diameter lines that cannot be pigged.

6. Dominion East Ohio suggested that PHMSA should be funding more research leading to the development of assessment tools, particularly smart tools, to increase the number of assessment options available rather than limiting the tools that can be used.

7. A public citizen commented that pipe with unknown or uncertain specifications should be subject to the most stringent testing requirements.

8. Two public citizens addressed required assessment intervals. One suggested that all pipe that puts the public at significant risk should be tested, by hydro testing or some other means, at approximately ten-year intervals. Another commenter recommended that assessments be required more frequently in densely populated areas.

9. PST opined that the need to ask the questions in this section makes clear that PHMSA's current level of oversight and review of IM planning and implementation is inadequate, and calls into question the value of many IM programs, particularly those relying to any extent on direct assessment methods. PST recommended that the regulations be significantly strengthened to require PHMSA's review and administration approval of any IM program.

Response

PHMSA appreciates the information provided by the commenters. PHMSA agrees that pipeline operators should be able to select the best assessment

method applicable for its pipelines and circumstances. PHMSA also agrees with NAPSR and other commenters that additional requirements are needed for assessing more miles of pipeline that pose a risk to the public. PHMSA has also identified the need to address specific issues related to the selection of integrity assessment methods that have been identified following the San Bruno incident, especially related to the use of direct assessment. Therefore, PHMSA proposes to add more specific requirements related to (1) performance of integrity assessments for pipe not covered by subpart O (*i.e.,* pipeline not located in a high consequence area) that represents risk to the public, and (2) selection of assessment methods. Specifically, PHMSA proposes to revise the requirements in §§ 192.921 and 192.937 as follows: (1) Allow direct assessment only if a line is not capable of inspection by internal inspection tools; (2) add a newly defined assessment method: ''spike'' hydrostatic test; (3) add excavation and *in situ* direct examination as an allowed assessment method; and (4) add guided wave ultrasonic testing (GWUT) as an allowed assessment method. In addition, PHMSA proposes to add a new § 192.710 to require that a significant portion of pipelines not covered by subpart O be periodically assessed using integrity assessment techniques similar to those proposed for HCA segments. Specifically, PHMSA proposes to require that all pipeline segments in class 3 and class 4 locations and moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''), be periodically assessed. Although PHMSA proposes to provide selected, more prescriptive requirements for the selection of assessment methods, the pipeline safety regulations would continue to allow the use of other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe (comparable to a specified integrity assessment such as pressure testing or inline inspection), in order to continue to encourage research and development of more effective assessment technologies similar to the successful development of GWUT. For non-HCA segments, operator notification to PHMSA of the selection of other technologies would not be required.

PHMSA understands the Pipeline Safety Trust's recommendation that the regulations require PHMSA's review and approval of any IM program. PHMSA believes its current approach to inspection of operator IM programs is both flexible and appropriate.

Comments Submitted for Questions in Topic G

G.1. Have any anomalies been identified that require repair through various assessment methods (e.g., number of immediate and total repairs per mile resulting from ILI assessments, pressure tests, or direct assessments)?

1. INGAA reported that operators have used in-line inspection, pressure testing, and direct assessment, with in-line inspection being most prevalent. INGAA commented that all three methods have been successful at identifying anomalies requiring repair. A number of pipeline operators supported INGAA's comments.

2. AGA and Ameren Illinois stated that all assessment methods used by pipeline operators have been used to identify, or have identified, anomalies requiring repair. A number of pipeline operators supported AGA's comments.

3. Accufacts recommended that PHMSA publically report the number of anomalies discovered and repaired by anomaly type, time to repair, state, and assessment method for both HCAs and non-HCAs.

4. Texas Pipeline Association, Texas Oil & Gas Association, Atmos, Paiute, and Southwest Gas noted that the transmission pipeline annual report includes the number of immediate and scheduled anomalies identified by each assessment method.

5. ITT Exelis Geospatial Systems reported that aerial leak surveys using laser technology, which is not one of the assessment methods specified in the regulations, have been successful in identifying pipeline leaks.

6. Kern River reported that it did not identify any immediate or scheduled repairs from January 1, 2004, through December 31, 2010.

7. MidAmerican noted that it has used all three allowed assessment methods. Approximately 42 percent of the company's pipeline has been assessed using direct assessment. All anomalies requiring repair have been identified using in-line inspection.

8. Northern Natural Gas reported that it identified seven immediate repair anomalies in the period from January 1, 2004, through December 31, 2010. The total number of repairs made during this same period averaged 0.1 per mile.

9. An anonymous commenter noted that few leaks are detected using subpart J pressure testing.

10. GPTC reported that it has no data with which to respond to this question.

Response to Question G.1 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that all three methods have been successful at identifying anomalies requiring repair. However, by its nature, direct assessment is a sampling-type assessment method. Hydrostatic pressure testing and in-line inspection both assess the entire segment. PHMSA, therefore, believes that these methods provide a higher level of assurance (though still not 100%) that no injurious pipeline defects remain in the pipe after the assessment is completed and anomalies repaired. Based on this inherent difference, PHMSA proposes to revise the requirements to: (1) Allow direct assessment only if a line is not capable of inspection by internal inspection tools; (2) add a newly defined assessment method: ''spike'' hydrostatic test; (3) add excavation and *in situ* direct examination as an allowed assessment method; and (4) add guided wave ultrasonic testing (GWUT) as an allowed assessment method.

G.2. Should the regulations require assessment using ILI whenever possible, since that method appears to provide the most information about pipeline conditions? Should restrictions on the use of assessment technologies other than ILI be strengthened? If so, in what respect? Should PHMSA prescribe or develop voluntary ILI tool types for conducting integrity assessments for specific threats such as corrosion metal loss, dents and other mechanical damage, longitudinal seam quality, SCC, or other attributes?

1. INGAA, supported by a number of its pipeline operator members, noted that ILI is effective, but has its own limitations; pressure testing and direct assessment can provide information that ILI cannot. INGAA commented that operators must be allowed to use all assessment techniques without encumbrances or conditions because all techniques are effective.

2. AGA and a number of its members commented that ILI is one option of a variety of methods available to operators and suggested that applying additional ILI assessment requirements would hinder operators' ability to select the tool with the appropriate capabilities to address pipeline threats. AGA commented that this would be inappropriate and operators must be allowed to use any of the three assessment methods, without conditions, based on the circumstances and threats applicable to their pipelines.

3. Air Products and Chemicals, Inc. opposed a requirement to use ILI whenever possible. The company noted

that one of the benefits of the current IM framework is the flexibility it provides to operators in how to achieve regulatory goals. Air Products noted that use of alternative methods is already constrained by regulation and contended that the existing limitations are adequate and it would be inappropriate for PHMSA to specify particular tool types for individual threats. Atmos agreed, noting that ILI is not the only assessment method applicable to many threats. Atmos noted that ILI technology is developing at a rapid pace, and suggested that prescribing certain tool types could limit future advancements or cause the rate of development to be slowed.

4. TransCanada opposed requiring use of ILI. The company noted that ILI has its advantages, but it also has limitations, and commented that operators must be able to select the methods best suited to evaluate identified threats, given the wide range of circumstances and threats that may be applicable to particular pipeline segments.

5. NACE International noted that assessments using only ILI do not necessarily provide the most information about pipeline conditions; other assessment methods may be more appropriate for some threats. NACE also noted that not all pipelines are piggable. NACE believes that each assessment method has strengths and weaknesses, each should be used where appropriate, and overly prescriptive rules can supplant sound engineering judgment, stifle innovation, and prevent the development of new technologies.

6. Accufacts commented that all new pipelines should be configured to permit ILI and a timetable should be established to convert older pipelines for ILI. At the same time, Accufacts cautioned that one particular approach to ILI should not be oversold, and suggested that limitations on use of certain assessment methods should be strongly clarified in regulations. Accufacts suggested that PHMSA needs to clarify the major strengths and weaknesses of the various assessment methods identified and to improve subpart J, including requiring the reporting of hydro testing pressure ranges, both minimum and maximum pressures, as a percentage of SMYS when appropriate.

7. MidAmerican suggested that operators be allowed to address threats by category using the guidance in ASME/ANSI B31.8S. MidAmerican noted that it cannot use ILI on all of its transmission pipelines, 42 percent of which have been assessed using direct assessment. MidAmerican suggested that operators continue to use their threat assessments to determine which pipelines should be retrofitted to accommodate ILI.

8. Northern Natural Gas reported that it uses ILI whenever possible but it cannot be used on all of its lines due to their small diameter. Northern noted that pressure testing and direct assessment may be more appropriate for some threats and that the operator is responsible for selecting the best assessment method. Northern opined that the guidance on tool selection in ASME/ANSI B31.8S is sufficient.

9. Texas Pipeline Association and Texas Oil & Gas Association recommended that ILI not be the required assessment method of choice and that operators continue to have the flexibility to select the appropriate assessment method, noting that other methods may be better for a particular threat. The associations noted that ILI technology is improving rapidly and expressed concern that rulemaking cannot keep pace with technological advancement and that prescribing tools could result in assessments being conducted with inferior technology.

10. Thomas M. Lael, an industry consultant, noted that no assessment method, including ILI, is perfect. Lael suggested that use of alternating methods be required to realize the strengths of all methods.

11. A citizen commenter suggested that use of direct assessment be limited, since it does not provide sufficient information about the pipeline.

12. An anonymous commenter noted that requiring ILI would not be cost beneficial, because corrosion metal loss is a relatively slow process.

13. GPTC noted that ILI cannot be used on all pipelines and recommended that operators have the latitude to select the assessment method most appropriate for their pipelines. Oleksa and Associates similarly noted that ILI cannot be used on some pipelines.

14. Paiute and Southwest Gas opposed a requirement to use ILI whenever possible. The companies noted that ILI provides current pipe conditions but no information on environmental conditions surrounding the pipe. They commented that operators should not be discouraged from using any appropriate assessment method.

15. Ameren Illinois opposed requiring the use of ILI, noting that it is neither practical nor feasible to require ILI assessments on all pipelines.

16. California Public Utilities Commission recommended that pressure testing and ILI be the only methods allowed for IM assessments. CPUC suggested that the use of direct assessment be limited to confirmatory direct assessments and lines that have been pressure tested to subpart J requirements. CPUC further recommended that the regulations prescribe acceptable ILI tool types to address specific threats.

17. A private citizen suggested that pressure testing should not be allowed as an assessment method because it provides no information about anomalies not resulting in leaks or failures. The commenter suggested that use of pressure testing should be limited to verifying the integrity of new or repaired pipelines.

Response to Question G.2 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that operators should be able to select the methods best suited to evaluate identified threats. However, PHMSA believes rulemaking for strengthening requirements for the selection and use of assessment methods is needed to address specific issues identified from the San Bruno incident. PHMSA proposes more prescriptive guidance for the selection of assessment methods, especially related to the use of direct assessment and to assess for cracks and crack-like defects, as indicated in the response to general comments, above. For HCA segments, PHMSA proposes that the use of direct assessment as the assessment method would be allowed only if the pipeline is not capable of being inspected by internal, in-line inspection tools. For non-HCA segments, assessments would have to be done within 15 years and every 20 years thereafter. To facilitate the identification of non-HCA areas that require integrity assessment, PHMSA proposes to define a ''Moderate Consequence Area'' or MCA. PHMSA also proposes additional requirements for selection and use of internal inspection tools, including a requirement to explicitly consider uncertainties such as tool tolerance in reported results in identifying anomalies.

PHMSA disagrees with the suggestion that pressure testing should not be allowed as an assessment method. In many circumstances, pressure testing is a good indicator of a pipeline's integrity. Although it does not assess subcritical defects, it provides assurance of adequate design safety margin and can be useful in particular for lines that are not piggable.

G.3. Direct assessment is not a valid method to use where there are pipe properties or other essential data gaps. How do operators decide whether their

knowledge of pipeline characteristics and their confidence in that knowledge is adequate to allow the use of direct assessment?

1. Industry commenters, including AGA, INGAA, Texas Pipeline Association, Texas Oil and Gas Association, and numerous pipeline operators noted that the requirements applicable to direct assessment, specified in NACE Standard SP0502–2008 and incorporated into subpart O by reference, require a feasibility study to determine if use of direct assessment is appropriate. If it cannot be determined during the pre-assessment phase that adequate data is available, another assessment method must be selected. Industry commenters noted that it is the operator's responsibility to select an appropriate assessment method.

2. Paiute and Southwest Gas disagreed with the statement that ''direct assessment is not a valid method to use where there are pipe properties or other essential data gaps.'' The companies noted that the data gathered and evaluated conforms to Section 4 of ASME/ANSI B31.8S (incorporated by reference) which allows use of conservative proxy values when data gaps exist.

3. California Public Utilities Commission recommended that pressure testing and ILI be the only methods allowed for IM assessments. CPUC suggested that use of direct assessment be limited to confirmatory direct assessments and lines that have been pressure tested to subpart J requirements.

Response to Question G.3 Comments

PHMSA appreciates the information provided by the commenters. PHMSA agrees that pressure testing and ILI are preferred integrity assessment methods, over direct assessment. However, when properly implemented, DA can be a valuable integrity assessment tool. PHMSA proposes to retain direct assessment as an assessment method where warranted, but proposes to revise the requirements in §§ 192.921 and 192.937 to allow use of direct assessment or other method only if a line is not capable of inspection by internal inspection tools.

G.4. How many miles of gas transmission pipeline have been modified to accommodate ILI inspection tools? Should PHMSA consider additional requirements to expand such modifications? If so, how should these requirements be structured?

1. A number of industry commenters submitted data concerning the number of pipeline miles that have been modified to accommodate ILI:

- INGAA reported that more than 30,000 miles of pipeline have been modified across the industry.
- Atmos reported that it has modified approximately 2,800 miles.
- Northern Natural Gas reported that it has modified approximately 2,500 miles.
- MidAmerican reported that it has modified 38 miles.
- Paiute and Southwest Gas reported that they have made modifications but have not tracked the total mileage on which they were performed.
- Ameren Illinois and Kern River reported that they have modified no pipelines. Kern River noted specifically that all of its mainline is piggable.

2. AGA reported that it has no data concerning the number of miles modified, but noted that operators are required to assure that new and replaced pipelines can accommodate ILI tools. AGA contended that modifying pipelines to accommodate ILI tools is more onerous for intrastate transmission pipeline operators than for interstate operators. A number of operators supported AGA's comments.

3. Texas Pipeline Association and GPTC reported that they have no data with which to respond to this question.

4. California Public Utilities Commission supported additional requirements to expand modifications to accommodate ILI but reported that it has no opinion on how these requirements should be structured.

5. MidAmerican noted that one-third of its 770 miles of transmission pipeline is of a diameter smaller than available ILI tools.

6. Northern Natural Gas commented that PHMSA should not consider additional requirements to expand modifications of pipelines to accommodate ILI tools, and that the inspection method and determination to assess additional line segments outside of HCAs should be based on specific risk factors and type and configuration of pipeline facility. The company noted that some lines cannot be assessed using ILI.

7. Paiute and Southwest Gas noted that § 192.150 requires that newly constructed or replacement pipelines be designed to accommodate ILI tools. They contended that the decision to modify other pipelines should be an operator decision based on the best assessment method.

8. Texas Pipeline Association and Texas Oil & Gas Association opined that PHMSA does not need to develop additional requirements for the modification of transmission pipelines to accommodate ILI tools. The associations noted that the regulations already cover this for new and replacement pipelines and that there is a financial incentive for operators to use ILI tools versus other assessment methods. Atmos agreed, also noting that there are numerous advantages to ILI that incentivize operators to use that method when they can.

9. Accufacts commented that PHMSA should report publicly the number of miles of transmission pipeline that can be inspected by ILI as well as the number of miles inspected by other assessment methods both for HCAs and non-HCAs.

Response to Question G.4 Comments

PHMSA appreciates the information provided by the commenters. In its report on the San Bruno incident, the NTSB recommended that all natural gas transmission pipelines be configured so as to accommodate in-line inspection tools, with priority given to older pipelines (recommendation P–11–17). In its initial response to the NTSB recommendation, PHMSA stated that implementing this recommendation will involve significant technical and economic challenges and is likely to require time to implement. Additional data is needed to evaluate this issue. Therefore, further rulemaking will be considered separately in order to complete this evaluation. PHMSA will review the comments received on the ANPRM and will address this issue in the future.

G.5. What standards are used to conduct ILI assessments? Should these standards be incorporated by reference into the regulations? Should they be voluntary?

1. INGAA, supported by a number of its operator members, noted that standards are continuously upgraded and improved and recommended that PHMSA adopt performance-based language that will allow operators to select appropriate standards.

2. AGA, supported by a number of its members, noted that ILI technology is advancing rapidly and it would be unwise to restrict innovation by handcuffing it to a slow-developing rulemaking process. AGA recommended that PHMSA not adopt ILI standards into the code. Ameren Illinois agreed that standards should not be incorporated, because to do so would limit operators' ability to use up-to-date standards.

3. GPTC argued that there is no justification to enact additional prescriptive regulations for ILI assessments of pipelines. GPTC contended that performance standards allow operators to select the best approach.

4. Atmos, MidAmerican, Northern Natural Gas, Paiute, and Southwest Gas all cited one or more of API1163, ASNT ILI–PQ–2005 and RP0102–2002, and ASME/ANSI B31.8S as standards used to conduct ILI assessments. All agreed that use of industry standards should remain voluntary. Paiute and Southwest Gas, in particular, commented that technology is developing rapidly, and that incorporating current standards into the regulations may hold operators accountable to a level of performance that may be outdated.

5. Texas Pipeline Association and Texas Oil & Gas Association also opposed incorporating ILI standards into the regulations. TPA commented that there are incentives for operators to take appropriate measures to obtain accurate and reliable ILI results.

6. An anonymous commenter suggested that incorporating standards could be counterproductive, since operators would usually stop with the required actions. The commenter suggested that a better approach would be to require operators to have precise specifications, guidelines, and a written process for ILI, none of which should be developed by the operator's ILI vendor. The commenter also suggested that a similar approach be adopted for stress corrosion cracking direct assessment (SCCDA).

7. California Public Utilities Commission and a private citizen recommended that standards be incorporated for mandatory compliance, arguing that this is necessary to assure quality and accuracy.

Response to Question G.5 Comments

PHMSA appreciates the information provided by the commenters. The current pipeline safety regulations in 49 CFR 192.921 and 192.937 require that operators assess the material condition of pipelines in certain circumstances and allow use of in-line inspection tools for these assessments. Operators are required to follow the requirements of ASME/ANSI B31.8S in selecting the appropriate ILI tools. ASME B31.8S provides limited guidance for conducting ILI assessments. At the time these rules were promulgated, there was no consensus industry standard that addressed ILI. Three related standards have been published: API STD 1163–2005, NACE SP0102–2010, and ANSI/ASNT ILI–PQ–2010. These standards address the qualification of inline inspection systems, the procedure for performing ILI, and the qualification of personnel conducting ILI, respectively. The incorporation of these standards into pipeline safety regulations will promote a higher level of safety by establishing consistent standards. Therefore, PHMSA is proposing to incorporate these industry standards into the regulations to provide better guidance for conducting integrity assessments with in-line inspection. PHMSA also encourages and actively supports the development of new and better technology for integrity assessments. Therefore, the rule also allows the application and use of new technology, provided that PHMSA is notified in advance. PHMSA will continue to evaluate the need for additional guidance for conducting integrity assessments or applying new technology.

G.6. What standards are used to conduct internal corrosion direct assessment (ICDA) and SCCDA assessments? Should these standards be incorporated into the regulations? If the commenter believes they should be incorporated into the regulations, why? What, if any, remediation, hydrostatic test or replacement standards should be incorporated into the regulations to address internal corrosion and SCC?

1. INGAA commented that standards exist for ICDA and SCCDA. AGA agreed that NACE SP0206 addresses ICDA and SP0204 addresses SCCDA. AGA opposed adopting these standards into the regulations, however, commenting that a standard must be demonstrated to be effective before it can be incorporated. AGA noted that there are long-standing issues with the ICDA standard. Numerous pipeline operators provided comments supporting the INGAA and AGA comments.

2. GPTC, Atmos, Ameren Illinois, MidAmerican, Paiute, Southwest Gas, Texas Gas Association and Texas Oil & Gas Association all referenced one or more of: NACE SP0502, NACE SP0206, ASME/ANSI B31.8S, and GRI02–0057. All agreed that the standards should not be incorporated by reference, arguing that this would stifle innovation or require operators to follow requirements that may become outdated, or both. Paiute and Southwest Gas specifically recommended that PHMSA collect additional information on industry best practices and compile/review IM results related to internal corrosion and SCC before taking any action towards incorporating the standards.

3. NACE International reported its conclusion that the existing standards for ICDA and SCCDA should be incorporated into regulations. NACE also cautioned that overly-prescriptive regulations can prevent innovation and development of new technologies.

4. Northern Natural Gas reported that it used NACE SP0206 in developing its ICDA procedures and there would be no impact on the company if the standard were adopted into regulations. Northern further reported it does not use SCCDA.

5. Accufacts commented that few technical gains have been made in the abilities of direct assessment methods to reliably identify or assess at-risk anomalies, especially with regards to SCC.

6. California Public Utilities Commission argued that pressure testing and ILI should be the only assessment methods allowed. The Commission contended that direct assessment should be limited to use during confirmatory direct assessments and for lines that have been pressure tested to subpart J requirements.

7. An anonymous commenter noted that Kiefner, NACE, and ASTM all provide useful references for SCCDA and ICDA.

8. INGAA, supported by several of its operator members, noted that ASME/ANSI B31.8S addresses remediation and pressure testing. INGAA recommended that PHMSA adopt the 2010 version of this standard, arguing that it is improved over the 2004 standard that is currently incorporated by reference into Section 192.7 and that it addresses near-neutral SCC. The 2010 edition also includes specific guidance for SCC mitigation by means of hydrostatic pressure testing in the event SCC is identified on a pipeline.

9. MidAmerican reported that it uses ASME B31G to determine remaining wall strength and that it remediates conditions in accordance with § 192.933(d) and ASME/ANSI B31.8S.

Response to Question G.6 comments

PHMSA appreciates the information provided by the commenters. Section 192.927 specifies requirements for gas transmission pipeline operators who use ICDA for IM assessments. The requirements in § 192.927 were promulgated before there were consensus standards published that addressed ICDA. Section 192.927 requires that operators follow ASME/ANSI B31.8S provisions related to ICDA. PHMSA has reviewed NACE SP0206–2006 and finds that it is more comprehensive and rigorous than either § 192.927 or ASME B31.8S in many respects. In addition, Section 192.929 specifies requirements for gas transmission pipeline operators who use SCCDA for IM assessments. The requirements in § 192.929 were promulgated before there were consensus industry standards published that addressed SCCDA. Section 192.929 requires that operators follow Appendix A3 of ASME/ANSI B31.8S. This appendix provides some guidance for

conducting SCCDA, but is limited to SCC that occurs in high-pH environments. Experience has shown that pipelines also can experience SCC degradation in areas where the surrounding soil has a pH near neutral (referred to as near-neutral SCC). NACE Standard Practice SP0204–2008 addresses near-neutral SCC in addition to high-pH SCC. In addition, the NACE recommended practice provides technical guidelines and process requirements which are both more comprehensive and rigorous for conducting SCCDA than either § 192.929 or ASME/ANSI B31.8S. Therefore, PHMSA is proposing to incorporate these industry standards into the regulations to provide better guidance for conducting integrity assessments with ICDA or SCCDA. PHMSA will continue to evaluate the need for additional guidance for conducting integrity assessments.

G.7. Does NACE SP0204–2008 (formerly RP0204), ''Stress Corrosion Cracking Direct Assessment Methodology'' address the full life cycle concerns associated with SCC?

1. INGAA suggested NACE SP0204, by itself, does not address the full life cycle concerns of SCC but in combination with ASME/ANSI B31.8S the full life cycle concerns are addressed. A number of pipeline operators supported INGAA's comments.

2. AGA, supported by a number of its members, suggested PHMSA should determine whether NACE SP0204 addresses full life cycle concerns.

3. GPTC, Texas Pipeline Association, Texas Oil & Gas Association, and Ameren Illinois commented it was not clear what PHMSA meant by ''full life cycle concerns.''

4. NACE International reported that SP0204 does not address the full life cycle concerns of SCC; however, NACE noted that it has developed a 2011 ''Guide to Improving Pipeline Safety by Corrosion Management'' which will be converted into a NACE standard.

5. MidAmerican reported its conclusion that NACE SP0204 does address full life cycle concerns.

6. Paiute and Southwest Gas reported their conclusion that the existing standards are adequate, but deferred to NACE concerning the breadth of coverage of NACE standards.

Response to Question G.7 Comments

PHMSA appreciates the information provided by the commenters. PHMSA believes that NACE SP0204–2008 is the best available guidance and is proposing to incorporate this industry standard into the regulations for conducting integrity assessments with SCCDA. In addition, other proposed requirements for integrity assessments and remediation in §§ 192.710, 192.713, 192.624, and subpart O provide greater assurance that the full life cycle concerns associated with SCC are addressed.

G.8. Are there statistics available on the extent to which the application of NACE SP0204–2008, or other standards, have affected the number of SCC indications operators have detected and remediated on their pipelines?

1. Industry commenters responding to this question unanimously noted that no statistics have been collected on the use of NACE SP0204. INGAA noted, in addition, that the SCC Joint Industry Project (JIP) represents the experience of operators of 160,000 miles of gas transmission pipeline.

2. Paiute and Southwest Gas reported that they have not identified any SCC on their pipeline systems.

3. An anonymous commenter noted that there has been one incident attributed to factors not addressed in current standards. The commenter noted that the only common factors among SCC colonies was high soil resistivity and disbanded coating.

Response to Question G.8 Comments

PHMSA appreciates the information provided by the commenters. As described in the response to Question G.6, PHMSA is proposing to incorporate NACE SP0204–2008 into the regulations. PHMSA will continue to gather information in this area and will evaluate the need for more specific requirements or guidance to address the threat of SCC.

G.9. Should a one-time pressure test be required to address manufacturing and construction defects?

1. INGAA and a number of its pipeline operators argued that this should be a case-by-case decision guided by INGAA's Fitness for Service protocol. INGAA noted that new pipelines require a part 192, subpart J, pressure test while older pipelines may have been strength tested.

2. AGA, supported by a number of its pipeline operators, opined that a one-time pressure test is sufficient. AGA noted that Congress accepted the stability of pipelines that had undergone a post construction pressure test.

3. GPTC argued that a one-time pressure test is sufficient; however, such a test should not be mandated for pipelines not tested after construction unless a significant risk has been demonstrated. GPTC noted that manufacturing and construction defects are not time-related.

4. American Public Gas Association objected to any requirement for a one-time pressure test, noting that it is not practical to conduct such a test on most transmission pipelines operated by municipal pipeline operators.

5. Atmos noted that the decision to perform one-time pressure tests to address manufacturing and construction defects requires more information and consideration than can be conveyed in response to a single question. Atmos reported that it could not determine if the one-time pressure test requirement would apply to all pipeline segments or to pipelines with certain characteristics. Some of Atmos' pipelines could not be removed from service for testing without impacts on customers.

6. Ameren Illinois argued that no one-time pressure test should be required, noting that a pressure test is already required before a pipeline is placed in service.

7. Northern Natural Gas argued that a one-time pressure test should not be required in all cases. Northern noted that assessment of manufacturing and construction defect threats should be determined based on the risk level and pipeline type for pipeline segments do not have an existing pressure test.

8. MidAmerican opined that a one-time pressure test should be a requirement for manufacturing and construction defects, noting defects that survive a pressure test are unlikely to fail during the useful life of the pipeline.

9. Oleksa and Associates noted that: (1) A one-time pressure test is all that is needed for manufacturing and construction defects; (2) an in-service pipeline should only be pressure tested if there is clear reason to believe a strength test would be beneficial; and (3) many pipelines operate at such low levels of stress that a strength test is not necessary.

10. Paiute and Southwest Gas commented that a pressure test should be conducted in accordance with subpart J when initially placing a pipeline in service. The operators reported that they support the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 which will require systematic pressure testing (or other alternative methods of equal or greater effectiveness) of certain, previously untested transmission pipelines located in HCAs and operating at a pressure greater than 30% SMYS. Texas Pipeline Association and Texas Oil & Gas Association agreed, noting that testing of new pipelines is already required and the Act requires use of pressure testing or alternate means to verify MAOP.

11. Thomas Lael and California Public Utilities Commission argued that all pipelines should be subjected to a pressure test. CPUC noted that an unspecified technical paper published by Kiefner shows that a pressure test to 1.25 times MAOP will be sufficient to demonstrate the stability of manufacturing and construction defects and girth welds.

12. The NTSB recommended that PHMSA amend part 192 so that manufacturing and construction defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP.

13. Accufacts suggested that a requirement for a one-time pressure test is needed, noting the NTSB safety recommendations issued following San Bruno made it clear that there are problems with the current IM regulations, especially as they relate to systems that were in operation before the implementation of federal regulations.

14. A private citizen suggested that a one-time pressure test or reduction of MAOP should be required for all low-frequency electric resistance welded (LFERW) pipe.

15. A private citizen suggested that a one-time pressure test conducted in combination with ILI should be required as a baseline for subsequent ILI inspections.

16. An anonymous commenter opined that no one-time pressure test is needed unless there is a history of seam failure or SCC.

Response to Question G.9 Comments

PHMSA appreciates the information provided by the commenters. The majority of comments support performance of a one-time pressure test to address manufacturing and construction defects. The ANPRM requested comments regarding proposed changes to part 192 regulations that would repeal 49 CFR 192.619(c) and the NTSB issued recommendations to repeal 49 CFR 192.619(c) for all gas transmission pipelines (P–11–14) and to require a pressure test before concluding that manufacturing- and construction-related defects can be considered stable (P–11–15). In addition, Section 23 of the Act requires issuance of regulations regarding the use of tests to confirm the material strength of previously untested natural gas transmission lines.

An Integrity Verification Process (IVP) workshop was held in 2013. At the workshop, PHMSA, the National Association of State Pipeline Safety Representatives, and various other stakeholders presented information and comments were sought on a proposed IVP that will help address these issues. Key aspects of the proposed IVP process include criteria for establishing which pipe segments would be subject to the IVP, technical requirements for verifying material properties where adequate records are not available, and technical requirements for re-establishing MAOP where adequate records are not available or the existing MAOP was established under § 192.619(c). Comments were received from the American Gas Association, the Interstate Natural Gas Association of America, and other stakeholders and addressed the draft IVP flow chart, technical concerns for implementing the proposed IVP, and other issues. The detailed comments are available on Docket No. PHMSA–2013–0119. PHMSA considered and incorporated the stakeholder input, as appropriate into this NPRM, which proposes requirements to address pipelines that established MAOP under 49 CFR 192.619(c), manufacturing and construction defect stability, verification of MAOP (where records that establish MAOP are not available or inadequate), and verification and documentation of pipeline material for certain onshore, steel, gas transmission pipelines.

G.10. Have operators conducted quality audits of direct assessments to determine the effectiveness of direct assessment in identifying pipeline defects?

1. INGAA, AGA, GPTC, and numerous pipeline operators noted that direct assessment is a cyclical process that continually incorporates analysis of information made available from the direct and indirect assessment tools used. The direct assessment process requires that more restrictive criteria be applied on first use and as operators become more experienced with the methodology and gather more data on the pipeline, more informed pipeline integrity decisions are made. The commenters stated that operators using the direct assessment process must continuously assess the effectiveness of the methodology.

2. Paiute and Southwest gas commented that operators confirm the findings of the pre-assessment and indirect assessment steps as part of the four-step direct assessment process. Validation digs are required to confirm the effectiveness of the direct assessment process.

3. Texas Pipeline Association and Texas Oil & Gas Association noted that direct examinations are made as part of every direct assessment. In Texas, operators have generally been required by the Railroad Commission to demonstrate comparisons of direct assessment results to ILI results on a portion of their pipeline where both have been performed. The associations contended that this process of validating should be considered a quality audit.

4. Northern Natural Gas agreed that verification of the effectiveness of direct assessment is already a part of the required post-assessment step of the four-step direct assessment process. Ameren Illinois agreed that this process is effectively a quality audit.

5. Atmos reported that records are kept of the indicated anomalies and the actual anomalies discovered through direct examination, thus assuring the quality and validation of direct assessments.

6. Accufacts opined that there appear to be serious deficiencies in the application of direct assessment on gas pipelines.

7. An anonymous commenter noted that direct assessment, if used correctly, is informative and proactive, and best suited to identify preventive and mitigative actions and to establish assessment intervals.

Response to Question G.10 Comments

PHMSA appreciates the information provided by the commenters. The majority of comments state that quality audits are performed for direct assessments, however, PHMSA believes, as one comment suggests, that there are weaknesses in the use of direct assessments. For example, SCCDA is not as effective, and does not provide an equivalent understanding of pipe conditions with respect to SCC defects, as ILI or hydrostatic pressure testing. Accordingly, PHMSA proposes to revise the requirements in §§ 192.921 and 192.937 for direct assessment to allow use of this method only if a line is not capable of inspection by internal inspection tools.

G.11. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

H. Valve Spacing and the Need for Remotely or Automatically Controlled Valves

The ANPRM requested comments regarding proposed changes to the requirements for sectionalizing block valves. Gas transmission pipelines are required to incorporate sectionalizing block valves. These valves can be used to isolate a section of the pipeline for maintenance or in response to an incident. Valves are required to be installed at closer intervals in areas where the population density near the pipeline is higher.

Sectionalizing block valves are not required to be remotely-operable or to operate automatically in the event of an unexpected reduction in pressure (*e.g.,* from a pipeline rupture). Congress has previously required PHMSA to ''assess the effectiveness of remotely controlled valves to shut off the flow of natural gas in the event of a rupture'' and to require use of such valves if they were shown technically and economically feasible.[36] The NTSB has also issued a number of recommendations concerning requirements for use of automatic- or remotely-operated mainline valves, including one following a 1994 pipeline rupture in Edison, NJ.[37] The incident in San Bruno, CA on September 9, 2010, has raised public concern about the ability of pipeline operators to isolate sections of gas transmission pipelines in the event of an accident promptly and whether remotely or automatically operated valves should be required to assure this.

The ANPRM then listed questions for consideration and comment. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic H

1. INGAA argued that while valves, spacing, and selection are important, public safety requires a broader review of incident responses and consequences. Performance-based Incident Mitigation Management (IMM), using valves and other tools, will, according to INGAA, improve incident response, reduce incident duration and minimize adverse impacts. IMM plans identify comprehensive actions that improve mitigation performance and minimize overall incident impact. These plans cover various aspects of response, including how operators detect failures, how they place and operate valves, how they evacuate natural gas from pipeline segments, and how they prioritize coordination efforts with emergency responders. A number of pipeline operators supported INGAA's comments, including Panhandle, TransCanada, Spectra Williams, Southern Star, and others.

2. AGA submitted a white paper that discussed potential benefits associated with remote control valves and automatic shutoff valves; however, the paper acknowledged that these valves will not prevent incidents. A number of pipeline operators supported AGA's comments.

3. APGA reported automatic or remotely-controlled valves are not practical for municipal pipeline operators because they do not have remote monitoring or control of their pipelines. APGA also cautioned that the use of automatic valves could lead to false closures, an unintended and adverse consequence.

4. Atmos commented that the existing requirements for valve spacing allow for safe and reliable service to its customers. The company noted that requiring the installation of remote control valves or automatic shutoff valves would add minimal value to the overall safety and operation of its transmission pipeline systems. In addition, industry studies have concluded that remote or automatic features on block valves would not reduce injuries or fatalities associated with an incident.

5. MidAmerican commented that installation of automatic shutoff valves would be costly, have minimal impact on improving safety, and could cause customer outages on its pipeline system. At the same time, MidAmerican acknowledged that some applications of remote/automatic control valves could have merit, but that the election should lie with the operator given the complexity of pipeline systems and other factors that bear on that decision. MidAmerican reported its conclusion that ASME/ANSI B31.8S provides adequate guidance for the installation of sectionalizing valves. While MidAmerican opposes a requirement to install automatic or remotely-controlled valves, the company suggested factors PHMSA should consider if it decides to adopt such a requirement. Specifically, PHMSA should allow operators flexibility in deciding between automatic and remote valves and should clarify when action on a pipeline is considered a new installation versus a repair or replacement in-kind.

6. TransCanada noted that industry studies have shown automatic or remote block valves do not prevent incidents and have a minimal effect on significant consequences, since most of the human impacts from a rupture occur in the first few seconds, well before any valve technology could reduce the flow of natural gas. TransCanada supports the use of Incident Mitigation Management (IMM) to improve incident response, reduce incident duration, and minimize adverse impacts.

7. Chevron argued operators should have the flexibility to select the most effective measures based on specific locations, risks, and conditions of the pipeline segment. Chevron noted that the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 requires a study of incident response in HCAs that must consider the swiftness of leak detection and pipeline shut-down capabilities and the location of the nearest personnel. The study must also evaluate the costs, risks, and benefits of installing automatic or remote controlled shut-off valves.

8. A private citizen suggested that periodic drills be held with local emergency responders, pipeline operators should provide specialized equipment to local responders in densely populated areas, and pipeline operators pay a fee to those municipalities to support incident response. The commenter further recommended that leak detection analyses be computerized.

9. Dominion East Ohio contended that current regulations are adequate and that automatic shutoff valves and remote control valves are an important preventive and mitigative measure to consider using. However, these valves do not prevent accidents and have very limited impact in preventing injuries and deaths caused by an initial pipeline failure.

10. Accufacts suggested that further prescriptive regulation is required concerning the placement, selection, and choice of manual, remotely-controlled, or automatic shutoff valves.

11. The Pipeline Safety Trust (PST) questioned the conclusions of the DOT study, ''Remotely Controlled Valves on Interstate Natural Gas Pipelines, (Feasibility Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996), September 1999, which concluded that remote control valves were and remain economically unfeasible. The PST noted that the study also stated that there could be a potential benefit in terminating the gas flow to a rupture

[36] Accountable Pipeline Safety and Partnership Act of 1996, Public Law 104–304.

[37] National Transportation Safety Board, ''Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994,'' PB95–916501, NTSB/PAR–95/01, January 18, 1995.

expeditiously particularly in heavily populated and commercial areas. PST suggested PHMSA commission an independent analysis to reach a conclusion regarding whether to require these valves.

12. A private citizen suggested that local authorities regularly review incidents in densely populated areas, as self-policing by pipeline operators is insufficient. The commenter also recommended that pipeline construction and modifications be subject to signoff by a licensed professional engineer and be certified for compliance with applicable regulations by a corporate officer subject to criminal penalties, in order to reduce the incentive to cut corners.

13. Northern Natural Gas and a private citizen recommended that the current one-call exemptions for government agencies be eliminated.

Comments Submitted for Questions in Topic H

H.1. Are the spacing requirements for sectionalizing block valves in § 192.179 adequate? If not, why not and what should be the maximum or minimum separation distance? When class locations change as a result of population increases, should additional block valves be required to meet the new class location requirements? Should a more stringent minimum spacing of either remotely or automatically controlled valves be required between compressor stations? Under what conditions should block valves be remotely or automatically controlled? Should there be a limit on the maximum time required for an operator's maintenance crews to reach a block valve site if it is not a remotely or automatically controlled valve? What projected costs and benefits would result from a requirement for increased placement of block valves?

1. AGA and a number of pipeline operators contended that the existing requirements in § 192.179 are adequate. AGA noted that studies have shown there is no safety benefit to having more remote or automatic valves and operators should be permitted to determine the need for additional valves and spacing. AGA contended that there is no safety reason to change the existing regulation and argued that remote or automatic valves should not be mandated for any specific set of circumstances, since they are only one option for pipeline shutdown.

2. Texas Pipeline Association and Texas Oil & Gas Association commented that spacing requirements for natural gas transmission lines have been shown to be adequate for emergency situations. Both associations observed that block valves are not in place to prevent accidents and that the greatest impact of an accident is from the initial gas release, before automatic or remote valves could actuate. The associations also noted that the addition of more block valves would increase the risk to aboveground infrastructure.

3. Accufacts contended that the existing spacing requirements are inadequate and noted that valve spacing plays a significant role in the ''isolation blowdown'' time, or the time to depressurize a gas pipeline segment once isolation valves are closed after a rupture. Accufacts also recommended that additional sectionalizing valves be required when class locations change.

4. Iowa Utilities Board (IUB) suggested that ease of access and the time to respond should be factors relevant to a decision as to whether to install automatic or remote valves. IUB noted that the considerations are different for valves in remote areas compared to urban valves.

5. California Public Utilities Board reported that the issue of valve spacing is under review by the State.

6. A private citizen suggested that valves be required at one-mile intervals in densely populated urban areas and that they close automatically in the event of an incident, since the duration of the fire resulting from an incident is directly proportional to the volume of gas between valves. AGA commented that it is not the amount of gas between valves but rather it is the volume between a valve and a rupture that determines the volume released.

7. Wyoming County Pennsylvania's Commissioners suggested that it is necessary to modify separation distances and to establish adequate distances for gathering lines, including in Class 1 areas. The Commissioners acknowledged that the spacing required for Class 3 locations may be more acceptable than the spacing required for Class 1 areas, but noted that it will take longer to reach a block valve with 10 mile spacing in Pennsylvania's Marcellus Shale regions.

8. An anonymous commenter responded that current valve spacing requirements are adequate and suggested that automation be required if it would take 20 to 30 minutes to respond to a mainline valve.

9. AGA, supported by a number of pipeline operators, noted that operators evaluate the need for additional block valves when they become aware of changes in class location.

10. Atmos commented that the need for additional block valves should be evaluated when class locations change, if pipe replacement is needed to comply with the new class locations. Atmos recommended valve installations, if any, should only be required within the replaced pipeline section. Atmos further recommended that automatic or remote valves should not be required between compressor stations due to the risk of false closures and the extensive modifications that would be required.

11. MidAmerican opposed a requirement to install new block valves when a class location changes or to establish more stringent spacing requirements, noting that ASME/ANSI B31.8 provides adequate guidance for block valve considerations. Texas Pipeline Association, Texas Oil & Gas Association, and Northern Natural Gas agreed, noting that the required class location study includes consideration of current spacing as well as other criteria.

12. The Commissioners of Wyoming County Pennsylvania stated that it is imperative that a suitable number of additional block valves be required when population increases and class location changes, arguing that this is necessary to assure adequate public safety measures are in place.

13. An anonymous commenter suggested that new valves should not be required when HCA or class location boundaries change, noting that such changes occur rather frequently.

14. Northern Natural Gas argued that a prescriptive standard for valve spacing may not necessarily provide additional risk reduction, noting that many Class 2 and 3 locations are short pipe segments within an extended Class 1 location.

15. Texas Pipeline Association and Texas Oil & Gas Association noted that more block valves would not decrease the damage from a pipeline accident, noting that PHMSA studies have shown that fatalities and significant property damage occur within 3 minutes of a pipeline rupture while a remotely-operated valve takes 10 minutes to close. This and other studies have shown the only benefit to adding more valves is reducing the amount of gas lost in an accident.

16. Accufacts contended that a more scientific discussion will demonstrate a maximum spacing of eight miles will provide sufficient risk reduction.

17. MidAmerican suggested that block valves should be automatic or remotely-operated only when adequate response times cannot be achieved by operator personnel. When response times are adequate, MidAmerican contended that use of automatic or remote valves should be at the operator's discretion.

18. Northern Natural Gas suggested that the decision to use remote or automatic shut-off valves should be

based on the operator's risk assessment and should be made, by the operator, on a case-by-case basis.

19. Paiute and Southwest Gas argued that operators should have the flexibility to evaluate and determine whether remote or automatic valves would be beneficial. The companies noted that § 192.935 already requires the consideration of additional valves as a preventive and mitigative measure.

20. Accufacts contended that decisions on valve spacing and whether they should be manual, remote, or automatic will be dependent on the time established for first responders to safely enter an actual gas transmission impact zone following rupture. Accufacts noted that California has set a goal of 30 minutes for first response time.

21. A private citizen suggested that automatic shutoff valves should be used in densely populated areas because they provide the most rapid response.

22. The Commissioners of Wyoming County Pennsylvania suggested that standardization is necessary with remotely and automatically controlled shutoffs. The Commissioners contended that the operator needs to employ remote or automatic valves when transmission and gathering lines are routed through areas that are not easily accessible.

23. INGAA noted that § 192.620 requires a one-hour time frame for closing a valve, and contended this is practical for valves that would isolate pipelines in HCAs and consistent with requirements for alternative MAOP in § 192.620. A number of pipeline operators supported INGAA's comments.

24. Atmos suggested that mandating a minimum time to reach a valve site is impractical, because many variables exist in a dynamic state that affect an operator's ability to reach a block valve site.

25. MidAmerican opposed a specified time frame for response to a valve site, noting that operators should respond in an expedient manner without specified time limits.

26. Northern Natural Gas suggested PHMSA consider a two-hour response time for valves in HCA.

27. Texas Pipeline Association and Texas Oil & Gas Association noted that conditions determine how quickly an operator can reach a valve site in the event of an incident and operators make every effort to respond expeditiously when an incident occurs. The associations opposed adoption of a required response time.

28. TransCanada reported its conclusion that having personnel on site within one hour is reasonable for planning purposes. If this cannot be met, TransCanada suggested that possible valve automation should be required.

29. The Commissioners of Wyoming County Pennsylvania reported their conclusion that there would be value in establishing a maximum response time, especially in Class 1 locations where block valves may be 10 miles apart.

30. INGAA and a number of its pipeline operator members noted that studies have shown consistently that there is no value in installing additional block valves or in automating valves. They suggested that it would be more beneficial to apply resources that would be required to comply with any new requirements in this area towards preventing accidents.

31. MidAmerican reported that installing additional block valves would entail significant costs and suggested that increasing the number of valves could cost in excess of $40 million for its pipeline system. Northern Natural Gas agreed that costs could be substantial, without providing a specific estimate for its pipeline system.

32. Paiute and Southwest Gas estimated that costs to install new valves could range from $100,000 to $1 million per installation.

33. An anonymous commenter estimated that retrofitting a 36-inch valve for remote operation would cost approximately $30,000 plus subsequent maintenance costs.

34. Accufacts noted that the San Bruno accident demonstrated that there is a cost associated with not properly spacing, installing or automating valves in high consequence areas.

H.2. Should factors other than class location be considered in specifying required valve spacing?

1. INGAA, AGA, GPTC and several pipeline operators took the position that no new requirements are needed. These associations argued that § 192.179 provides appropriate minimum standards and reported that operators install additional valves in accordance with their integrity management plans or other factors that they consider voluntarily.

2. Paiute and Southwest Gas opined that no additional criteria are needed. They noted that numerous industry studies have shown that there is little or no safety benefit to installing additional automatic or remote valves. They suggested that operators should have the flexibility to determine, based on local circumstances, where additional valves are needed.

3. Atmos suggested that valve accessibility be given more consideration, noting that installing valves in locations that provide improved accessibility could lead to spacing greater than allowed under current regulations. Atmos further suggested that environmental factors such as water crossings and areas prone to flooding should be taken into consideration.

4. MidAmerican opined that additional factors should be considered and pointed to ASME/ANSI B31.8 for examples.

5. Accufacts concluded that additional factors need to be taken into consideration, noting that protection of identified sites in Class 1 and 2 locations will require shorter valve spacing than is currently required by regulations.

6. The California Public Utilities Commission noted that there are numerous factors to be considered that affect response time, and that this issue is under review by the State.

7. The Texas Pipeline Association, Texas Oil & Gas Association, and Commissioners of Wyoming County Pennsylvania suggested that factors other than class location should not be added to the regulations. They noted that class location serves as a surrogate for the level of risk posed by a pipeline.

H.3. Should the regulations be revised to require explicitly that new valves must be installed in the event of a class location change to meet the spacing requirements of § 192.179? What would be the costs and benefits associated with such a change?

1. INGAA and a number of its pipeline operator members opposed applying § 192.179 requirements retroactively to class location changes. INGAA suggested that, rather than absorbing the cost of installing new valves, other preventive and mitigative measures applied through an integrity management plan would produce greater benefits.

2. AGA and a number of its members opposed requiring new valves be installed when class location changes, arguing that no safety benefit will result.

3. Northern Natural Gas expressed its opinion that current regulations are adequate, noting that class location change studies require consideration of block valve spacing.

4. MidAmerican opined that the existing regulations are adequate and noted that ASME/ANSI B31.8 provides other factors for consideration.

5. GPTC expressed its belief that existing requirements are adequate, noting that operators voluntarily consider other factors in establishing valve locations.

6. Atmos suggested that PHMSA not require the installation of new valves

due to changes in class location, but stated the agency should consider the need for additional block valves if pipe replacement is needed as a result of the change.

7. Accufacts suggested that new valves should be required following class location changes, but suggested that a reasonable time should be provided for such valves to be installed and operational.

8. The Texas Pipeline Association and Texas Oil & Gas Association commented that no safety benefit has been demonstrated for the installation of additional valves. The associations suggested that installing additional valves could be counterproductive, since more above-ground valves could pose an additional risk to the public.

9. The California Public Utilities Commission opined that the regulations should require explicitly that additional valves be installed when class location changes, but expressly withheld an opinion on related costs.

10. A private citizen suggested that all requirements related to class location should apply when class location changes, unless PHMSA adopts an expanded definition for HCA to replace class location considerations.

11. An anonymous commenter stated that most operators anticipate changes to Class 3 or 4 when pipelines are designed and constructed. The commenter estimated that installing a new 36-inch valve would cost $70 to $100 thousand, not including down time and lost product.

12. The Commissioners of Wyoming County Pennsylvania commented that the regulations need to be revised to explicitly require that new valves be installed when class locations change. The Commissioners suggested that this needs to extend to both transmission and gathering lines in Class 1 areas.

H.4. Should the regulations require addition of valves to existing pipelines under conditions other than a change in class location?

1. INGAA and a number of pipeline operators noted that studies have indicated valve spacing has limited impact on the duration of an incident. INGAA suggested that a performance-based approach to incident mitigation management would better inform valve placement.

2. AGA opposed requiring additional valves under any scenario. A number of pipeline operators supported AGA's comments.

3. Accufacts suggested that new valves should be installed when a site becomes an HCA regardless of class location, but a reasonable time should be allowed for such valves to be installed and become operational.

4. Ameren Illinois opposed requiring new valves under other conditions, opining that existing requirements are adequate.

5. GPTC and Atmos commented that existing regulations are a sufficient baseline for determining valve location, noting that operators often use more stringent spacing criteria during initial construction.

6. MidAmerican opposed requiring that installation of new valves on existing pipelines for any reason other than a class location change, noting that ASME/ANSI B31.8 provides additional factors for operators to consider in determining valve location.

7. Northern Natural Gas noted that existing regulations require that operators consider additional valves as a preventive and mitigative measure and expressed its conclusion that this requirement is sufficient.

8. Paiute and Southwest Gas suggested that operators should have the flexibility to evaluate and determine where remotely-controlled or automatic valves would be beneficial. The companies noted that § 192.935 requires the consideration of additional valves as a preventive and mitigative measure and industry studies indicate little or no safety benefit to installing additional valves.

9. The California Public Utilities Commission suggested that conditions that would impede access to a valve may need to be considered in determining valve placement.

H.5. What percentage of current sectionalizing block valves are remotely operable? What percentage operate automatically in the event of a significant pressure reduction?

1. INGAA estimated that 40 to 50 percent of mainline block valves are remotely-operated or automatic. INGAA did not provide an estimate specifically for automatic valves. INGAA noted that application of Incident Mitigation Management would lead operators to conclusions as to whether a valve should be remote or automatic. A number of pipeline operators supported INGAA's comments.

2. AGA and GPTC reported that they have no data with which to respond to this question.

3. Ameren Illinois reported that it has no remotely-controlled valves.

4. Atmos reported that remote and automatic valves are not installed routinely. Remotely-controlled valves are installed on a small number of select pipelines, representing approximately 0.1 percent of all valves.

5. Kern River reported that 66 percent of its mainline block valves, and all block valves in HCA, are remotely-controlled.

6. MidAmerican reported that less than one percent of its valves are remotely-controlled and a similarly small percentage of them are automatic.

7. Northern Natural Gas reported that remotely-controlled valves are located only at compressor stations on its pipeline system.

8. Paiute reported that less than 10 percent of the valves on its system are remotely-controlled. Paiute has no automatic valves.

9. Southwest Gas reported that it has no remotely-controlled or automatic valves, due to the urban nature of its pipeline system.

10. Texas Pipeline Association reported that a limited survey of its members indicated the number of remotely-controlled valves varies from 1 to 18 percent; the number of automatic valves varies from zero to 18 percent.

H.6. Should PHMSA consider a requirement for all sectionalizing block valves to be capable of being controlled remotely?

1. INGAA and a number of pipeline operators opposed consideration of such a requirement. They commented that no one solution should be mandated and Incident Mitigation Management should guide operators to decisions as to which valves should be remote or automatic.

2. AGA and a number of pipeline operators also opposed consideration of such a requirement, noting remotely-controlled valves are only one option for shutting down a pipeline.

3. Accufacts opposed such a generic requirement, noting small-diameter gas transmission pipelines may not merit automation because of the science of pipeline diameter rupture associated with high heat flux releases.

4. GPTC opined that remotely-controlled valves do not improve safety, thus there is no basis for requiring their use. GPTC noted that operators voluntarily consider many factors in establishing valve locations.

5. Atmos opposed consideration of this requirement, noting there are issues with false closures and the costs of conversion or installation are extensive. Atmos also noted that industry studies have shown no increase in safety from having more remotely-controlled or automatic valves.

6. Kern River opined that this should be an operator decision, noting that integrity management regulations require the consideration of remote or automatic valves as part of identifying preventive and mitigative measures.

7. MidAmerican strongly opposed requiring all sectionalizing block valves to be remotely controlled. MidAmerican stated that the location and type of valve should be based on an engineering assessment. A requirement that all valves be remote would increase costs and may provide disincentives to installation of additional valves.

8. Northern Natural Gas opposed such a requirement, commenting this should be a case-by-case decision based on risk reduction.

9. Paiute and Southwest Gas reported their conclusion that the existing requirements in § 192.179 are adequate. The companies recommended that operators have the flexibility to evaluate and determine where remote or automatic valves would be beneficial. They noted that § 192.935 requires the consideration of additional valves as a preventive and mitigative measure and industry studies indicate little or no safety benefit to installing additional remote or automatic valves.

10. The Texas Pipeline Association and Texas Oil & Gas Association opposed consideration of a requirement that all block valves be remotely-operable. The associations noted that it would be tremendously expensive to do so, and it would require power and communication sources that may not be readily available at valve sites.

11. The California Public Utilities Commission commented that this could be impractical for distribution systems considering space limitations and the practicability of supplying communication facilities for valves. This issue is under review by the State for transmission facilities.

12. The Iowa Utilities Board noted that remotely-operated valves require a SCADA or other type of remote monitoring and operating system. A requirement that all sectionalizing valves be remotely-operable would thus be a de facto requirement that all operators, regardless of size or the potential consequences of an accident, install a SCADA system. Small operators and municipal utilities in Iowa do not have such systems.

13. The Commissioners of Wyoming County Pennsylvania commented that it might be desirable for all valves to be remotely-operable or automatic, but PHMSA must consider what is reasonable and adequate.

14. An anonymous commenter opposed consideration of a requirement that all valves be remotely-operable, noting that most gas pipeline accident consequences occur immediately upon release, before a remote valve could have any effect.

H.7. Should PHMSA strengthen existing requirements by adding prescriptive decision criteria for operator evaluation of additional valves, remote closure, and/or valve automation? Should PHMSA set specific guidelines for valve locations in or around HCAs? If so, what should they be?

1. INGAA and a number of pipeline operators opposed PHMSA's establishment of prescriptive criteria, suggesting instead that PHMSA develop guidance for Incident Mitigation Management.

2. AGA, GPTC, and a number of pipeline operators commented that requirements in § 192.179 are adequate. AGA noted that operators already consider additional valves in their emergency response portfolio and install them where economically, technically, and operationally feasible. Some operators noted that numerous industry studies indicate that there is little or no safety benefit to installing additional remote or automatic valves and § 192.935 already requires the consideration of additional valves as a preventive and mitigative measure.

3. Accufacts supported the consideration of prescriptive criteria, arguing that prescriptive regulation should be mandated for certain gas transmission pipelines in HCAs, especially larger-diameter pipelines in certain areas where manual closure times can be long.

4. Ameren Illinois opposed additional prescriptive criteria, arguing that existing requirements are sufficient and that additional valves should be considered when economically, technically, and operationally feasible to address specific safety concerns.

5. California Public Utilities Commission expressed its conclusion that prescriptive decision criteria may need to be added for all Method 1 HCA locations.

6. The Iowa Utilities Board, the Texas Pipeline Association and the Texas Oil & Gas Association questioned whether it is possible to write prescriptive decision criteria that can reasonably address all possible situations and circumstances or always provide the best option. These commenters suggested that operator judgment and discretion should play a part in these decisions.

7. MidAmerican expressed its belief that pipeline safety would not be enhanced by additional prescriptive criteria and opposed specific requirements for valve location near HCAs, noting that ASME/ANSI B31.8 provides considerations for operators to take into account when deciding on valve locations.

8. An anonymous commenter suggested that prescriptive criteria could be useful in assuring a degree of consistency among pipeline operators.

H.8. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to the commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

Response to Topic H Comments

PHMSA appreciates the information provided by the commenters. Based on the investigation of the San Bruno incident, the NTSB recommended (P–11–11) that PHMSA promulgate regulations to explicitly require that automatic shutoff valves or remote control valves in high consequence areas and in Class 3 and 4 locations be installed and spaced at intervals considering the population factors listed in the regulations. In addition, Section 4 of the Act requires issuance of regulations on the use of automatic or remote-controlled shut-off valves, or equivalent technology, if appropriate, and where economically, technically, and operationally feasible. The Act also requires the Comptroller General of the United States to complete a study on the ability of transmission pipeline facility operators to respond to a hazardous liquid or gas release from a pipeline segment located in a high-consequence area. On March 27, 2012, PHMSA sponsored a public workshop to seek stakeholder input on this issue. On October 5, 2012, PHMSA also briefed stakeholders, via a webcast, on the status of an ongoing study conducted by Oak Ridge National Laboratory on understanding the application of automatic control and remote control shutoff valves. The final study was published in December 2012. PHMSA also included this topic in the July 18, 2012 Pipeline Research Forum. PHMSA will take further action on this topic after completion of the assessment of the findings from these activities. PHMSA will consider the comments

received on the ANPRM and will consider this topic in future rulemaking, as required.

I. Corrosion Control

Gas transmission pipelines are generally constructed of steel pipe, and corrosion is a potential threat. Subpart I of part 192 addresses the requirements for corrosion control of gas transmission pipelines, including the requirements related to external corrosion, internal corrosion, and atmospheric corrosion. However, this subpart does not include requirements for the specific threat of Stress Corrosion Cracking (SCC). The ANPRM requested comments regarding revisions to subpart I to improve the specificity of existing requirements and to add requirements relative to SCC.

Existing requirements have proven effective in reducing the occurrence of incidents caused by external corrosion. Many of the provisions in subpart I, however, are general in nature. In addition, the current regulations do not include provisions that address issues that experience has shown are important to protecting pipelines from corrosion damage, including:

- Post-construction surveys for coating damage.
- Post-construction close interval survey (CIS) to assess the adequacy of cathodic protection (CP) and inform the location of CP test stations.
- Periodic interference current surveys to detect and address electrical currents that could reduce the effectiveness of CP.
- Periodic use of cleaning pigs or sampling of accumulated liquids to assure that internal corrosion is not occurring.

Corrosion control regulations applicable to gas transmission pipelines currently do not include requirements relative to SCC. SCC is cracking induced from the combined influence of tensile stress and a corrosive medium. SCC has caused numerous pipeline failures on hazardous liquids pipelines, including a 2003 failure on a Kinder Morgan pipeline in Arizona, a 2004 failure on an Explorer Pipeline Company pipeline in Oklahoma, a 2005 failure on an Enterprise Products Operating line in Missouri, and a 2008 failure on an Oneok NGL Pipeline in Iowa. More effective methods of preventing, detecting, assessing and remediating SCC in pipelines are important to making further reductions in pipeline failures.

The ANPRM then listed questions for consideration and comment. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comments for Topic I

1. AGA opined that the questions posed under this topic are unclear and disjointed and do not differentiate between distribution and transmission pipelines. In addition, AGA stated that PHMSA did not provide a rationale for why there is any concern over subpart I. A number of pipeline operators supported AGA's comments.

2. MidAmerican noted that PHMSA says current requirements are adequate yet goes on to propose new requirements.

3. INGAA reported that its members commit to mitigating corrosion anomalies in accordance with ASME/ANSI B31.8S, both inside and outside HCAs. INGAA argued that enhanced external corrosion management methods, such as close interval surveys and post-construction coating surveys, should not be required singularly and arbitrarily by new prescriptive regulations, since these methods can be redundant or inferior when combined with other assessment techniques. INGAA argued that these methods should continue to be used by operators on a threat-specific basis, as is currently practiced under performance-based regulations and consensus-based IM programs. A number of pipeline operators supported INGAA's comments.

4. Chevron argued that more prescriptive requirements are unnecessary, noting that current regulations allow operators the flexibility to select the most effective corrosion control method for the specific corrosion threats to a pipeline segment.

5. MidAmerican reported that it has never identified internal corrosion on its pipeline system and prescriptive requirements related to that threat would divert resources. MidAmerican opined that subpart I provides an adequate level of safety and any changes in that subpart should be approached carefully because they could be beneficial or detrimental for reducing risk. MidAmerican further noted that NACE SP0204 and ASME/ANSI B31.8S provide adequate guidance in this area.

6. TransCanada suggested that PHMSA incorporate the new SCC management provision in ASME/ANSI B31.8S as the basis for identifying and mitigating SCC and be responsive to further enhancements. TransCanada also suggested that the best way to manage corrosion anomalies is through assessments.

7. Dominion East Ohio opined that existing regulations in this area are adequate.

8. NAPSR urged PHMSA to establish or adopt standards or procedures, through a rulemaking proceeding, for improving the methods of preventing, detecting, assessing, and remediating stress corrosion cracking. NAPSR also suggested that PHMSA consider additional requirements to perform periodic coating surveys at compressor discharges and other high-temperature areas potentially susceptible to SCC and develop a training module for pipeline operators and federal and state inspectors that would include the identification of potential areas of SCC, detecting, assessing and remediating SCC.

9. A private citizen reported that his analysis of data from over 5000 lightning strikes indicates that cathodic protection systems make pipelines a frequent target for lightning.

10. A private citizen suggested that enforcement of cathodic protection requirements be strengthened, stating that the number of enforcement actions indicates that operators are not operating or maintaining CP as required.

11. A private citizen suggested that in-line inspection (ILI) capable of detecting seam issues should be required for pipe susceptible to selective seam weld corrosion, since pressure testing is not adequate to detect non-leak anomalies. If not possible, the commenter would require that this pipe be replaced.

Response

PHMSA appreciates the information provided by the commenters. In light of the contributing factors to the San Bruno incident, including PG&E's reliance on direct assessment under circumstances for which direct assessment was not effective, and the incident in Marshall, Michigan, where fracture features were consistent with stress corrosion cracking, PHMSA believes that more specific measures are needed to address both stress corrosion cracking and selective seam weld corrosion. Based on lessons learned from incident investigations, such as the 2012 incident in Sissonville, West Virginia and the 2007 incident in Delhi, Louisiana, and improved capabilities of corrosion evaluation tools and methods, PHMSA believes that more specific minimum requirements are needed for control of both internal and external corrosion. In addition, cathodic protection is a well-established corrosion control tool, and PHMSA believes the benefits of cathodic protection outweigh any potential risks. Therefore, PHMSA proposes several

enhancements to subpart I for corrosion control and subparts M and O for assessment, including specific requirements to address stress corrosion cracking and selective seam weld corrosion, and enhanced corrosion control measures for HCAs, which are discussed in more detail in response to specific questions, below.

Comments Submitted for Questions in Topic I

I.1. Should PHMSA revise subpart I to provide additional specificity to requirements that are now presented in general terms? If so, which sections should be revised? What standards exist from which to draw more specific requirements?

1. INGAA and a number of pipeline operators commented that adding prescriptive requirements would be disruptive to operators, noting PHMSA has acknowledged the effectiveness of performance-based elements of the current requirements.

2. The AGA, the GPTC, the Texas Pipeline Association, the Texas Oil & Gas Association, and numerous pipeline operators questioned the need to amend subpart I. AGA noted that this is one of the more prescriptive sections of the code and has a 40-year history of demonstrated effectiveness.

3. Ameren Illinois opined it is not necessary to revise subpart I, because integrity management regulations require operators to identify threats and to manage them.

4. MidAmerican opposed more specific requirements for corrosion control, noting that there is wide diversity among pipelines and it is unlikely that a single set of specific requirements would apply effectively to all pipelines. MidAmerican suggested that additional specific requirements must be tailored to a wide range of pipeline configurations to be of any value.

5. Northern Natural Gas reported that IM results demonstrate that corrosion has been adequately addressed on its pipeline system.

6. Paiute and Southwest Gas noted that subpart I is one of the most prescriptive sections of the code, subpart O provides an additional layer of regulation, and NACE standards are robust and incorporated by reference.

7. Panhandle Energy commented that existing performance based regulations require the pipeline operator to establish procedures to determine the adequacy of CP monitoring locations and appropriate remediation schedules based on circumstances that are unique to each pipeline. Panhandle observed that PHMSA appears to be attempting to establish ''One Size Fits All'' prescriptive requirements and opined that such changes would have no positive effect on safety and may be detrimental.

8. Accufacts observed that too many pipeline operators are assuming that IM assessments can replace subpart I requirements when the intent was that the regulations work in conjunction with one another. Accufacts suggested that prescriptive regulation is needed to avoid serious misapplication of the IM section and to assure that subpart I regulations are implemented to keep corrosion under control.

9. Panhandle observed that the ANPRM states that ''prompt'' as used in § 192.465(d) is not defined, and does not recognize the definition of ''prompt remedial action'' outlined in the 1989 Office of Pipeline Safety's Operation and Enforcement Manual. Panhandle noted that the enforcement guidance requires PHMSA to evaluate the circumstances and provide rationale for any determination of ''unreasonable delay'' in any enforcement action associated with § 192.465(d). Panhandle observed that such evaluations are inherent in the enforcement of performance-based regulations and stand in sharp contrast to the ''check-box'' enforcement mentality of prescriptive regulations. Panhandle complained that the language of the ANPRM contradicts more than 20 years of enforcement history. Panhandle interpreted the ANPRM to mean that PHMSA has no authority to interpret part 192 other than through rulemaking.

10. An anonymous commenter suggested that PHMSA delete the requirement regarding 300 mV pipe-to-soil reading shift and adopt NACE SP0169.

11. The California Public Utilities Commission suggested that PHMSA consider modifying acceptance criteria to be based on instant-off readings, arguing that this would provide improved specificity concerning IR drop.

Response to Question I.1 Comments

PHMSA appreciates the information provided by the commenters. The majority of industry comments do not support revising subpart I to provide additional specificity to requirements. However, for the reasons discussed in this NPRM, PHMSA believes that certain regulations can be improved to better address issues that experience has shown can be important to protecting pipelines from corrosion damage, and that prudent operators currently implement. Therefore, PHMSA proposes to amend subparts G and I to: (1) Enhance requirements for electrical surveys (*i.e.,* close interval surveys); (2) require post construction surveys for coating damage; (3) require interference current surveys; (4) add more explicit requirements for internal corrosion control; and (5) revise Appendix D to better align with the criteria for cathodic protection in NACE SP0169. Included in these changes is a new definition of the terms ''electrical survey'' and ''close interval survey.'' To conform to the revised definition of ''electrical survey,'' the use of that term in subpart O would be replaced with ''indirect assessment'' to accommodate other techniques in addition to close-interval surveys.

I.2. Should PHMSA prescribe additional requirements for post-construction surveys for coating damage or to determine the adequacy of CP? If so, what factors should be addressed e.g., pipeline operating temperatures, coating types, etc.)?

1. INGAA and a number of pipeline operators argued that post-construction surveys are of limited use, arguing that they can identify damaged coating but not necessarily areas where SCC can occur.

2. AGA, supported by a number of its pipeline operator members, opined that existing requirements for post-construction surveys for coating damage and cathodic protection are sufficient and operators need flexibility to apply their resources to the highest risk areas.

3. GPTC agreed that existing regulations are sufficient, noting that operators are not experiencing difficulties related to post-construction surveys for coating damage or for determining the adequacy of CP.

4. Ameren Illinois noted that part 192 requirements are followed for the installation of new coated steel pipe and it will develop a process to deal with any problems that may be identified through integrity management. Atmos agreed, noting that post-construction baseline surveys are typically performed.

5. Kern River opined that corrosion control measures and mitigation are site specific and therefore universal conditions and mitigation requirements would likely be ineffective and inefficient. Performance-based criteria are the best way to ensure the integrity of the pipeline with the most innovative and effective solutions.

6. MidAmerican opposed new requirements, noting that areas of coating damage on pipelines are protected from corrosion by cathodic protection and existing requirements are adequate in this area.

7. NACE concluded that current regulations have proven adequate and

noted that PHMSA acknowledges in the ANPRM that ''[T]hese requirements have proven effective in minimizing the occurrence of incidents caused by gas transmission pipeline corrosion.''

8. Paiute and Southwest Gas opined that current requirements for coatings (§ 192.461) and cathodic protection (§ 192.463) are sufficient.

9. Northern Natural Gas stated that no new requirements are needed, observing that it takes action when CP surveys indicate a concern.

10. Panhandle argued that the proposed requirement for post construction coating does not address the cause of coating damage during construction and INGAA best practices have proven to be an effective means to provide pipeline safety, affording flexibility and recognizing the inherent limitations of coating surveys. Panhandle observed that PHMSA's requirements for the investigation of anomalies found during post construction coating surveys on alternate MAOP lines are overly conservative, waste resources, do not enhance pipeline safety, and should not be considered for use in any proposed rulemaking. Panhandle further recommended that any proposed regulations related to pipeline temperature should not use the 120 degrees Fahrenheit value used in § 192.620, since studies have demonstrated pipeline coatings can withstand temperatures up to 150 degrees. Panhandle further argued that industry experience verifies that the vast majority of coating holidays associated with pipeline construction are not an integrity threat when cathodic protection is applied to the pipeline. It also suggested that verification of pipeline integrity through ILI or pressure testing better utilizes resources than excavation and repair of pinholes in pipeline coating systems.

11. Panhandle observed that, from its experience with over 900 completed excavations, the coating anomaly ranking system of NACE SP0502 is extremely conservative and should only be used as part of the ECDA process.

12. Texas Pipeline Association and Texas Oil & Gas Association suggested that PHMSA should consider requiring close interval surveys at 5-year intervals.

13. TransCanada noted that enhanced external corrosion management methods, such as close interval surveys and post construction coating surveys, have proven effective in helping identify and mitigate certain corrosion damage conditions. TransCanada argued, however, that these methods should not be required singularly and arbitrarily by new prescriptive requirements, as they can be redundant or inferior when combined with other assessment techniques.

14. Pipeline Safety Trust suggested that additional post-construction surveying should be required to identify damage to or weakness in coating and to ensure the integrity of CP.

15. An anonymous commenter suggested that PHMSA require close interval survey before energizing new CP components, after backfill has settled, noting that this would ensure test stations are located in areas that will assure adequate protection.

16. The Commissioners of Wyoming County Pennsylvania recommended that PHMSA review operator practices and codify the ''best practices'' in this area.

Response to Question I.2 Comments

PHMSA appreciates the information provided by the commenters. The majority of industry comments do not support revising subpart I to prescribe additional requirements for post-construction surveys for coating damage or to determine the adequacy of CP. However, as detailed in the ANPRM, experience has shown that construction activities can damage coating and that identifying and remediating this damage can help protect pipeline integrity. PHMSA does agree that prescriptive practices for conducting coating surveys, as well as the criteria for remediation and other responses to indications of coating damage, are not always appropriate because coating damage is case-specific. Therefore, PHMSA proposes to add a requirement that each coating be assessed to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG) and damage be remediated if damage is discovered. In addition, for HCA segments, PHMSA proposes enhanced preventive and mitigative measures and repair criteria for repair of coating with a voltage drop classified as moderate or severe.

I.3. Should PHMSA require periodic interference current surveys? If so, to which pipelines should this requirement apply and what acceptance criteria should be used?

1. INGAA and a number of pipeline operators recommended that PHMSA not establish new requirements in this area without discussing the topic with operators first. INGAA pointed out that guidance already exists in the form of Advisory Bulletin ADB–03–06 and NACE SP0169.

2. Kern River opposed new requirements for periodic surveys, arguing that §§ 192.465, 192.467, and 192.473 adequately address the concerns.

3. Ameren Illinois also opposed new requirements. Ameren reported that it conducts testing annually at sites where stray currents are expected and noted that integrity management regulations already require operators to identify and address threats.

4. NACE International suggested that current regulations are adequate and have served the public interest. NACE noted operators are currently taking action to identify interference currents and protect their pipelines, and it has provided guidance through standards and technical papers.

5. Atmos noted that interference surveys would be a part of an investigation into cathodic protection systems that do not provide minimum levels of protection. Operators are already required to maintain minimum levels of protection.

6. Northern Natural Gas reported that it conducts additional surveys when issues are discovered during periodic maintenance, when new foreign line crossing are installed, or for new construction, but opposed new requirements in this area.

7. Paiute and Southwest Gas opposed new requirements, noting that operators should have the flexibility to allocate their resources in a manner that best suits their system.

8. Panhandle opposed new requirements, noting that existing performance-based regulations have proven adequate to address the threat of stray currents. Panhandle commented that the gas pipeline industry recognized and reacted to the threat of AC interference decades prior to the ANPRM, and suggested that the lack of justification from PHMSA on this issue is a strong indicator that industry has reacted appropriately to integrity threats in accordance with the requirements of § 192.473. Panhandle noted that interference currents have been addressed in several industry standards and publications. In particular, Section 9, *Control of Interference Currents,* of NACE SP0169, *Control of External Corrosion on Underground of Submerged Metallic Piping Systems,* provides guidance for the detection and mitigation of interference currents.

9. Texas Pipeline Association and Texas Oil & Gas Association stated that current regulations are sufficient; however, if new regulations are promulgated, the associations recommended that PHMSA use the liquid pipeline requirement for periodic interference surveys and be applicable only to foreign line crossings and

pipelines near large DC-powered equipment.

10. An anonymous commenter stated that new regulations are not needed, as most operators will conduct surveys on their own, generally when pipe-to-soil readings drop.

Response to Question I.3 Comments

PHMSA appreciates the information provided by the commenters. Industry comments do not support revising subpart I to require periodic interference current surveys. However, as detailed in the ANPRM, pipelines are often routed near, in parallel with, or in common rights-of-way with, electrical transmission lines or other pipelines that can induce interference currents, which, in turn, can induce corrosion. Recent incidents on pipelines operated by Kern River and Center Point are examples of incidents this requirement seeks to prevent. Section 192.473 currently requires that operators of pipelines subject to stray currents have a program to minimize detrimental effects but does not require surveys, mitigation, or provide any criteria for determining the adequacy of such programs. Therefore, PHMSA proposes to add a requirement that the continuing program to minimize the detrimental effects of stray currents must include: (1) Interference surveys to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected; (2) analysis of the results of the survey; and (3) prompt remediation of problems after completing the survey to protect the pipeline segment from deleterious current. For HCA segments, PHMSA proposes to address this in enhanced preventive and mitigative measures, and to include performance criteria.

I.4. Should PHMSA require additional measures to prevent internal corrosion in gas transmission pipelines? If so, what measures should be required?

1. INGAA, AGA, GPTC, and numerous pipeline operators contended that existing requirements are adequate to manage internal corrosion. INGAA noted that subparts I and O include requirements for controlling internal corrosion and assessments are being performed on almost all gas transmission lines. INGAA further commented that controlling gas quality is most important.

2. Ameren Illinois opposed new requirements addressing internal corrosion, noting that § 192.475 addresses the topic and subpart O requires operators to respond to risks that are identified.

3. Kern River and Northern Natural Gas opposed new requirements, noting that industry data show IC is a minor threat to natural gas transmission pipelines. Kern River commented that ASME/ANSI B31.8S, Appendix A2, covers the analysis of gas constituents. Northern monitors gas quality and takes corrective action as needed.

4. MidAmerican opposed new requirements, commenting that internal corrosion is a regional problem and does not occur in many areas of the country. MidAmerican requested that current integrity management regulations be revised to eliminate the need to conduct internal corrosion direct assessment when internal corrosion is not a threat.

5. NACE International opined that current regulations in subpart I are adequate to address internal corrosion, and PHMSA's proposed prescriptive requirements are not feasible.

6. Panhandle observed that requirements to minimize the potential for internal corrosion in gas transmission pipelines are included in §§ 192.475, 192.476, and 192.477. In addition, OPS issued ADB–00–02 requiring pipeline operators to review their internal corrosion monitoring programs and operation. IM regulations in subpart O require integrity management assessments that address the threat of internal corrosion. INGAA members report that completion of baseline assessments required by subpart O will result in the assessment of more than half of the gas transmission pipeline mileage in the U.S. Panhandle commented that several proposed prescriptive internal corrosion requirements provided in the ANPRM are not feasible and noted that liquids tend to accumulate in low spots that typically are not accessible for sampling. Panhandle opined that vigilant enforcement of gas quality standards is the most essential component of an internal corrosion control program.

7. Texas Pipeline Association and Texas Oil & Gas Association argued that no benefit would be gained by additional requirements in this area. The associations observed that internal corrosion threats are highly localized and monitoring and remediation efforts must be customized for local conditions.

8. IUB noted that not all pipelines are susceptible to internal corrosion and commented that operators and state inspection personnel should not be unduly burdened by additional measures when problems do not exist.

9. An anonymous commenter suggested that PHMSA require each operator to have a subject matter expert well qualified in internal corrosion, arguing that most operators currently rely on third-party contractors.

Response to Question I.4 Comments

PHMSA appreciates the information provided by the commenters. The majority of industry comments do not support revising subpart I to require additional measures to prevent internal corrosion in gas transmission pipelines. However, the current requirements for internal corrosion control are non-specific and PHMSA believes that there is benefit in enhancing the current internal corrosion control requirements to establish a more effective minimum standard for internal corrosion management. Therefore, PHMSA proposes to add a requirement that each operator develop and implement a program to monitor for and mitigate the presence of, deleterious gas stream constituents and that the program be reviewed at least semi-annually. For HCA segments, PHMSA proposes to address this in enhanced preventive and mitigative measures to include objective performance criteria.

I.5. Should PHMSA prescribe practices or standards that address prevention, detection, assessment, and remediation of SCC on gas transmission pipeline systems? Should PHMSA require additional surveys or shorter IM survey internals based upon the pipeline operating temperatures and coating types?

1. INGAA and a number of pipeline operators recommended that PHMSA avoid prescriptive requirements for the prevention, detection, assessment, and remediation of SCC. The commenters noted that SCC varies from pipeline to pipeline and suggested that threat management should be through a framework of processes and decision making that can tailor threat management to the requirements of each pipeline.

2. AGA and a number of its pipeline operators also objected to new requirements in this area, noting that numerous industry documents exist that provide guidance to address SCC.

3. Panhandle suggested that PHMSA avoid prescriptive standards for the prevention, detection, assessment, and remediation of SCC on gas transmission systems given the complex and variable nature of the factors contributing to the formation and growth of SCC, arguing performance-based standards allow operators the maximum flexibility to develop and apply situational techniques for detecting, assessing, and remediating this threat. Panhandle noted that multiple standards and publications are available to address internal corrosion and that the Pipeline

Research Council International (PRCI) has ongoing research in this area. Panhandle expressed the view that voluntary use of performance based standards, allowing operator flexibility in detecting, assessing and remediating this threat, will ensure that the methods used in managing these types of anomalies continue to improve.

4. GPTC, Ameren Illinois, Atmos, Paiute, and Southwest Gas argued that existing regulations are sufficient and noted that there are numerous industry documents that provide additional guidance for addressing SCC.

5. TransCanada suggested that PHMSA adopt the current version of ASME/ANSI B31.8S.

6. The Commissioners of Wyoming County Pennsylvania opined that it is reasonable for PHMSA to prescribe practices or standards that address prevention, detection, assessment and remediation of SCC on transmission and gas gathering lines, including those in Class 1 locations. The Commissioners argued that it is important to address this aspect of corrosion given aging of existing pipelines and the significant number of new pipelines.

7. Air Products and Chemicals argued that operators should not be required to undertake SCC prevention, detection, assessment and remediation activities where a pipeline does not meet the B31.8S criterion for SCC. Air Products further commented that it is important that PHMSA's regulations and standards reflect the threshold concept of susceptibility to SCC, and that a pipeline that does not meet the B31.8S criteria for SCC risk should not be required to undertake SCC prevention, detection, assessment, and remediation activities.

8. NACE International stated that overly prescriptive rules can supplant sound engineering judgment and prevent innovation and the development of new technologies.

9. Northern Natural Gas argued that the current regulations and industry standards provide adequate guidance and that the assessment criteria address operating temperature and coating type. Northern Natural Gas noted that operating temperature is addressed in PHMSA Gas FAQ 223 and that the reassessment interval should be determined by the results of the integrity assessment performed pursuant to ASME B31.8S.

10. MidAmerican pointed out that these concerns are addressed in the pre-assessment phase of direct assessment and adequately covered in ASME/ANSI B31.8S.

11. Texas Pipeline Association and Texas Oil & Gas Association suggested that additional regulations related to SCC could prove beneficial. At the same time, the associations recommended that PHMSA not require additional surveys or shorter intervals, arguing that the current regulations are based on sound engineering practices.

12. A private citizen commented that SCC should be addressed as part of a comprehensive corrosion control program.

13. An anonymous commenter noted that a reliable survey technique for SCC does not now exist and suggested that PHMSA require shorter assessment intervals for pipelines with a history of SCC.

14. INGAA argued that pipe temperature and coating are not sufficient to identify SCC. INGAA contended that ASME/ANSI B31.8S adequately covers prevention, detection, assessments, and remediation of SCC and criteria to capture all pipe potentially susceptible to SCC would be overly conservative. A number of pipeline operators supported INGAA's comments.

15. NACE International opined that there are too many factors involved, and they are too interrelated and location-specific, to allow prescribing an optimal assessment interval for SCC.

Response to Question I.5 Comments

PHMSA appreciates the information provided by the commenters. The majority of industry comments do not support new requirements for the prevention, detection, assessment, and remediation of SCC. PHMSA recognizes that SCC is an important safety concern, but does not believe the current methods for managing SCC anomalies supports prescribing a detailed SCC management approach that would be effective for all operators. PHMSA does not propose to amend subpart I to prescribe an SCC management plan at this time. PHMSA will continue to study this issue and support ongoing research. PHMSA plans to hold a public forum on the development of SCC standards in the future. Once that process is complete, PHMSA will consider new minimum safety standards for managing the threat of SCC. However, under topics C and G, above, PHMSA does propose to include more specific requirements for conducting integrity assessments for the threat of SCC and for enhancing the HCA and non-HCA repair criteria to address SCC.

I.6. Does the NACE SP0204–2008 (formerly RP0204) Standard ''Stress Corrosion Cracking Direct Assessment Methodology'' address the full life cycle concerns associated with SCC? Should PHMSA consider this, or any other standards to govern the SCC assessment and remediation procedures? Do these standards vary significantly from existing practices associated with SCC assessments?

1. INGAA and a number of pipeline operators stated that NACE SP0204 does not address the full life cycle of concerns of SCC. INGAA added that SP0204, along with ASME/ANSI B31.8S, NACE publication 35103, STP–TP–011, and Canadian recommended practices, do cover the full life cycle concerns.

2. NACE International reported that its standard (SP0204) does not address the full life cycle concerns of SCC.

3. GPTC noted that existing regulations and standards address SCC concerns and commented that it is not clear what is meant by ''full life cycle concerns.''

4. Ameren Illinois argued that full life cycle concerns are addressed in the pre-assessment phase of stress corrosion cracking direct assessment (SCCDA) and new prescriptive requirements are not needed.

5. Northern Natural Gas commented that ASME/ANSI B31.8S should be used in conjunction with NACE SP0204.

6. Panhandle reported that SCCDA was never intended to address full life cycle management for SCC. The standard does not address aspects such as the formation or nucleation of cracks or calculations to assess the severity of cracks. Panhandle opined that the collective body of SCC research does address the full life cycle, but cautioned the full body of knowledge of all documents must be considered as some may be dated and do not reflect current knowledge on SCC management.

7. An anonymous commenter suggested that NACE SP0204 does not address full life cycle concerns, noting that SCC has been found in circumstances where the standard would suggest it should not be expected.

Response to Question I.6 Comments

PHMSA appreciates the information provided by the commenters and agrees that sufficient information is not available at this time to specify prescriptive standards for SCC management. See the response to comments received on question I.5.

I.7. Are there statistics available on the extent to which the application of the NACE Standard, or other standards, have affected the number of SCC indications operators have detected on their pipelines and the number of SCC-related pipeline failures? Are statistics available that identify the number of SCC occurrences that have been

discovered at locations that meet the screening criteria in the NACE standard and at locations that do not meet the screening criteria?

1. INGAA, GPTC, Texas Pipeline Association, Texas Oil & Gas Association, and numerous pipeline operators reported that no data has been collected on the application of any current standard. INGAA added that available statistics indicate that the annual number of failures due to SCC is generally decreasing and noted that a high percentage of in-service failures, failures during hydro testing, and instances where SCC cracks greater than 10 percent were found during excavations have met the screening criteria of ASME/ANSI B31.8S (which are identical to the NACE criteria).

2. Northern Natural Gas reported that it has found one instance of SCC and no segments were identified subject to similar circumstances.

Response to Question I.7 Comments

PHMSA appreciates the information provided by the commenters and agrees that sufficient information is not available at this time to specify prescriptive standards for SCC management. PHMSA will be studying this issue and soliciting further input from stakeholders in the future. See the response to comments received on question I.5.

I.8. If new standards were to be developed for SCC, what key issues should they address? Should they be voluntary?

1. NACE International suggested that existing standards should be updated and improved rather than developing new standards, noting that such updating is as normal part of the standards process.

2. INGAA and a number of its pipeline operators supported the development of voluntary standards to cover detection, assessment, mitigation, periodic assessment, and evaluation of effectiveness.

3. Panhandle supported the development of industry standards to manage SCC but does not believe that such a document can be completed until the gaps in the understanding of SCC have been addressed.

4. GPTC, Ameren Illinois, and Northern Natural Gas opined that the combination of ASME/ANSI B31.8S and ASME STP–PT–011 provide adequate guidance.

5. Atmos recommended that further investigation be required if SCC outside of the criterion specified in NACE SP0204–2008 is found. Atmos stated that any new standards that are developed should be voluntary so that operators have additional methodologies available for mitigating the threat of SCC as currently required by § 192.929.

6. Texas Pipeline Association and Texas Oil & Gas Association recommended any new standards for SCC apply only to Class 1 locations, based on their conclusion that pipe designed for Class 2 conditions (and above) is not susceptible to SCC.

Response to Question I.8 Comments

PHMSA appreciates the information provided by the commenters and agrees that sufficient information is not available at this time to specify prescriptive standards for SCC management. PHMSA will be studying this issue and soliciting further input from stakeholders in the future. See the response to comments received on question I.5.

I.9. Does the definition of corrosive gas need to clarify that other constituents of a gas stream (e.g., water, carbon dioxide, sulfur and hydrogen sulfide) could make the gas stream corrosive? If so, why does it need to be clarified?

1. INGAA, supported by a number of its pipeline operators, opined that the existing regulations are adequate, and commented that prescriptive limits, such as those in § 192.620, would not be as effective in reducing the potential for internal corrosion.

2. GPTC recommended that § 192.476 be revised to reflect only those liquids that act as an electrolyte (*i.e.,* water).

3. AGA sees no need to clarify the definition and noted that the stated constituents pose no threat if water is not present.

4. Atmos, Paiute, and Southwest Gas noted that gas tariffs maintain gas quality and water must be present with the constituents listed to produce a corrosive gas stream. Paiute opined that § 192.929 and ASME/ANSI B31.8S are sufficient.

5. NACE International expressed uncertainty as to why the definition needs to be clarified. NACE also noted that there are more factors than those listed in the question that affect the corrosiveness of a gas stream.

6. MidAmerican, Ameren Illinois, and Northern Natural Gas noted that ASME/ANSI B31.8S requires analysis of gas constituents and argued that operators know what constitutes a corrosive gas stream. The operators do not believe the definition needs to be changed.

7. Kern River suggested that the definition should be changed, noting that water must be present, in addition to the listed constituents, to make a gas stream corrosive.

8. Texas Pipeline Association and Texas Oil & Gas Association suggested no change to the definition is needed, since operators understand the listed constituents, when combined with water, can cause internal corrosion.

9. An anonymous commenter suggested that PHMSA not attempt to list constituents that could make a gas stream corrosive, arguing there are too many scenarios to cover. The commenter noted that the issue is not simple: H_2O w/o free O_2, or CO_2 or sulfur alone are not corrosive.

Response to Question I.9 Comments

PHMSA appreciates the information provided by commenters, and consistent with the majority of comments, PHMSA does not propose to revise the definition of corrosive gas at this time. However, PHMSA does propose to clarify the regulations by listing examples of constituents that are potentially corrosive, and to propose objective performance criteria for monitoring gas stream contaminants for HCA segments.

I.10. Should PHMSA prescribe for HCAs and non-HCAs external corrosion control survey timing intervals for close interval surveys that are used to determine the effectiveness of CP?

1. INGAA, supported by a number of pipeline operators, suggested that safety would be best served by following a risk-based approach to determine intervals for corrosion control or close interval surveys, arguing that prescriptive requirements applicable to all pipelines would divert safety resources from other high-risk tasks.

2. AGA, GPTC, and a number of pipeline operators argued that there is no reason for PHMSA to specify timing of close interval surveys, contending that the current subpart I requirements have proven to be successful and the use of CIS as an indirect assessment tool is built into NACE SP0502.

3. Ameren Illinois opposed the prescribed intervals for close interval surveys, arguing that § 192.463 and 192.465 are adequate. In addition, Ameren noted that § 192.917(e)(5) requires an operator to evaluate and remediate corrosion in both covered and non-covered segments when corrosion is found.

4. Atmos opposed required timing for close interval surveys, arguing that CIS is just one tool that can be used to determine the effectiveness of CP.

5. MidAmerican expressed its conclusion that establishing required timing intervals for close interval surveys would not be beneficial. MidAmerican noted that specific pipeline characteristics need to be taken

into consideration in establishing inspection intervals.

6. Paiute and Southwest Gas opposed required periodicity for close interval surveys, arguing that NACE SP0207 provides adequate guidance.

7. Northern Natural Gas commented that PHMSA should not prescribe external corrosion control survey intervals for close interval surveys, noting that its integrity management program demonstrates that external corrosion is being managed effectively.

8. Texas Pipeline Association and Texas Oil & Gas Association argued that industry experience demonstrates existing requirements are adequate.

9. An anonymous commenter suggested that specified periodicity for close interval surveys could have benefit, especially where a history of external corrosion exists.

Response to Question I.10 Comments

PHMSA appreciates the information provided by the commenters. Recent experience, including the December 2012 explosion near Sissonville, WV and the 2007 incident near Delhi, LA, underscores the need to be more attentive to external corrosion mitigation activities. PHMSA proposes to enhance the requirements of subpart I to require that operators conduct close-interval surveys if annual test station readings indicate that cathodic protection is below the level of protection required in subpart I, or to restore adequate corrosion control. For HCA segments, PHMSA proposes to address these requirements in enhanced preventive and mitigative measures, to include an objective timeframe for restoration of deficient cathodic protection.

I.11. Should PHMSA prescribe for HCAs and non-HCAs corrosion control measures with clearly defined conditions and appropriate mitigation efforts? If so, why?

1. INGAA stated it does not believe it is feasible to develop prescriptive measures that identify necessary and sufficient monitoring and mitigation efforts in all environments. A number of pipeline operators supported INGAA's comments.

2. AGA and a number of its operator members expressed their conclusion that the requirements of subpart I are sufficient, noting that they address HCA and non HCA alike.

3. GPTC commented that the question does not make clear why additional measures should be prescribed given that operators have been successfully mitigating corrosion deficiencies for many years.

4. Ameren Illinois expressed its conclusion that the science of corrosion mitigation is sufficiently advanced and appropriate mitigation measures are well known. Atmos, Paiute, and Southwest Gas agreed, concluding that subpart I is sufficient when implemented properly by appropriately trained and qualified personnel.

5. MidAmerican opposed new requirements, arguing that current regulations address all practical mitigation efforts.

6. Texas Pipeline Association and Texas Oil & Gas Association suggested that more time should be allowed before additional prescriptive requirements on cathodic protection are considered, noting that corrosion leaks are trending downward.

7. The Commissioners of Wyoming County Pennsylvania suggested that it is reasonable that PHMSA prescribe corrosion control measures for HCAs and non-HCAs with clearly defined conditions and appropriate mitigation efforts. They cited information from NACE indicating that 25 percent of all accidents are caused by corrosion and these accidents account for 36 percent of all accident damage. The Commissioners noted that gathering lines in the Marcellus Shale area have diameters and pressures similar to transmission lines and should be subjected to the same requirements.

8. An anonymous commenter recommended that PHMSA not prescribe specific measures.

Response to Question I.11 Comments

PHMSA appreciates the comments provided, and consistent with the majority of comments, does not propose additional regulatory changes at this time, other than to prescribe measures to promptly restore cathodic protection, as discussed in the response to comments received for question I.10.

PHMSA is interested in the extent to which operators have implemented Canadian Energy Pipeline Association (CEPA) SCC, Recommended Practices 2nd Edition, 2007, and what the results have been.

I.12. Are there statistics available on the extent to which gas transmission pipeline operators apply the Canadian Energy Pipeline Association (CEPA) practices?

I.13. Are there statistics available that compare the number of SCC indications detected and SCC-related failures between operators applying the CEPA practices and those applying other SCC standards or practices?

1. INGAA reported that most major operators in North America have adopted threat management closely aligned to CEPA standards, but that no specific data exist that correlate the use of CEPA methods to anomaly detection. INGAA reported a Joint Industry Project (JIP) study that shows that applying NACE SP0204, ASME/ANSI B31.8S, CEPA, and other standards has led to a significant reduction in in-service failures. Numerous pipeline operators supported INGAA comments.

2. AGA, supported by a number of its pipeline operator members, questioned why a discussion of CEPA standards was included in the ANPRM. AGA suggested that CEPA practices are well suited to Canadian infrastructure, but not necessarily applicable in the United States and noted that CEPA is not often discussed by Canadian members at AGA meetings.

3. GPTC expressed that its membership has little knowledge of CEPA standards, commented that it is not clear what is meant by full life cycle concerns, and argued that existing standards and regulations adequately address SCC concerns. GPTC is not aware of any data correlating the efficacy of CEPA to other standards.

4. Paiute and Southwest Gas reported that they have not implemented CEPA standards.

Response to Questions I.12 and I.13 Comments

PHMSA appreciates the information provided by the commenters. PHMSA acknowledges the comments provided on the use of the CEPA SCC Recommended Practice and will consider that standard in its study of comprehensive safety requirements for SCC.

I.14. Do the CEPA practices address the full life cycle concerns associated with SCC? If not, which are not addressed?

1. INGAA reported its conclusion that CEPA standards address full life cycle concerns for near-neutral SCC. Many management techniques in CEPA standards are also applicable to high-pH SCC, but the two are not identical. Several pipeline operators supported INGAA's comments.

2. Texas Pipeline Association and Texas Oil & Gas Association expressed their conclusion that CEPA standards address the full life cycle concerns of SCC.

Response to Question I.14 Comments

PHMSA appreciates the information provided by the commenters. PHMSA acknowledges the comments provided on the use of the CEPA SCC Recommended Practice and will consider that standard in its study of

comprehensive safety requirements for SCC.

I.15. Are there additional industry practices that address SCC?

1. INGAA, supported by a number of its pipeline operator members, reported that there are no related European standards and Australia has a standard similar to ASME/ANSI B31.8S. INGAA noted that SCC failures of pipelines installed since 1980 are rare and observed that quality coating and cathodic protection are the most effective means of preventing SCC.

2. GPTC stated that NACE SP0204 and 35103, ASME/ANSI B31.8S, and GPTC guide material address SCC. Paiute and Southwest Gas agreed that NACE standards and GPTC provide relevant guidance.

3. AGA commented that it does not have the statistics available to advise whether or not additional requirements are needed to address SCC threats.

4. Atmos, Texas Pipeline Association and Texas Oil & Gas Association reported that they have no knowledge of other SCC standards or practices.

5. Northern Natural Gas cited ASME/ANSI B31.8S and ASME STP–PT–011.

Response to Question I.15 Comments

PHMSA appreciates the information provided by the commenters. PHMSA acknowledges the comments provided on the standards, and will consider these standards in its study of comprehensive safety requirements for SCC.

I.16. Are there statistics available on the extent to which various tools and methods can accurately and reliably detect and determine the severity of SCC?

1. INGAA noted that the measurement of ILI crack detection tool performance is an ongoing research activity, both within JIP Phase II and within the Pipeline Research Council International, which is actively supported by the tool vendors and the pipeline operators. Several issues regarding the acquisition and interpretation of information need to be standardized by the practitioners before a clear picture can emerge. The implications of tool tolerance on predicted failure pressure are being studied in the JIP Phase II.

2. GPTC, Atmos, Paiute, Southwest Gas, and an anonymous commenter reported that they are unaware of any relevant statistics.

3. Northern Natural Gas reported that it has used electro-magnetic acoustic transducer (EMAT) ILI with some success.

4. Panhandle commented that magnetic particle inspection (MPI) is effective at locating surface-breaking linear indications, a subset of SCC. Furthermore, abrasive wheel grinding in conjunction with MPI is an effective method to size the length and depth of surface-breaking linear indications, limited by the amount of metal that can be removed from in-service pipelines. Panhandle noted that PRCI research indicates that laser UT techniques can effectively locate and size SCC, but this method is relatively new and Panhandle has no experience with its use. Panhandle also reported that the use of EMAT has yet to be acknowledged as a replacement for hydrostatic testing but it is being evaluated in Phase II of the SCC Joint Industry Project (JIP); results of the study will be used to determine the path forward for EMAT technology.

5. Texas Pipeline Association and Texas Oil & Gas Association reported that they have no knowledge of relevant references other than the Baker study.

Response to Question I.16 Comments

PHMSA appreciates the information provided by the commenters and will consider this information in its study of comprehensive safety requirements for SCC.

I.17. Are tools or methods available to detect accurately and reliably the severity of SCC when it is associated with longitudinal pipe seams?

1. INGAA and a number of pipeline operators noted that detecting SCC close to a longitudinal seam is difficult and even harder near a girth weld. INGAA commented that developing tools to reliably detect and assess SCC near longitudinal seams is a continuing challenge.

2. GPTC reported that SCC tools are available; however, GPTC cautioned that the ability to accurately and reliably detect the severity of SCC associated with longitudinal seams is dependent on specific operating conditions.

3. Atmos commented that it knows of no tools that can accurately detect and estimate the severity of SCC near a longitudinal seam.

4. Paiute and Southwest Gas reported that tools are being developed but are, as of yet, not accurate at determining the severity of SCC associated with longitudinal seams.

5. Northern Natural Gas reported that it has used electro-magnetic acoustic transducer (EMAT) ILI with some success. Panhandle added that difficulties in using EMAT are further complicated when cracking is associated with a longitudinal seam.

6. Texas Pipeline Association and Texas Oil & Gas Association expressed their conclusion that the best methods to assess for SCC near longitudinal seams are pressure testing and EMAT, although they noted that some operators have had success with transverse flux ILI.

7. An anonymous commenter reported that new ILI tools exist but that analysts are not yet consistent in using them.

Response to Question I.17 Comments

PHMSA appreciates the information provided by the commenters and will consider this information in its study of comprehensive safety requirements for SCC.

I.18. Should PHMSA require that operators perform a critical analysis of all factors that influence SCC to determine if SCC is a credible threat for each pipeline segment? If so, why? What experience based indications have proven reliable in determining whether SCC could be present?

1. INGAA, supported by a number of pipeline operators, noted that operators are already required to perform an analysis to determine the likelihood of SCC. INGAA added that operators address the pipelines with the highest likelihood of SCC and apply lessons learned, as appropriate, to lower-likelihood pipelines.

2. Texas Pipeline Association and Texas Oil & Gas Association indicated that a requirement to perform a critical analysis for SCC is unnecessary, since guidance in ASME/ANSI B31.8S is sufficient. Northern Natural Gas also stated that additional requirements are unnecessary, noting that it conducted an analysis of critical factors affecting SCC and identified no new factors over those in B31.8S, Appendix 3.

3. Atmos stated that PHMSA's question was unclear whether to expand the threat of SCC to all pipeline segments or expand the requirements for investigating the presence of SCC within HCA segments? Atmos concluded that subpart O requirements provide a framework for operators to integrate data, rank risk, identify threats, and apply appropriate mitigative actions; additional requirements are not needed.

4. Texas Pipeline Association and Texas Oil & Gas Association suggested that PHMSA conduct a workshop to share industry experience with SCC.

Response to Question I.18 Comments

PHMSA appreciates the information provided by the commenters and will consider this information in its study of comprehensive safety requirements for SCC.

I.19. Should PHMSA require an integrity assessment using methods capable of detecting SCC whenever a credible threat of SCC is identified?

1. INGAA, Panhandle, Atmos, and Northern Natural Gas noted that subpart O already requires that all credible threats be identified and assessed. A number of pipeline operators supported INGAA's comments.

2. Texas Pipeline Association and Texas Oil & Gas Association also indicated that they read subpart O as requiring assessment using a method that can detect SCC if that threat is credible. The associations both added, however, that they would not object to making this requirement more explicit.

3. GPTC opined that existing regulations and standards are adequate to address SCC issues.

4. Southwest Gas opposed a new requirement, noting that § 192.929 and ASME/ANSI B31.8S are sufficient.

Response to Question I.19 Comments

PHMSA appreciates the information provided by the commenters and will consider this information in its study of comprehensive safety requirements for SCC. As indicated above in the response to comments received on question I.5, PHMSA proposes more explicit requirements for selection of appropriate methods for integrity assessments for SCC.

I.20. Should PHMSA require a periodic analysis of the effectiveness of operator corrosion management programs, which integrates information about CP, coating anomalies, in-line inspection data, corrosion coupon data, corrosion inhibitor usage, analysis of corrosion products, environmental and soil data, and any other pertinent information related to corrosion management? Should PHMSA require that operators periodically submit corrosion management performance metric data?

1. INGAA, Kern River, Paiute, and Southwest Gas commented that these issues are already addressed in subpart O, which requires operators to keep records, measure program effectiveness, continually evaluate and assess systems, integrate data, and show continual improvement. INGAA added that metrics bearing on the effectiveness of a corrosion control program are already among those required to be collected by ASME/ANSI B31.8S. These metrics are not required to be submitted, but are available for review during inspections. A number of pipeline operators supported INGAA's comments.

2. MidAmerican commented that subparts I and O include these requirements. Northern Natural Gas agreed that it manages these threats through O&M and IM activities.

3. Panhandle noted that subpart I requires operators to maintain effective corrosion control programs to mitigate the threat of corrosion and § 192.945 requires operators to measure, on a semi-annual basis, whether the integrity management program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting HCAs.

4. GPTC and AGA, supported by a number of its pipeline operator members, opposed requiring operators to submit corrosion management metrics. AGA noted that operators need flexibility to select the appropriate analysis methods and key performance indicators. Furthermore, operators review corrosion control program effectiveness, and plans of intrastate operators are reviewed by state commissions.

5. Ameren Illinois opposed new requirements, noting that subpart O already requires operators to identify and respond to risks.

6. Atmos questioned whether PHMSA is proposing to measure the effectiveness of corrosion management programs across all pipeline segments or to measure the effectiveness of corrosion management programs in HCA segments. Atmos added that the data points enumerated by PHMSA in this question would be difficult to gather on an operator's entire pipeline system.

7. Texas Pipeline Association and Texas Oil & Gas Association stated that they do not see a need for a requirement to periodically analyze the effectiveness of an operator's corrosion management program, arguing that existing requirements are sufficient.

8. Panhandle argued that the standardization of corrosion control efforts, as would be required for performance metric tracking, would require additional prescriptive requirements in subpart O. Panhandle does not believe that elimination of performance-based language is beneficial.

9. The Commissioners of Wyoming County Pennsylvania suggested that any communication between operators and PHMSA regarding corrosion management would be helpful in facilitating operator compliance and best practices.

10. Paiute and Southwest Gas reported that they opposed a requirement to report additional performance metrics absent a definition of how new data would be collected and used.

Response to Question I.20 Comments

PHMSA appreciates the information provided by the commenters. Following publication of the ANPRM, the NTSB issued recommendations in response to the San Bruno pipeline incident, including a specific recommendation (P–11–19) that PHMSA establish standards for evaluating effective program performance. PHMSA will evaluate standards for integration of pipeline corrosion data to enhance corrosion management performance as part of its response to that recommendation.

I.21. Are any further actions needed to address corrosion issues?

1. INGAA, supported by a number of its pipeline operator members, commented that continued study and evaluation of the root causes of the San Bruno explosion, documentation of findings, and communication of results are needed rather than additional prescriptive requirements.

2. AGA, GPTC, and a number of pipeline operators argued that no further action is needed, given that current methodologies adequately address corrosion issues and operators are subject to periodic audits by federal and state safety regulators.

3. Accufacts suggested that PHMSA needs to assure that IM programs are not solely relied upon to prevent corrosion failure.

4. Texas Pipeline Association and Texas Oil & Gas Association reported that they do not see any deficiencies necessitating new regulations.

Response to Question I.21 Comments

PHMSA appreciates the information provided by the commenters. As discussed above, PHMSA is proposing some enhanced measures for corrosion control in subpart I and subpart O.

I.22. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

J. Pipe Manufactured Using Longitudinal Weld Seams

The ANPRM requested comments regarding additional integrity management and pressure testing

requirements for pipe manufactured using longitudinal seam welding techniques that have not had a subpart J pressure test. Pipelines built since the regulations (49 CFR part 192) were implemented in early 1971 must be:

- Pressure tested after construction and prior to being placed into gas service in accordance with subpart J; and
- Manufactured in accordance with a referenced standard (most gas transmission pipe has been manufactured in accordance with American Petroleum Institute Standard 5L, 5LX or 5LS, ''Specification for Line Pipe'' (API 5L) referenced in 49 CFR part 192).

Many gas transmission pipelines built from the 1940's through 1970 were manufactured in accordance with API 5L, but may not have been pressure tested similar to a subpart J pressure test. For pipelines built prior to 1971, § 192.619(a) allows MAOP to be based on the highest 5-year operating pressure established prior to July 1, 1970, in lieu of a pressure test. Accordingly, some of this pre-existing pipe possesses variable characteristics throughout the longitudinal weld or pipe body.

As a result of 12 hazardous liquid pipeline failures that occurred during 1986 and 1987 involving pre-1970 ERW pipe, PHMSA issued an alert notice (ALN–88–01, January 28, 1988) to advise operators with pre-1970 ERW pipe of the 12 pipeline failures and the actions to take. Subsequent to this notice, one additional failure on a gas transmission pipeline, and eight additional failures on hazardous liquid pipelines occurred, which resulted in PHMSA issuing another alert notice (ALN–89–01, March 8, 1989) to advise operators of additional findings since the previous alert notice. These notices identified the fact that some failures appeared to be due to selective seam weld corrosion, but that other failures appeared to have resulted from flat growth of manufacturing defects in the ERW seam. In these notices, PHMSA specifically advised all gas transmission and hazardous liquid pipeline operators with pre-1970 ERW pipe to consider hydrostatic testing of affected pipelines, to avoid increasing a pipeline's long-standing operating pressure, to assure effectiveness of the CP system, and to conduct metallurgical exams in the event of an ERW seam failure.

Since 2002, there have been at least 22 reportable incidents on gas transmission pipeline caused by manufacturing or seam defects. In addition, recent high consequence incidents, including the 2009 failure in Palm City, Florida and the 2010 failure in San Bruno, California, have been caused by longitudinal seam failures.

The ANPRM listed questions for consideration and comment. The following are general comments received related to the topic as well as comments related to the specific questions:

General Comment for Topic J

1. Texas Pipeline Association and Texas Oil & Gas Association suggested that seam issues are best addressed through inspection, detection, remediation, and monitoring, based on specific segments, not a one-size-fits-all requirement.

Response to General Comment for Topic J

PHMSA appreciates the comment and agrees that a one-size-fits-all requirement is not the best approach. Accordingly, PHMSA proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines, that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Verification of MAOP includes establishing and documenting MAOP if the pipeline segment: (1) Has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''); (2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; or (ii) a class 3 or class 4 location; or (3) the pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before *[effective date of rule]* and is located in one of the following areas: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

In addition, the proposed rule would allow operators to select from among several approaches to verify MAOP based on segment specific issues and limitations, such as pressure testing, pressure reduction based on historical operating pressure, and engineering critical assessment.

Comments submitted for questions in Topic J.

J.1. Should all pipelines that have not been pressure tested at or above 1.1 times MAOP or class location test criteria (§§ 192.505, 192.619 and 192.620), be required to be pressure tested in accordance with the present regulations? If not, should certain types of pipe with a pipeline operating history that has shown to be susceptible to systemic integrity issues be required to be pressure tested in accordance with the present regulations (e.g., low-frequency electric resistance welded (LF–ERW), direct current electric resistance welded (DC–ERW), lap-welded, electric flash welded (EFW), furnace butt welded, submerged arc welded, or other longitudinal seams)? If so, why?

1. AGA, GPTC, and numerous pipeline operators opposed a requirement to pressure test all lines not previously tested. These commenters supported the more-limited testing mandated by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. AGA noted that Congress considered and rejected proposals for more extensive testing.

2. AGA, GPTC, Iowa Utilities Board, Iowa Association of Municipal Utilities, Texas Pipeline Association, Texas Oil & Gas Association, and several distribution pipeline operators objected to requiring pressure testing of distribution pipelines. The commenters argued that the impact of resulting service disruptions was overlooked. Pressure testing would necessitate disruptions of three to seven days for many distribution pipelines, sometimes involving service to an entire town. In some cases, establishing an alternate supply is not always possible. In addition, some in-service lines are not configured in a manner that would support testing. For these reasons, the commenters argued that the high costs to perform pressure tests were inappropriate absent some demonstration of actual risk. MidAmerican added a suggestion that such a requirement of this type be

limited to pipelines operating above 30 percent of specified minimum yield strength (SMYS). Northern Natural Gas agreed with MidAmerican's suggestion and would further limit any testing requirement to pipelines outside of Class 1 locations and subject to seam issues.

3. INGAA, GPTC, Texas Pipeline Association, Texas Oil & Gas Association, and several pipeline operators opposed a blanket testing requirement for older pipelines. The commenters noted that more than sixty percent of in-service pipelines were installed prior to 1970, and have operated safely. INGAA argued that the objective of any action in this area should not be pressure testing, per se, but verification of fitness for service. INGAA noted that all of the listed pipe types are addressed in its Fitness for Service protocol, which would be more effective and efficient than a prescriptive test requirement. A number of additional pipeline operators supported INGAA's comments.

4. Accufacts recommended that all pipelines with at-risk seam anomalies be pressure tested to at least 90% SMYS, with priority given to lines operating under an MAOP established in accordance with 49 CFR 192.619(c).

5. Texas Pipeline Association and Texas Oil & Gas Association noted that pressure testing alone, is not sufficient to prove the integrity of pipelines subject to seam issues. The associations argued that verification must also consider any degradation mechanism present in the seam.

6. Dominion East Ohio supported a requirement to pressure test pipe susceptible to seam failure for which adequate test documentation does not exist.

7. Pipeline Safety Trust, California Public Utilities Commission, Commissioners of Wyoming County Pennsylvania, and an anonymous commenter supported requiring a pressure test for all pipelines not already tested to current requirements. The commenters argued that integrity management should have led to necessary testing but has not done so in all cases. They also noted that such a requirement would respond to an NTSB recommendation.

8. The Environmental Defense Fund (EDF) cautioned that any requirement for pressure testing should assure that the amount of gas blown down to the atmosphere is minimized. It noted that methane is a potent greenhouse gas, and uncontrolled blowdown of 182,000 miles of gas transmission pipeline would be approximately equivalent to the annual greenhouse gas release from 9–14 million autos.

Response to Question J.1 Comments

PHMSA appreciates the information provided by the commenters. This NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Verification of MAOP includes establishing and documenting MAOP using one or more of the methods in § 192.624(c)(1) through (c)(6). With regard to the EDF comment regarding the environmental cost due to gas blow down during pressure testing, PHMSA considered this in the rule development. The proposed rulemaking is written to minimize pressure testing. The Integrity Verification Process allows MAOP verification through ILI and ECA. PHMSA believes operators will pressure test as a last resort because it is the costliest methodology. PHMSA estimates that the rule would result in approximately 1,300 miles of pipe being pressure tested. The gas release from controlled low volume release during pressure testing is much less than an uncontrolled high volume release as a result of rupture. The proposed rule is expected to prevent incidents, leaks, and other types of failures that might occur, thereby preventing future releases of greenhouse gases (GHG) to the atmosphere, thus avoiding additional contributions to global climate change. PHMSA estimated net GHG emissions abatement over 15 years of 69,000 to 122,000 metric tons of methane and 14,000 to 22,000 metric tons of carbon dioxide, based on the estimated number of incidents averted and emissions from pressure tests and ILI upgrades.

J.2. Are alternative minimum test pressures (other than those specified in subpart J) appropriate, and why?

1. INGAA, supported by a number of pipeline operators, argued that there is no evidence suggesting that subpart J test pressures are inadequate. INGAA added that there are circumstances in which additional tests to 1.25 times MAOP may be appropriate to verify fitness for service. This is consistent with ASME/ANSI B31.8S and addressed in its Fitness for Service protocol.

2. Texas Pipeline Association, Texas Oil & Gas Association, and Atmos argued that a pressure test at the time of construction is adequate. The associations further added that operating practices since part 192 became effective can also verify fitness for service, if primary test records are not available, particularly if MAOP is reduced.

3. AGA, GPTC, and a number of pipeline operators commented that any test to pressures greater than MAOP has some value. AGA noted that even tests to 1.1 times MAOP would identify the most severe defects that have the potential to adversely affect pipeline integrity.

4. MidAmerican suggested that a fitness for service evaluation should be allowed if there are service interruption issues and for pre-1970 pipelines. MidAmerican would allow testing for existing pipelines, to 1.1 or 1.25 times MAOP or to mill test pressures if they are less than would be required by subpart J.

5. An anonymous commenter argued that alternative minimum test pressures are not appropriate, since they provide no more information than successful operation at normal operating pressures.

6. Accufacts suggested that pipelines tested to lower pressures and that have been subject to aggressive operating cycles be considered for high-pressure testing. Accufacts would also require test pressures be recorded both in psig and percent SMYS.

Response to Question J.2 Comments

PHMSA appreciates the information provided by the commenters. Following publication of the ANPRM, the NTSB issued its report on the San Bruno incident that included a recommendation for this issue (P–11–15). The NTSB recommended that PHMSA amend its regulations so that manufacturing- and construction-related defects can only be considered ''stable'' if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP. This NPRM proposes to revise the integrity management requirement in 192.917(e)(3) to allow the presumption of stable manufacturing and construction defects only if the pipe has been pressure tested to at least 1.25 times MAOP. In addition, PHMSA proposes to revise pressure test safety factors in § 192.619(a)(2)(ii) to correspond to at least 1.25 MAOP for newly installed pipelines.

J.3. Can ILI be used to find seam integrity issues? If so, what ILI technology should be used and what inspection and acceptance criteria should be applied?

1. INGAA and numerous pipeline operators noted that ILI tools can examine seam issues but the technology to identify and evaluate seam anomalies is still evolving. INGAA added that there are significant burdens associated

with requiring pressure testing as an alternative.

2. AGA reported that its discussions with ILI vendors have identified that ILI can detect seam issues but detection is dependent on many conditions and is not guaranteed.

3. Texas Pipeline Association and Texas Oil & Gas Association argued that ILI conducted using a multi-purpose tool can provide a seam assessment equivalent to pressure testing for detection of seam integrity issues, depending on anomaly characteristics and the ILI method used.

4. Northern Natural Gas commented that ILI can be used to detect seam anomalies. Analysis of anomalies is based on the log-secant method with consideration of toughness to determine the predicted failure pressure ratio. The response criteria can then be based on the failure pressure versus maximum allowable operating pressure, similar to wall loss. Northern noted that this is consistent with ASME/ANSI B31.8 and B31.8S.

5. Accufacts commented that ILI cannot, at present, reliably detect all seam anomalies.

Response to Question J.3 Comments

PHMSA appreciates the information provided by the commenters. PHMSA proposes requirements in the rulemaking to address the use of ILI for seam integrity issues. This includes incorporating industry standard NACE SP0102–2010 into the regulations to provide better guidance for conducting integrity assessments with in-line inspection. In addition, for pipe segments subject to MAOP verification in new § 192.624, specific guidance is provided for analyzing crack stability when using engineering critical assessment in conjunction with inline inspection to address seam or other cracking issues.

J.4. Are other technologies available that can consistently be used to reliably find and remediate seam integrity issues?

1. INGAA and numerous pipeline operators noted that magnetic particle inspection is now being used by many operators when pipe with disbanded coating is exposed.

2. GPTC, Northern Natural Gas, and MidAmerican reported that there are other methods that are useful under some circumstances, such as x-ray or other forms of radiography and guided wave ultrasound.

3. Texas Pipeline Association, Texas Oil & Gas Association, and Atmos noted that radiography, ultrasonic testing (UT), and shear wave UT are now being tested.

4. AGA, supported by a number of its pipeline operator members, noted that operators must have the flexibility to select appropriate tools without prior PHMSA approval. AGA argued that technology is advancing rapidly and that PHMSA stifles advancement by requiring prior approval of new inspection tools. AGA argued that some requirements being imposed on the use of other technologies are effectively regulations imposed without formal rulemaking, citing limitations imposed on the use of guided wave ultrasound as an example.

5. Atmos recommended that PHMSA modify its regulations to allow operators to use appropriate methods to evaluate seam integrity without requiring approval as ''other technology.''

6. Accufacts opined that pressure testing and cyclic monitoring and analysis are the only useful technologies currently available.

Response to Question J.4 Comments

PHMSA appreciates the information provided by the commenters. PHMSA proposes requirements in the rulemaking to address the use of best available technology, including use of electromagnetic acoustic transducers (EMAT) or ultrasonic testing (UT) tools to assess seam integrity issues. In addition, proposed requirements include performing fracture mechanics modeling for failure stress pressure and cyclic fatigue crack growth analysis to assess crack or crack-like defects. These requirements would apply to any segment that required verification of MAOP.

J.5. Should additional pressure test requirements be applied to all pipelines, or only pipelines in HCAs, or only pipelines in Class 2, 3, or 4 location areas?

1. INGAA and several pipeline operators argued that existing requirements are adequate and any verification beyond those requirements should rely on INGAA's Fitness for Service protocol. INGAA argued that its protocol is consistent with Section 23 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011.

2. MidAmerican suggested any new requirements should focus on pipe with manufacturing and construction defects and should prioritize pipelines in Class 3 and 4 areas and HCAs. MidAmerican sees little benefit in testing other pipelines.

3. An anonymous commenter recommended additional unspecified requirements be applied to pipelines in Class 3 and 4 areas and HCAs.

4. The California Public Utilities Commission would apply pressure testing requirements to HCAs that are determined by the method described in paragraph 1 in the definition of HCA in § 192.903, as a minimum.

5. The Iowa Utilities Board and the Iowa Association of Municipal Utilities argued that class location is not a reasonable basis for determining where to apply pressure testing requirements, given that class location has no relationship to risk. These commenters noted that small-diameter, low-pressure lines could be Class 3, even with no structures intended for human occupancy within a potential impact radius.

6. The Commissioners of Wyoming County Pennsylvania would apply requirements to all transmission and gathering pipelines, including those in Class 1 locations.

7. Thomas Lael noted that all pipelines have been tested once, after construction.

Response to Question J.5 Comments

PHMSA appreciates the information provided by the commenters. This NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Use of the MCA location criteria would apply to pipe segments where dwellings, occupied sites, or interstate highways, freeways, and expressways, and other principal 4-lane arterial roadways are located within the potential impact radius, but would not necessarily include all class 3 or 4 locations. Verification of MAOP includes establishing and documenting MAOP using one or more of the methods in 192.624(c)(1) through (c)(6). In addition, this NPRM proposes requirements for verification of pipeline material in new § 192.607 for existing onshore, steel, gas transmission pipelines that are located in an HCA or class 3 or class 4 locations.

J.6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements pursuant to commenter's suggestions.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*

• *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

K. Establishing Requirements Applicable to Underground Gas Storage

Underground storage facilities are comprised of wells and associated separation, compression, and metering facilities to inject and withdraw natural gas at high pressures from depleted hydrocarbon reservoirs and salt caverns. Pipelines that transport gas within a storage field are defined in § 192.3 as transmission pipelines and are regulated by PHMSA, while underground storage facilities including surface and subsurface well casing, tubing, and valves are not currently regulated under part 192. In the ANPRM, PHMSA provided a brief history of a 1992 accident that occurred in Brenham, Texas an involving underground storage facility. This incident involved an uncontrolled release of highly volatile liquids from a salt dome storage cavern that resulted in 3 fatalities, 21 people treated for injuries at area hospitals, and damages in excess of $9 million. Following the incident, the National Transportation Safety Board (NTSB) conducted an investigation that resulted in a recommendation for the Research and Special Programs Administration, the precursor to PHMSA, to initiate a rulemaking proceeding. Following a period of study, RSPA terminated that rulemaking. RSPA described this action in an Advisory Bulletin published in the **Federal Register** on July 10, 1997 (ADB–97–04, 62 FR 37118).

Since publication of the 1997 Advisory Bulletin, significant incidents have continued to occur involving underground gas storage facilities. The most significant incident occurred in 2001 near Hutchinson, Kansas. An uncontrolled release from an underground gas storage facility resulted in an explosion and fire, in which two people were killed. Many residents were evacuated from their homes and were not able to return for four months.

The Kansas Corporation Commission initiated enforcement action against the operator of the Hutchinson storage field as a result of safety violations associated with the accident. As part of this enforcement proceeding, it was concluded that the storage field was an interstate gas pipeline facility. Federal statutes provide that ''[a] State authority may not adopt or continue in force safety standards for interstate pipeline facilities or interstate pipeline transportation'' (49 U.S.C. 60104). There were, and remain, no federal safety standards against which enforcement could be taken. Therefore, the enforcement proceeding was terminated.

The ANPRM listed questions for consideration and comment. The following are general comments received related to this topic as well as comments related to the specific questions:

General Comments for Topic K

1. AGA, supported by a number of pipeline operators, suggested that any proceeding addressing gas storage be conducted under a docket separate from any pipeline requirements, arguing that the relevant engineering and regulatory concepts are vastly different.

2. The Kansas Department of Health and Environment (KDHE) noted that the ANPRM misstated the agency that took enforcement action in the case of the Kansas gas storage incident previously discussed. That action was taken by KDHE, and not the Kansas Corporation Commission, as stated.

3. Kansas Corporation Commission recommended that PHMSA work with the states to have Congress amend the Pipeline Safety Act to allow the states to regulate interstate and intrastate gas storage wellbores. KCC noted that current federal regulations undermine the ability of states to regulate gas storage facilities, as in the 2001 accident where Kansas attempted to take enforcement as a result of a serious incident but was precluded from doing so by pre-emption of federal regulations.

4. The Interstate Oil & Gas Compact Commission argued that states should be mandated to regulate gas storage wellbores, whether interstate or intrastate.

5. The Texas Pipeline Association and Texas Oil & Gas Association opposed new requirements, arguing that there has been no demonstration of undue risk or insufficiency of current regulations.

Comments submitted for questions in Topic K.

K.1. Should PHMSA develop Federal standards governing the safety of underground gas storage facilities? If so, should they be voluntary? If so, what portions of the facilities should be addressed in these standards?

1. INGAA suggested that PHMSA develop high-level, performance-based guidelines that acknowledge and reflect existing applicable state rules to address regional and geologic variations in underground storage activity. Development of guidelines should follow PHMSA's current practice of stakeholder involvement leading to development of a consensus standard and its subsequent adoption into regulations. INGAA reported that it is committed to developing a standard under the auspices of the American Petroleum Institute (API), with work beginning in 2012. INGAA cautioned that it is important to understand, and clearly state, the scope of ''gas storage,'' which it contends begins at and includes the wing valve at the wellhead, the wellhead components, the well bore, and the ''underground container'' (*i.e.,* the geologic formation). INGAA stated that PHMSA should recognize the limits and requirements imposed on gas storage by FERC, arguing that no new regulations are needed in these areas. A number of pipeline operators supported INGAA's comments, and have submitted separate comments addressing one or more of these points.

2. AGA suggested that PHMSA adopt federal performance standards, in conjunction with API. AGA argued that one-size-fits-all requirements are not appropriate in this area, since they would fail to recognize variations in wells and the geologic diversity of storage caverns and structures. AGA argued that no new requirements are needed governing maximum operating parameters and environmental conditions, since these are addressed adequately by existing federal and state certification and compliance programs related to gas storage facilities. AGA recommended that any new standards should be mandatory, but also recognize regional variations by state due to geologic and geographical diversity among storage fields. A number of pipeline operators supported AGA's comments.

3. INGAA, the Kansas Corporation Commission, and the Interstate Oil & Gas Compact Commission recommended that compliance with any new standards be mandatory, but that regulatory authority should be delegated to the states since PHMSA lacks relevant technical expertise. A number of pipeline operators supported this comment.

4. The Kansas Corporation Commission and the Interstate Oil & Gas Compact Commission recommended that any new standards cover all portions of a storage facility and that PHMSA enter into a memorandum of understanding with FERC regarding gas containment.

5. Southern Star Central Gas Pipeline agreed that the development of requirements for operation of gas storage facilities is appropriate but explicitly disagreed with Kansas Corporation Commission's suggestion that development be delegated to states.

Southern Star indicated that it would not object to the delegation of inspection and enforcement to federal standards. Southern Star noted that a federal court has held only federal regulations can be enforced against its storage facilities. The company also argued that no new requirements are needed for storage reservoirs given existing FERC regulations.

6. GPTC, Nicor, Ameren Illinois, and Atmos argued that existing regulations are sufficient and that no new standards are needed. GPTC and Nicor added that if PHMSA elects to develop new requirements, they should be limited to facilities ''affecting interstate or foreign commerce.'' Atmos added that geology and circumstances vary considerably among gas storage facilities and states have the requisite expertise to regulate storage safety.

7. Texas Pipeline Association and Texas Oil & Gas Association argued that PHMSA lacks the expertise to regulate wellbores and therefore should not attempt to develop gas storage regulations.

8. FERC, NAPSR, Interstate Oil & Gas Compact Commission, Iowa Utilities Board, Kansas Corporation Commission, and Railroad Commission of Texas recommended that PHMSA seek statutory authority to confer jurisdiction over all gas storage facilities to the states. The commenters argued that states have expertise on local geology and storage fields and could therefore regulate in a fashion similar to that of production facilities. The commenters referred to PHMSA's Advisory Bulletin ADB 97–04 as a further basis for this recommendation. FERC further suggested that PHMSA delegate inspection and enforcement activities to states if statutory changes are not forthcoming.

9. The Alaska Department of Natural Resources recommended that PHMSA develop standards in consultation with the states.

10. The NTSB encouraged the development of gas storage regulations, noting that this was the subject of its recommendation P–93–9, which it closed as ''unacceptable action,'' after a rulemaking proceeding to regulate underground gas storage was terminated in 1997.

11. A private citizen suggested that there should be some level of regulation, as gas storage is currently insufficiently regulated.

12. NAPSR commented that, in many states, the agency familiar with gas storage issues is not responsible for regulation of pipeline safety. As a result, NAPSR stated that certification of additional state agencies may be required.

13. An anonymous commenter suggested that PHMSA should develop requirements applicable to piping within gas storage facilities. The commenter argued that caverns, well heads, casing, tubing, fresh water, and brine pumping are generally regulated by states.

14. ITT Exelis Geospatial Systems suggested that PHMSA consider requirements for leak detection, noting that their LIDAR system could serve this purpose.

K.2. What current standards exist governing safety of these facilities? What standards are presently used for conducting casing, tubing, isolation packer, and wellbore communication and wellhead equipment integrity tests for down-hole inspection intervals? What are the repair and abandonment standards for casings, tubing, and wellhead equipment when communication is found or integrity is compromised?

1. AGA, INGAA, GPTC, Texas Pipeline Association, Texas Oil & Gas Association and numerous pipeline operators noted that FERC, EPA, and the states regulate various aspects of gas storage. Commenters reported that state regulations generally provide standards for wells and that EPA regulations provide standards for caverns. AGA described the aspects regulated by FERC, EPA, and the states and suggested provisions of each which might be considered for new PHMSA regulations. For example, it was recommended that a federal guideline be established to require a storage operator notification-review-and-approval process for third party wells encroaching on storage containers, which is a requirement some states currently have in place. Commenters reported that repaired wells must meet state standards for new wells and state requirements for abandonment vary. AGA indicated that interstate storage operators use state requirements as guidance in the absence of federal regulations.

2. The Kansas Department of Health and Environment, the Kansas Corporation Commission, the Railroad Commission of Texas, the Interstate Oil & Gas Compact Association, Ameren Illinois, and Atmos reported that states generally regulate gas storage. For example, in Texas, Statewide Rule 16 applies and KDHE submitted a copy of its gas storage regulations.

3. Texas Pipeline Association and Texas Oil & Gas Association noted that Texas requirements for gas storage are more similar to provisions that would govern production drilling and operations rather than pipeline operations.

K.3. What standards are used to monitor external and internal corrosion?

1. AGA, INGAA, and numerous pipeline operators noted that varying approaches are used and argued that prescriptive standards would be inappropriate given that no one tool is applicable to all wells and well casings are not available for direct examination.

2. The Railroad Commission of Texas reported that its regulations require integrity testing every five years or after a well work over. Texas regulations also require periodic casing inspections and a pipeline integrity program.

3. Northern Natural Gas reported that it uses the same measures to monitor corrosion in its gas storage facilities as it does for its pipelines.

K.4. What standards are used for welding, pressure testing, and design safety factors of casing and tubing including cementing and casing and casing cement integrity tests?

1. INGAA, AGA, the Texas Pipeline Association, the Texas Oil & Gas Association and numerous pipeline operators noted that state requirements reflect unique situations, welding is seldom used, pressure capacity is demonstrated by historical record, and casing requirements are customized for local geologic conditions. Welding, when used, is generally performed to procedures compliant with ASTM B31.8, part 192, and inspection is conducted to API–1104 criteria.

2. The Railroad Commission of Texas reported that Texas regulations are flexible to allow for site-specific decisions.

K.5. Should wellhead valves have emergency shutdowns both primary and secondary? Should there be integrity and O&M intervals for key safety and CP systems?

1. INGAA, AGA, and several pipeline operators reported that storage in salt domes generally requires emergency shutdown systems; these systems are generally not required for storage in depleted gas fields or aquifers but may be required depending on local site conditions. The commenters indicated that testing intervals are set in accordance with operator procedures and CP testing is based on an operator's local experience.

2. The Railroad Commission of Texas, the Texas Pipeline Association, and the Texas Oil & Gas Association reported that Texas' regulations require emergency shutdown systems and annual drills.

3. The Kansas Department of Health and Environment suggested that at least

the primary well should have an emergency shutdown system. KDHE stated that O&M intervals should be established for key safety systems and attached a copy of the relevant Kansas regulations to its comments.

4. Northern Natural Gas suggested that emergency shutoffs should only be required when the well is within 330 feet of a structure intended for human occupancy. Northern stated that intervals should be established for O&M activities and CP systems.

5. GPTC and Nicor expressed their opinion that no new regulations are needed in this area; decisions on emergency shutdown should be made based on local circumstances.

K.6. What standards are used for emergency shutdowns, emergency shutdown stations, gas monitors, local emergency response communications, public communications, and O&M Procedures?

1. AGA, GPTC, and several pipeline operators reported that operators generally follow DOT regulations, where applicable, and industry good practices.

2. The NTSB commented that gas storage facility information should be made available to emergency responders, per its recommendation P–11–8.

3. The Railroad Commission of Texas, the Texas Pipeline Association, the Texas Oil & Gas Association, and Atmos reported that states establish standards in these areas through their regulations.

4. The Kansas Department of Health and Environment reported that these standards are specified in its regulations, and submitted a copy of its regulations as an attachment to its comments.

K.7. Does the current lack of Federal standards and preemption provisions in Federal law preclude effective regulation of underground storage facilities by States?

1. INGAA, supported by several of its member companies, noted that jurisdiction over gas storage facilities in interstate pipeline systems is federal.

2. AGA and several of its pipeline operator members suggested that federal standards could assure a degree of consistency, and uniform standards would promote integrity and safety. AGA opined that implementation of federal standards could be delegated to the states.

3. GPTC and Nicor opined that federal regulations are not needed; as states are not now precluded from regulating gas storage and many do so.

4. The Texas Pipeline Association, the Texas Oil & Gas Association, Atmos, Ameren Illinois, and Northern Natural Gas opined that effective state regulation is not now precluded. The commenters stated that state regulation in combination with applicable FERC and DOT requirements has been demonstrated to assure safety successfully.

5. The Kansas Department of Health and Environment and the Kansas Corporation Commission noted that state regulation of the safety of interstate gas storage facilities is currently precluded. When Kansas attempted to enforce its requirements following an accident at an interstate storage facility, it was prevented from doing so by a federal court on the basis of federal preemption. The agencies noted that lack of action by PHMSA or FERC on interstate gas storage facility safety precludes states from taking any action and leaves these facilities essentially unregulated.

K.8. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

Response to All Topic K Comments

Since the publication of the ANPRM and the close of its comment period, Southern California Gas Company's (SoCal Gas) Aliso Canyon Natural Gas Storage Facility Well SS25 failed, causing a sustained and uncontrolled natural gas leak near Los Angeles, California. The failure, possibly from the downhole well casing, resulted in the relocation of more than 4,400 families according to the Aliso Canyon Incident Command briefing report issued on February 1, 2016. On January 6, 2016, California Governor Jerry Brown issued a proclamation declaring the Aliso Canyon incident a state emergency. On February 5, 2016, PHMSA issued an advisory bulletin in the **Federal Register** (81 FR 6334) to remind all owners and operators of underground storage facilities used for the storage of natural gas to consider the overall integrity of the facilities to ensure the safety of the public and operating personnel and to protect the environment. The advisory bulletin specifically reminded these operators to review their operations and identify the potential of facility leaks and failures, review the operation of their shut-off and isolation systems, and maintain updated emergency plans. In addition, PHMSA used the advisory bulletin to advocate the review of a previous advisory bulletin (97–04) dated July 10, 1997 and the voluntary implementation of American Petroleum Institute (API) 1170 ''Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage, First Edition, July 2015,'' API RP 1171 ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, First Edition, September 2015,'' and Interstate Oil and Gas Compact Commission (IOGCC) standards entitled ''Natural Gas Storage in Salt Caverns—A Guide for State Regulators'' (IOGCC Guide), as applicable. PHMSA will consider proposing a separate rulemaking to address the safety of underground natural gas storage facilities. Proposing a separate rulemaking that specifically focuses on improving the safety of underground natural gas storage facilities will allow PHMSA to fully consider the impacts of incidents that have occurred since the close of the initial comment period. It will also allow the Agency to consider voluntary consensus standards that were developed after the close of the comment period for this ANPRM, and to solicit feedback from additional stakeholders and members of the public to inform the development of potential regulations.

L. Management of Change

The ANPRM requested comments regarding the addition of requirements for the management of change to provide a greater degree of control over this element of pipeline risk, particularly following changes to physical configuration or operational practices. Operation of a pipeline over an extended period without effective management of change, such as changes to pipeline systems (*e.g.,* pipeline equipment, computer equipment or software used to monitor and control the pipeline) or to practices used to construct, operate, and maintain those systems, can result in safety issues. Changes can introduce unintended consequences if the change is not well thought out or is implemented in a manner not consistent with its design or planning. Similarly, changes in procedures require people to perform new or different actions, and failure to train them properly and in a timely

manner can result in unexpected consequences. The result can be a situation in which risk or the likelihood of an accident is increased. A recently completed but poorly-designed modification to the pipeline system was a factor contributing to the Olympic Pipeline accident in Bellingham, Washington. The following are general comments received related to this topic as well as comments related to the specific questions:

General Comments for Topic L

1. INGAA and several of its pipeline operator members disagreed with the implication in the ANPRM that change management is not now addressed in regulations. They pointed out that § 192.911(k) and ASME/ANSI B31.8S (incorporated by reference) already address this subject. INGAA reported that its members are committed to clarifying and expanding the use of a formal ''management of change'' process, and to facilitating its consistent application as a key management system. INGAA expressed its belief that the full adoption of ASME/ANSI B31.8S will facilitate the widespread application of these principles. Dominion East Ohio Gas also noted that part 192 already contains a management of change process. In addition, Chevron noted that management of change programs are generally specific to the organizational, operational, and ownership structures of the company, and part 192 already addresses this subject.

2. A private citizen opined that management of change is necessarily an integral part of quality management systems and another private citizen supported management of change requirements, noting that accidents often result from changes to systems. The Alaska Department of Natural Resources also supported PHMSA's goal of establishing management of change requirements or guidelines.

Response to General Comments for Topic L

PHMSA appreciates the information provided by the commenters. PHMSA agrees management of change is currently addressed in § 192.911(k). However, because of its importance, and consistent with INGAA members' commitment to expanding use of formal MOC processes, PHMSA believes it is prudent to provide greater emphasis on MOC directly within the rule text.

Therefore, PHMSA proposes to clarify integrity management requirements for management of change by explicitly including aspects of an effective management of change process into the rule text to emphasize the current requirements. In addition, PHMSA also proposes to add a new subsection 192.13(d) that would apply to onshore gas transmission pipelines, and require that an evaluation must be performed to evaluate and mitigate, as necessary, the risk to the public and environment as an integral part of managing pipeline design, construction, operation, maintenance and integrity, including management of change. The new paragraph would also articulate the general requirements for a management of change process, consistent with Section 192.911(k).

Comments submitted for questions in Topic L.

L.1. Are there standards used by the pipeline industry to guide management processes including management of change? Do standards governing the management of change process include requirements for IM procedures, O&M manuals, facility drawings, emergency response plans and procedures, and documents required to be maintained for the life of the pipeline?

1. AGA, supported by several of its members, and several transmission pipeline operators questioned why this question was in the ANPRM, noting that management of change requirements are already promulgated in § 192.911(k). GPTC added that § 192.909 also addresses this subject.

2. INGAA reported that Section 11 of ASME/ANSI B31.8S is the industry standard in this area, and all of the considerations in this question are included in operators' management of change processes. Several pipeline operators supported this comment.

3. Atmos reported that it is not aware of any standards used by the industry to guide management of change processes. Atmos does not have a formal management of change process, except in its integrity management program, but expressed its conclusion that existing practices within the company contribute to its ability to manage change.

4. Texas Pipeline Association (TPA) reported that its members do not have formal management of change processes but comply with regulations that address proxy requirements (*e.g.,* § 192.911). TPA expressed its belief that part 192, taken as a whole, includes management of change requirements to which its members adhere. Texas Oil & Gas Association supported TPA's comments.

5. California Public Utilities Commission reported that it is unaware of any pipeline industry standards in this area.

6. An anonymous commenter opined that most operators do not have management of change processes.

7. The NTSB recommended that PHMSA require operators of natural gas transmission and distribution pipelines and hazardous liquid pipelines to ensure that their control room operators immediately notify the relevant 911 emergency call centers of possible ruptures (Recommendation P–11–9).

8. TransCanada reported that it is committed to clarifying and expanding the use of a formal ''management of change'' process. TransCanada expressed its conclusion that the full adoption of ASME/ANSI B31.8S will facilitate the widespread application of management of change principles.

Response to Question L.1 Comments

PHMSA appreciates the information provided by the commenters, which did not identify any standards beyond ASME/ANSI B31.8S, which is already invoked by part 192, and used by the pipeline industry to guide management processes including management of change. See response to the general comments for Topic L, above.

L.2. Are standards used in other industries (e.g., Occupational Safety and Health Administration standards at 29 CFR 1910.119) appropriate for use in the pipeline industry?

1. INGAA reported that Section 11 of ASME/ANSI B31.8S is based on OSHA's Process Safety Management (PSM) standards. INGAA noted that OSHA worked with industry in developing PSM standards that would identify potential threats and assure that mitigative actions were taken. Several pipeline operators supported INGAA's comments.

2. AGA and GPTC expressed their belief that there is no benefit in comparing standards with other industries, reiterating that §§ 192.909 and 192.911 and ASME/ANSI B31.8S already include management of change. Several pipeline operators supported AGA's comments.

3. The Texas Pipeline Association and the Texas Oil & Gas Association reported that their members are aware of standards used in other industries but do not believe they are appropriate or applicable to the pipeline industry.

4. The Iowa Association of Municipal Utilities expressed its conclusion that OSHA standards are complicated and would be unduly costly for small municipal utilities.

5. Accufacts noted that transportation pipelines are specifically excluded from OSHA regulation; however, this does not prevent PHMSA from incorporating elements of 29 CFR 1910.119 into the

federal pipeline safety regulations in order to mandate a more prudent pipeline safety culture.

6. Atmos reported that it has no experience with standards used in other industries but noted that OSHA standards appear to be directed toward situations where processes interact such that a change in one process affects a second or third process.

7. Ameren Illinois suggested that standards from other industries would need to be studied to determine if they are applicable to the pipeline industry.

8. An anonymous commenter suggested that the OSHA standards are a good model for pipelines, as they are well written and thought out.

Response to Question L.2 Comments

PHMSA appreciates the information provided by the commenters. See response to the general comments for Topic L, above.

L.3. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

M. Quality Management Systems (QMS)

The ANPRM requested comments on whether and how to impose requirements related to quality management systems. Quality management includes the activities and processes that an organization uses to achieve quality. These include formulating policy, setting objectives, planning, quality control, quality assurance, performance monitoring, and quality improvement.

Achieving quality is critical to gas transmission pipeline design, construction, and operations. PHMSA recognizes that pipeline operators strive to achieve quality, but our experience has shown varying degrees of success in accomplishing this objective among pipeline operators. PHMSA believes that an ordered and structured approach to quality management can help pipeline operators achieve a more consistent state of quality and thus improve pipeline safety.

PHMSA's pipeline safety regulations do not currently address process management issues such as quality management systems. Section 192.328 requires a quality assurance plan for the construction of pipelines intended to operate at an alternative MAOP, but there is no similar requirement applicable to other pipelines. Quality assurance is generally considered to be an element of quality management. Important elements of quality management systems are their design and application to control (1) the equipment and materials used in new construction (*e.g.,* quality verification of materials used in construction and replacement, post-installation quality verification), and (2) the contractor work product used to construct, operate, and maintain the pipeline system (*e.g.,* contractor qualifications, verification of the quality of contractor work products).

The ANPRM then listed questions for consideration and comment. The following are general comments received related to this topic as well as comments related to the specific questions:

General Comments for Topic M

1. MidAmerican suggested that PHMSA work with the committees for ASME/ANSI B31.8 and B31.8S to address these topics more fully, if PHMSA believes more is needed. MidAmerican opined that a general rule addressing quality management systems would divert resources and adversely affect safety, if applied to this already heavily-regulated industry.

2. The Alaska Department of Natural Resources supported quality management systems and suggested that pipeline operators should apply such standards to their contractors.

3. A private citizen supported quality management systems, noting that this is an area that would be difficult to regulate but might be an element in incentive programs.

Comments submitted for questions in Topic M.

M.1. What standards and practices are used within the pipeline industry to assure quality? Do gas transmission pipeline operators have formal QMS?

1. INGAA opined that achieving consistent quality materials, construction and management is an appropriate focus for the INGAA Foundation, which has sponsored and will continue to sponsor workshops on this subject. INGAA reported that the Foundation plans to publish five relevant White Papers in 2012 and its Integrity Management—Continuous Improvement team is currently working on guidelines. INGAA also noted that there are elements of a quality management system in ASME/ANSI B31.8S, already incorporated by reference, including quality assurance/quality control, management of change, communication and performance measurement, Standards, specifications, and procedures governing pipe and appurtenances form part of a pipeline quality management system. INGAA cited ISO (9001:2008/29001:2010) and API (Spec Q1) quality management standards as references that are available for operator use. INGAA further noted that API published Spec Q2 in December 2011. Several pipeline operators supported INGAA's comments.

2. AGA, GPTC, Nicor, Atmos, the Texas Pipeline Association, and the Texas Oil & Gas Association suggested that part 192, taken as a whole, is essentially a quality management system. AGA provided a summary listing of part 192 requirements that assure quality. A number of additional pipeline operators supported AGA's comments.

3. Ameren Illinois reported that it has a quality assurance program for pipeline construction that includes building alliances with excavators and other elements.

4. Paiute and Southwest Gas reported that their practices beyond compliance with part 192 requirements include operator qualification (OQ) for construction, an internal quality assurance group, root cause analysis of events, and quality control verification of OQ.

5. MidAmerican reported that it has no formal quality management system but applies standards to assure quality processes. In particular, ASME/ANSI B31.8 and B31.8S and ANSI/ISO/ASQ Q9004–2000 were used to guide its company quality programs. MidAmerican also has a contractor oversight program.

6. An anonymous commenter opined that most operators have a quality management system, often incorporated into their SCADA system, to satisfy customers or end user requirements. The commenter suggested that some of these systems have only recently been modified to address internal corrosion mechanisms, often identified as part of operators' integrity management programs.

M.2. Should PHMSA establish requirements for QMS? If so, why? If so, should these requirements apply to all gas transmission pipelines and to the complete life cycle of a pipeline system?

1. INGAA, supported by a number of its pipeline operator members, asserted that no new requirements are appropriate at this time. INGAA noted that much work is ongoing in this area and it may be appropriate to adopt some standards (*e.g.,* API Q1 or Q2) in the future.

2. AGA, GPTC, the Texas Pipeline Association, the Texas Oil & Gas Association, Oleksa and Associates, and numerous pipeline operators expressed an opinion that new quality assurance requirements are not needed. These commenters view part 192 as quality assurance requirements and argue that a new programmatic requirement would not be beneficial.

3. TransCanada opined that quality management systems need to be adopted throughout the entire industry and embraced by operators and contractors alike, arguing that this would provide a more consistent level of quality throughout the industry. TransCanada opined that the INGAA Foundation is the appropriate venue in which to develop guidelines.

4. Northern Natural Gas opined that the existing process, which includes PHMSA/State inspections, is adequate.

5. A private citizen commented that quality management systems should be required to improve pipeline safety, including documentation, investigations, validation, audits/inspections, change management, training, and quality/management oversight.

6. An anonymous commenter opined that no new requirements are needed, arguing that most operators have such systems.

M.3. Do gas transmission pipeline operators require their construction contractors to maintain and use formal QMS? Are contractor personnel that construct new or replacement pipelines and related facilities already required to read and understand the specifications and to participate in skills training prior to performing the work?

1. INGAA reported that most of its members apply quality management principles, including requiring contractors conform to specified requirements, though the approach varies from operator to operator. INGAA acknowledged, however, that ''[t]here is room to establish a more structured approach to QMS for operators and construction contractors'' to assure more consistency. A number of pipeline operators supported INGAA's comments.

2. AGA reported that transmission operators have the means to assure contractor work quality and that most LDC operators impose operator qualification (OQ) and other specific requirements on their construction contractors.

3. The Texas Pipeline Association and the Texas Oil & Gas Association encouraged PHMSA not to adopt requirements for operators to train construction personnel. The associations expressed concerns over potential liability and their preference for a performance-based standard.

4. Ameren Illinois, Atmos, and MidAmerican reported that they apply operator qualification (OQ) requirements on their contractors.

5. Northern Natural Gas, Paiute, and Southwest Gas reported that they do not require contractors to have formal QMS but do require conformance to various standards.

6. Oleksa and Associates reported its experience that operators require construction contractors to meet the same standards as their employees.

7. GPTC, Nicor, and an anonymous commenter suggested that compliance with construction regulations contribute to QMS through requirements for specifications and inspections.

8. NAPSR, the Texas Pipeline Association, and the Texas Oil & Gas Association suggested that operator qualification (OQ) requirements be applied to construction, since this would apply formal QMS to the full range of construction and operation.

M.4. Are there any standards that exist that PHMSA could adopt or from which PHMSA could adapt concepts for QMS?

1. INGAA and a number of pipeline operators suggested that several standards could be used as general references, including ISO 9001:2008 (Quality Management Systems), ISO 29001:2010 (Oil and Gas) and API Spec Q1 (Oil and Gas). INGAA opined that compliance with these standards should not be required, and added that additional standards, white papers, and guidance are under development.

2. The AGA, GPTC, Nicor, and Ameren Illinois opposed new requirements in this area. AGA opined that part 192 is already ''saturated'' with this type of requirement. A number of additional pipeline operators supported AGA's comments.

3. The NTSB recommended improvement to PHMSA's drug and alcohol requirements, citing their recommendations P–11–12 & 13.

4. A private citizen suggested that, by extrapolating from the practices of a pipeline operator with a good safety record. The commenter stated that useful references include the Baldrige Performance Excellence Program and Quality Management Standard ISO 9000.

M.5. What has been the impact on cost and safety in other industries in which requirements for a QMS have been mandated?

1. INGAA reported that quality management systems have been demonstrated to reduce risk and opined that the keys to a successful QMS are simplicity, empowerment, accountability and ease of implementation. A number of pipeline operators supported INGAA's comments.

M.6. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

Response to All Topic M Comments

PHMSA appreciates the information provided by the commenters. PHMSA does not propose additional rulemaking for this topic at this time. PHMSA will review the comments received on the ANPRM and will consider them in future rulemaking.

N. Exemption of Facilities Installed Prior to the Regulations

The ANPRM requested comments regarding proposed changes to part 192 regulations that would eliminate provisions that exempt pipelines from pressure test requirements to establish MAOP. Federal pipeline safety regulations were first established with the initial publication of part 192 on August 19, 1970 (35 FR 13248). Gas transmission pipelines had existed for many years prior to this, some dating to as early as 1920. Many of these older pipelines had operated safely for years at pressures higher than would have been allowed under the new regulations. It was concluded that a required reduction in the operating pressure of these pipelines would not have resulted in a material increase in safety. Therefore, a provision was included in the regulations (§ 192.619(c)) that allowed pipelines to

operate at the highest actual operating pressure to which they were subjected during the 5 years prior to July 1, 1970. The safe operation of these pipelines at these pressures was deemed to be evidence that operation could safely continue.

Many gas transmission pipelines continue to operate in the United States under an MAOP established in accordance with § 192.619(c). Some of these pipelines operate at stress levels higher than 72 percent specified minimum yield strength (SMYS), the highest level generally allowed for more modern gas transmission pipelines. Some pipelines operate at greater than 80 percent SMYS, the alternate MAOP allowed for some pipelines by regulations adopted October 17, 2008 (72 FR 62148). Under these regulations, operators who seek to operate their pipelines at up to 80 percent SMYS (in Class 1 locations) voluntarily accept significant additional requirements applicable to design, construction, and operation of their pipeline that are intended to assure quality and safety at these higher operating stresses. Pipelines that operate under an MAOP established in accordance with § 192.619(c) are subject to none of these additional requirements.

Part 192 also includes several provisions other than establishment of MAOP for which an accommodation was made in the initial part 192. These provisions allowed pipeline operators to use steel pipe that had been manufactured before 1970 and did not meet all requirements applicable to pipe manufactured after part 192 became effective (192.55); valves, fittings and components that did not contain all the markings required (192.63); and pipe which had not been transported under the standard included in the new part 192 (192.65, subject to additional testing requirements).

The ANPRM then listed questions for consideration and comment. The following are general comments received related to this topic as well as comments related to the specific questions:

General Comments for Topic N

1. INGAA and a number of pipeline operators opined that age alone is not an appropriate criterion for determining a pipeline's fitness for service. Old pipe that is well maintained operates safely and unfit pipe should be replaced regardless of age. INGAA suggested that fitness for service of pipe in HCAs should be evaluated using available records, if adequate, or through new testing. INGAA attached a white paper to its comments that described its Fitness for Service protocol. INGAA also cautioned that any requirement to reconfirm MAOP should be subject to a rigorous cost-benefit analysis, as hydrostatic testing is very expensive and could require outages of up to several weeks.

2. A private citizen suggested phasing out sub-standard or systems that pre-date regulatory requirements where public safety is concerned, implying that this has been done in other areas (citing elimination of radium dial watches and leaking underground storage tanks as examples).

3. A private citizen suggested that legacy facilities should be subject to a timetable to come into full compliance with current regulations, arguing that this would improve safety and knowledge of older facilities.

Response to General Comments for Topic N

PHMSA appreciates the information provided by the commenters. NTSB recommended that regulatory exemptions be repealed. In addition, section 23 of the Act addressed gas transmission pipelines without records sufficient to validate MAOP. In response to these concerns, this NPRM proposes requirements for verification of maximum allowable operating pressure (MAOP) in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Verification of MAOP includes establishing and documenting MAOP if the pipeline MAOP was established in accordance with § 192.619(c), the grandfather clause. In addition, this NPRM proposes requirements for verification of pipeline material in accordance with new § 192.607 for existing onshore, steel, gas transmission pipelines that are located in an HCA or class 3 or class 4 locations.

Comments Submitted for Questions in Topic N

N.1. Should PHMSA repeal provisions in part 192 that allow use of materials manufactured prior to 1970 and that do not otherwise meet all requirements in part 192?

1. INGAA, supported by several pipeline operators, suggested age, alone, should not be a criterion for determining fitness for service, noting some pre-regulation materials (*e.g.,* seamless pipe) are as good as today's.

2. AGA, GPTC, and numerous pipeline operators noted it is illogical to storehouse pre-1970 materials for installation now. AGA indicated that it thus did not understand the purpose of the ANPRM question.

3. Iowa Utilities Board, NAPSR, Texas Pipeline Association, Texas Oil & Gas Association, Accufacts, Alaska Department of Natural Resources, Atmos, Commissioners of Wyoming County Pennsylvania, Professional Engineers in California Government, and an anonymous commenter encouraged repeal of this allowance. Some of these commenters would allow a specified time period for operators to come into compliance.

4. Thomas Lael and MidAmerican recommended operators be allowed to continue use of materials that have already been placed into service, arguing that they have been demonstrated safe through integrity management.

5. Ameren Illinois and Northern Natural Gas opposed repeal of this provision.

Response to Question N.1 Comments

PHMSA appreciates the information provided by the commenters. As stated above, this NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). In addition, this NPRM proposes requirements for verification of pipeline material in accordance with new § 192.607 for existing onshore, steel, gas transmission pipelines that are located in an HCA or class 3 or class 4 locations.

N.2. Should PHMSA repeal the MAOP exemption for pre-1970 pipelines? Should pre-1970 pipelines that operate above 72% SMYS be allowed to continue to be operated at these levels without increased safety evaluations such as periodic pressure tests, in-line inspections, coating examination, CP surveys, and expanded requirements on interference currents and depth of cover maintenance?

1. INGAA and a number of pipeline operators opposed repeal of this exemption. INGAA suggested its Fitness for Service protocol be used to assure continued safety of old pipe.

2. AGA, GPTC, Texas Pipeline Association, Texas Oil & Gas Association and numerous pipeline operators commented that the wording of this question creates a false impression. There is no exemption for MAOP. Rather, the regulations establish requirements for determining MAOP and the only ''exemption'' is to a post-construction hydrostatic test, since the pipeline was in service at the time the regulations became effective.

3. AGA, supported by several of its pipeline operator members, contended the appropriate method for verifying

MAOP of older pipelines is for PHMSA to follow Section 23 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. AGA opposed eliminating § 192.619(c) for determining MAOP of older pipelines, arguing that it would cripple the nation's gas pipeline capacity. A number of additional pipeline operators joined AGA in opposing any new requirement to pressure test all older pipelines, arguing costs would be excessive and there would be significant potential to interrupt gas services. AGA included a white paper with its comments outlining its suggested approach to MAOP verification.

4. Accufacts, Texas Pipeline Association, and Texas Oil & Gas Association opposed requiring all pre-1970 pipelines to reduce MAOP, if necessary, to a pressure that would impose stresses no greater than 72 percent SMYS. Accufacts noted this pipe is still safe at its current operating pressure if it is managed properly, but suggested a possible focus on interactive threats that might make seam welds unstable.

5. Ameren Illinois opposed modifying MAOP requirements for pre-1970 pipelines.

6. NAPSR, the NTSB, and Professional Engineers in California Government supported repeal of exemptions applying to MAOP of pre-1970 pipelines. NAPSR added PHMSA should not allow any pipeline to operate at pressures above that which would impose stresses greater than 72 percent SMYS.

7. MidAmerican suggested use of a performance-based approach, which might include a fitness for service determination for pipe in Class 2, 3, or 4 areas or HCA.

8. Commissioners of Wyoming County Pennsylvania would support repeal of MAOP exemptions because pipeline infrastructure is aging and they see additional safety measures needed.

Response to Question N.2 Comments

PHMSA appreciates the information provided by the commenters. As stated above, this NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Verification of MAOP includes establishing and documenting MAOP if the pipeline segment: (1) Has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''); (2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; or (ii) a class 3 or class 4 location; or (3) the pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before *[effective date of rule]* and is located in one of the following areas:

(i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

N.3. Should PHMSA take any other actions with respect to exempt pipelines? Should pipelines that have not been pressure tested in accordance with subpart J be required to be pressure tested in accordance with present regulations?

1. AGA and a number of pipeline operators opposed any requirement to pressure test all pipelines that have not been tested in accordance with subpart J, arguing Congress considered and rejected this approach in developing the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The commenters argue such a requirement would cripple the pipeline industry and support the alternative requirements included in the Act.

2. MidAmerican suggests a focus on pipe in Class 3 or 4 areas or HCAs. The company suggests no new requirements are needed if records are complete for pipe in these areas or it has been tested to 1.25 times MAOP. Otherwise, MidAmerican would subject such pipelines to a fitness for service determination.

3. The NTSB would require all pre-1970 pipelines to be pressure tested, including a spike test, citing their recommendation P–11–14.

4. Texas Pipeline Association and Texas Oil & Gas Association opposed a requirement to test all pipelines not previously subject to subpart J tests, arguing testing per the construction codes in effect when the pipelines were constructed and safe operating experience since then is adequate assurance of suitability.

5. Ameren Illinois reported the State of Illinois imposed pressure testing requirements before federal pipeline safety regulations were adopted in 1970.

6. Iowa Utilities Board and Iowa Association of Municipal Utilities recommended any new pressure test requirement be limited to pipeline segments in HCA and which operate at pressures where a rupture could occur (generally greater than 30 percent SMYS). These commenters argued the serious impacts of service interruptions pressure testing would be necessary for testing have not been appreciated and the cost for such testing of other pipelines would be unjustified absent any specific demonstration of risk.

7. Commissioners of Wyoming County Pennsylvania and Professional Engineers in California Government (PECG) would require pressure testing for pipelines not previously tested to subpart J requirements, since this would assure public safety. PECG would also require testing if adequate records of prior tests do not exist, noting California has experienced two failures to date of pipeline not adequately tested. PECG would also require all testing, modification, and replacement be observed by a certified inspector loyal to public safety interests.

8. An anonymous commenter would require subpart J testing but would allow schedule flexibility.

Response to Question N.3 Comments

PHMSA appreciates the information provided by the commenters. This NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3). Verification of MAOP includes establishing and documenting MAOP using one or more of the methods in 192.624(c)(1) through (c)(6). In addition, this NPRM proposes requirements for verification of pipeline material in new § 192.607 for existing onshore, steel, gas transmission pipelines that are located in an HCA or class 3 or class 4 locations.

N.4. If a pipeline has pipe with a vintage history of systemic integrity issues in areas such as longitudinal

weld seams or steel quality, and has not been pressure tested at or above 1.1 times MAOP or class location test criteria (§§ 192.505, 192.619 and 192.620), should this pipeline be required to be pressure tested in accordance with present regulations?

1. AGA and several pipeline operators opposed requiring hydrostatic tests for systemic issues, arguing it could potentially affect all pipelines. AGA noted Congress had considered and rejected this approach in developing the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. AGA supports the requirements in Section 23 of the Act. AGA further argued hold times in subpart J are excessive since defects that fail will likely do so in the first 30 minutes and urged PHMSA not to require any special testing for pipelines operating at less than 30 percent SMYS since they are likely to fail by leakage rather than rupture.

2. GPTC and Nicor opposed a blanket requirement for hydrostatic testing. They would test only in event of a demonstrated safety issue and only if a risk evaluation indicates testing is appropriate. For distribution operators, these commenters would treat any safety issues in distribution integrity management programs.

3. Atmos would not require pressure testing for systemic issues, arguing these are addressed adequately by subpart O.

4. Accufacts would require testing, focusing first on pipe in HCAs, at pressures greater than 1.1 times MAOP. Accufacts understands some operators are arguing for a 1.1 x MAOP test pressure and considers that to be insufficient.

5. MidAmerican would allow a risk-based alternative approach for problem pipe.

6. Texas Pipeline Association and Texas Oil & Gas Association would require assessments appropriate to a specific threat rather than a blanket requirement for pressure testing.

7. An anonymous commenter supported pressure testing for pipe subject to systemic issues.

Response to Question N.4 Comments

PHMSA appreciates the information provided by the commenters. This NPRM proposes requirements for verification of MAOP in new § 192.624 for onshore, steel, gas transmission pipelines that are located in an HCA or MCA and meet any of the conditions in § 192.624(a)(1) through (a)(3).

N.5. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

O. Modifying the Regulation of Gas Gathering Lines

The ANPRM requested comments regarding modifying the regulations relative to gas gathering lines. In March 2006, PHMSA issued new safety requirements for ''regulated onshore gathering lines.'' [38] Those requirements established a new method for determining if a pipeline is an onshore gathering line, divided regulated onshore gas gathering lines into two risk-based categories (Type A and Type B), and subjected such lines to certain safety standards.

The 2006 rule defined onshore gas gathering lines based on the provisions in American Petroleum Institute Recommended Practice 80, ''Guidelines for the Definition of Onshore Gas Gathering Lines,'' (API RP 80), a consensus industry standard incorporated by reference. Additional regulatory requirements for determining the beginning and endpoints of gathering, modifying the application of API RP 80, were also imposed to improve clarity and consistency in their application.

In practice, however, the use of API RP 80, even as modified by the additional regulations, is difficult for operators to apply consistently to complex gathering system configurations. Enforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system, which can lead to the potential misapplication of the incidental gathering line designation under that standard. In addition, recent developments in the field of gas exploration and production, such as shale gas, indicate that the existing framework for regulating gas gathering lines may need to be expanded. Gathering lines are being constructed to transport ''shale'' gas that range from 4 to 36 inches in diameter with MAOPs up to 1480 psig, far exceeding the historical operating parameters (pressure and diameter). The risks considered during the development of the 2006 rule did not foresee gathering lines of these diameters and pressures.

Currently, according to 2011 annual reports submitted by pipeline operators, PHMSA only regulates about 8845 miles of Type A gathering lines, 5178 miles of Type B gathering lines, and about 6258 miles of offshore gathering lines, for a total of approximately 20,281 miles of regulated gas gathering pipelines. Gas gathering lines are currently not regulated if they are in Class 1 locations. Current estimates also indicate that there are approximately 132,500 miles of Type A gas gathering lines located in Class 1 areas (of which approximately 61,000 miles are estimated to be 8-inch diameter or greater), and approximately 106,000 miles of Type B gas gathering lines located in Class 1 areas. Also, there are approximately 2,300 miles of Type B gas gathering lines located in Class 2 areas, some of which may not be regulated in accordance with § 192.8(b)(2).

The ANPRM then listed questions for consideration and comment. The following are general comments received related to this topic as well as comments related to the specific questions:

General Comments for Topic O

1. Gas Processors Association (GPA) recommended PHMSA complete the study required by Section 21 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 before proposing any substantive regulations regarding gathering lines. The Association sees this as an essential pre-requisite and indicated it would establish a working group to work with PHMSA on the study. Following the study, GPA would then have PHMSA begin any rulemaking process with another ANPRM, focused on the issues to be addressed in changing regulation of gathering lines. Independent Petroleum Association of America, American Petroleum Institute, Oklahoma Independent Petroleum Association, and Chevron agreed any change to gathering line regulations before the required report to Congress would be inconsistent with the Act.

2. Independent Petroleum Association of America, American Petroleum Institute, Oklahoma Independent Petroleum Association, and Chevron argued no change in the gathering line regulatory regime is justified. IPAA and API argued gathering lines can be regulated based only on actual, vs.

[38] 71 FR 13289 (March 15, 2006).

speculative, risk, and that any change without such demonstrated risk would be arbitrary, capricious, and contrary to law.

3. Atmos would require new gathering lines operating above 20 percent SMYS to meet requirements in § 192.9(c), and those below 20 percent SMYS § 192.9(d). These paragraphs are, respectively, requirements applicable to Type A and Type B gathering lines. The ''type'' of a gathering line is established in accordance with requirements in § 192.8, and is based on the pipe material and MAOP of the line. Atmos argued, however, that class location changes over time and determining applicable requirements for new gathering lines based on stress levels would provide for public safety without the problems or confusion that could result from subsequent class location changes.

4. Texas Pipeline Association and Texas Oil & Gas Association suggested PHMSA treat gathering lines under a separate docket and collect data under the current regulatory regime before making any changes. The associations suggested a delay in rulemaking of 3 to 5 years to accumulate data from recently-promulgated changes in reporting requirements. The associations argued changes made without gathering and reviewing that data could be found unnecessary and would divert resources from higher risk needs. Atmos agreed any rulemaking concerning gathering lines should be conducted under a separate docket due to the complexity of the issues involved.

5. Dominion East Ohio Gas argued it is too soon for wholesale changes to the new federal regulations applicable to gas gathering lines. The company suggested one proposed change would be to consider ''Incidental Gathering'' as defined in API RP 80.

6. NAPSR and Commissioners of Wyoming County Pennsylvania suggested PHMSA assert regulatory authority beginning at the wellhead or first metering point. They argued the regulatory gap that results from excluding production facilities from regulation produces risks, especially in areas where high-pressure wells are being drilled in urban areas. NAPSR further stated that PHMSA should consider short sections of pipeline downstream of processing, compression, and similar equipment to be a continuation of gathering. The functional name of a segment of pipeline is not important, *i.e.,* production, gathering, transmission. All pipelines should be treated the same in terms of safety from the well head to the city gate.

7. Commissioners of Wyoming County Pennsylvania recommended PHMSA regulate gathering lines in Class 1 areas. The Commissioners noted many new gathering lines, some operating at high pressures, are being constructed in Class 1 areas of the Marcellus Shale Region, and regulation of these lines is necessary to ensure public safety. The Commissioners noted Pennsylvania law gives the state's public utilities commission authority to regulate pipelines but requires that they be no more stringent than federal regulations.

8. The League of Women Voters of Pennsylvania would regulate gathering lines in the same manner as transmission and would further require that gas in pipelines of both types be odorized.

9. Pipeline Safety Trust would have PHMSA assure gathering lines are displayed on the National Pipeline Mapping System.

Response to General Comments for Topic O

PHMSA appreciates the information provided by the commenters. The commenters are correct that the Act required several actions related to gas gathering lines including a requirement that a study to be conducted prior to issuing new rules. We would note, however, that PHMSA is only proceeding with the issuance of an NPRM proposing expanded requirements and needed clarity with regard to issues that had been identified prior to enactment of the Act. The study has been completed and submitted to Congress and placed on the docket. PHMSA invites public comment on the study, which will inform the final rule. In addition, recent developments in the field of gas exploration and production, such as shale gas, indicate that the existing framework for regulating gas gathering lines may need to be expanded. Gathering lines are being constructed to transport ''shale'' gas that range from 4 to 36 inches in diameter with MAOPs up to 1,480 psig, far exceeding the historical operating parameters of such lines.

Currently, according to 2011 annual reports submitted by pipeline operators, PHMSA only regulates about 8845 miles of Type A gathering lines, 5,178 miles of Type B gathering lines, and about 6,258 miles of offshore gathering lines, for a total of approximately 20,281 miles of regulated gas gathering pipelines. Gas gathering lines are currently not regulated if they are in Class 1 locations. Current estimates also indicate that there are approximately 132,500 miles of Type A gas gathering lines located in Class 1 areas, and approximately 106,000 miles of Type B gas gathering lines located in Class 1 areas. Also, there are approximately 2,300 miles of Type B gas gathering lines located in Class 2 areas, some of which may not be regulated in accordance with § 192.8(b)(2).

Moreover, enforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system because numerous factors are involved, including the locations of treatment facilities, processing plants, and compressors, the relative spacing of production fields, and the commingling of gas. This can lead to the potential misapplication of the incidental gathering line designation under that standard.

In this NPRM, PHMSA proposes to extend existing requirements for Type B gathering lines to Type A gathering lines in Class 1 locations, if the nominal diameter is 8'' or greater.

Comments submitted for questions in Topic O.

O.1. Should PHMSA amend 49 CFR part 191 to require the submission of annual, incident, and safety-related conditions reports by the operators of all gathering lines?

1. AGA, GPTC, Texas Pipeline Association, Texas Oil & Gas Association, and several pipeline operators opposed requiring annual reports for unregulated gas gathering pipelines, arguing such a requirement would be unduly burdensome with no safety benefit. These commenters agreed incident reports for unregulated gathering lines could be useful as a means to determine the effectiveness of safety practices on these pipelines.

2. Gas Producers Association opposed expanding reporting requirements to Class 1 gathering pipelines. The Association noted gathering lines in other class locations are currently subject to reporting requirements and suggested there were other means for PHMSA to collect data on Class 1 lines without requiring burdensome reporting. In the specific case of safety-related condition reports, the Association argued requiring reporting is clearly premature, because the purpose of these reports is to highlight problems in which PHMSA may elect to become involved and PHMSA presently does not regulate these pipelines.

3. Texas Pipeline Association and Texas Oil & Gas Association would support requiring incidents to be reported for all gathering pipelines as a first step in collecting data to determine whether other changes are needed.

4. Atmos would support limited reporting for Class 1 gathering lines, to include incidents and total mileage.

5. NAPSR, Alaska Department of Natural Resources, Pipeline Safety Trust, and Commissioners of Wyoming County Pennsylvania would require operators of Class 1 gathering pipelines to submit reports, because these pipelines can affect public safety and should be held accountable.

Response to Question O.1 Comments

PHMSA appreciates the information provided by the commenters. The comments provide varied support for requiring submission of annual, incident, and safety-related conditions reports by the operators of all gathering lines. PHMSA believes these reports would provide valuable information, combined with the results of the congressionally required study, to support evaluation of the effectiveness of safety practices on these pipelines and determination of any needed additional requirements beyond those proposed in this NPRM. Accordingly, PHMSA proposes to delete the exemption for reporting requirements for operators of unregulated onshore gas gathering lines.

O.2. Should PHMSA amend 49 CFR part 192 to include a new definition for the term ''gathering line''?

1. AGA and several pipeline operators opposed a change to the definition of gathering lines, noting API RP–80, with restrictions as specified in current regulations, is a good working definition.

2. Independent Petroleum Association of America, American Petroleum Institute, Oklahoma Independent Petroleum Association, Atmos, and Chevron argued that API RP 80, as currently specified, is the appropriate means for defining gathering lines. They argued it is based on a pipeline's function rather than its location and changes could infringe on production facilities, regulation of which is precluded by statute.

3. Gas Processors Association opposed changing the definition of gathering line or extending regulation to lines in Class 1 areas. The Association noted excluding Class 1 lines from regulation is risk-based and expressed its interest in continuing the risk-based approach to regulation represented by the 2006 rule.

4. NAPSR, GPTC, Accufacts, Thomas Lael, and Nicor supported simplifying the definition of gathering lines. These commenters noted that API RP–80 is confusing. One commenter referred to its application as a ''nightmare.'' The definition in Texas regulations was suggested as one possible model.

5. Oklahoma Independent Petroleum Association strongly opposed changes to the definitions of gathering line or production facilities.

6. Texas Pipeline Association and Texas Oil & Gas Association would not change the definition of gathering lines at this time, arguing data gathering, a necessary first step, is not yet complete.

7. The State of Washington Citizens Advisory Committee and a private citizen urged changes to the definitions of gathering, transmission, and distribution pipelines, arguing that the current definitions are confusing and employ circular logic.

8. Pipeline Safety Trust would revise the definition of gathering in a manner that does not allow operators to choose whether their pipeline is gathering or not on the basis of where they decide to install equipment. PST noted there is significant overlap among pipeline types in size, operating pressure, and attendant risks.

9. Alaska Department of Natural Resources and Commissioners of Wyoming County Pennsylvania urged a revision to the definition of gathering lines, in light of shale gas development which, the commenters contended, produces risks approximately equivalent to those from transmission pipelines.

Response to Question O.2 Comments

PHMSA appreciates the information provided by the commenters. Industry commenters opposed a change to the definition of gathering lines, whereas NAPSR and other commenters supported revision of the definition of gathering lines and classified API RP–80 as confusing. As discussed above, PHMSA believes revision of the definition of gathering lines is needed and also proposes a new definition for onshore production facility/operation. In addition, see response to question O.3 comments.

O.3. Are there any difficulties in applying the definitions contained in RP 80? If so, please explain.

1. Independent Petroleum Association of America, American Petroleum Institute, Oklahoma Independent Petroleum Association, and Chevron were emphatic in declaring there are no difficulties in applying API RP–80. IPAA and API noted that significant difficulties among gathering lines made RP–80 difficult to develop.

2. AGA and a number of pipeline operators reported RP–80 is clear and there are no difficulties with its application.

3. Gas Processors Association would retain the RP–80 definition, at least until the study required by the Act is completed. GPA acknowledged that application of RP–80 has been difficult, but stated that it has been difficult to craft a simpler definition.

4. Texas Pipeline Association and Texas Oil & Gas Association reported application of RP–80 has been challenging. The associations opined this has resulted from complexities in gathering pipeline systems and confusion caused by PHMSA guidance and interpretations.

5. Accufacts, NAPSR, GPTC, and Nicor commented RP–80 is too complex, not understandable to the public, and subject to misuse by operators.

Response to Question O.3 Comments

PHMSA appreciates the information provided by the commenters. Industry commenters stated there are no difficulties in applying the definitions contained in API RP 80, whereas Accufacts, NAPSR and other commenters contend that API RP 80 is too complex, not understandable, and subject to misuse. PHMSA enforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, which is complex and can produce multiple classifications for the same pipeline system. In the 2006 rulemaking which incorporated by reference the API RP 80, PHMSA expressed reservations concerning the ability to effectively and consistently apply the document as written, echoing NAPSR's comments at the time. Additionally, in 2006, PHMSA imposed limiting regulatory language in part 192 in an attempt to curtail the potential for misapplication of the language contained in RP–80. These limitations and their intended application were discussed in great detail in the Supplemental Notice of Proposed Rulemaking [Docket No. RSPA–1998–4868; Notice 5]. Because of the ambiguous language and terminology in the RP–80, *e.g.* separators are defined for both production and gathering almost verbatim, experience has shown that facilities are being classified as production much further downstream than was ever intended. The application of ''incidental gathering'' as used in API RP–80 has not been applied as intended in some cases. Several recent interpretations letters have been issued by PHMSA on this topic including an expressed intent to clarify the issue in future rulemaking. Therefore, PHMSA believes revision of the definition of gathering lines is needed and proposes

deleting the use of API RP 80 as the basis for determining regulated gathering lines and would establish the new definition for onshore *production facility/operation* and a revised definition for *gathering line* as the basis for determining the beginning and endpoints of each gathering line.

O.4. Should PHMSA consider establishing a new, risk-based regime of safety requirements for large-diameter, high-pressure gas gathering lines in rural locations? If so, what requirements should be imposed?

1. Commissioners of Wyoming County Pennsylvania and 24 private citizens encouraged PHMSA to regulate gathering lines in Class 1 locations. The commenters noted many such pipelines will exist in shale gas areas, many of them large-diameter and operating at high pressures, and contended these pipelines currently are being ignored by federal and state regulators. They noted the pipeline that ruptured causing the San Bruno accident was operated at a pressure considerably lower than some gathering lines in shale gas areas.

2. AGA, GPTC, and a number of pipeline operators argued no new requirements are needed and the effectiveness of the 2006 changes to regulation needs to be reviewed first, in accordance with the Act.

3. Gas Processors Association, Texas Pipeline Association, and Texas Oil & Gas Association contended PHMSA must gather additional data on Class 1 gathering lines before deciding whether to regulate them, arguing that only a detailed study can determine whether new regulations are appropriate.

4. Oklahoma Independent Petroleum Association cautioned any regulatory change needs to be supported by science and a comprehensive cost-benefit analysis.

5. Independent Petroleum Association of America, American Petroleum Institute, Oklahoma Independent Petroleum Association, and Chevron argued any change in the regulatory regime for gathering lines is unjustified. The commenters contended such lines only operate at high pressures when new, that pressure decreases as wells deplete, and that the record shows these lines are safe.

6. A private citizen who operates an outdoor gear supply business in a shale gas region argued reduced use of recreational areas, caused by concerns over nearby pipelines, will adversely impact his and similar businesses.

7. Alaska Department of Natural Resources would establish risk-based safety requirements for gathering pipelines.

8. NAPSR would establish new, prescriptive requirements for large-diameter, high-pressure gathering lines.

9. Pipeline Safety Trust argued the composition of gas carried in many gathering lines leads to increased risk of corrosion and additional corrosion and testing requirements should thus be considered.

10. A private citizen, arguing for regulation of Class 1 gathering lines, noted experience has shown Class 1 locations change to Class 2 or 3 locations while the pipeline remains unchanged and, the commenter contended, unsafe.

11. Pipeline Safety Trust, Accufacts, and NAPSR would regulate gathering lines the same as transmission pipelines. PST would include integrity management requirements for lines operating at greater than 20 percent SMYS. NAPSR would impose IM if greater than 30 percent SMYS.

12. ITT Exelis Geospatial Systems contended that safety criteria applicable to a pipeline should be based on the specifications of the line.

Response to Question O.4 Comments

PHMSA appreciates the information provided by the commenters. The comments provide varied opinions for establishing new, risk-based safety requirements for gas gathering lines in rural locations. Several comments recommended PHMSA gather additional data on gathering lines before deciding to issue revised regulations. PHMSA believes rulemaking should proceed now to address the identified issues with regulation of gathering lines. Therefore, PHMSA proposes to extend existing requirements for Type B gathering lines to Type A gathering lines in Class 1 locations, if the nominal diameter is 8″ or greater. Integrity management requirements would not be applied to gathering lines at this time.

O.5. Should PHMSA consider short sections of pipeline downstream of processing, compression, and similar equipment to be a continuation of gathering? If so, what are the appropriate risk factors that should be considered in defining the scope of that limitation (*e.g.,* doesn't leave the operator's property, not longer than 1000 feet, crosses no public rights of way)?

1. The AGA, the GPTC, and a number of pipeline operators suggested that the piping mentioned in O.5 be considered as gathering. The commenters contended that this is clearly ''incidental gathering'' in API RP–80, particularly if below 20 percent SMYS, and that some agencies are presently treating this pipeline inappropriately as transmission pipeline.

2. Oleksa and Associates contended that the types of pipeline described in the question are ''incidental gathering.'' Oleksa argued that the length of these pipeline sections should not be the determining factor in their definition but, rather, risk elements and public safety impact should be afforded more importance.

3. The Gas Processors Association, the Texas Pipeline Association, and the Texas Oil & Gas Association would continue to treat these types of pipelines as gathering. They argued that this reflects the practical realities in the field regarding the ability to locate gathering-related equipment. GPA urged PHMSA to retain the concept of incidental gathering in any future change to the regulations, arguing this would continue a consistent regulatory approach to gathering pipelines.

4. The Independent Petroleum Association of America, the American Petroleum Institute, the Oklahoma Independent Petroleum Association, and Chevron contended that the safety record in the Barnett Shale area demonstrates further regulation of downstream pipelines and compression is not needed.

5. Commissioners of Wyoming County Pennsylvania would treat gathering lines as transmission lines, arguing that this would preclude the need to answer any of these questions.

6. The Delaware Solid Waste Authority (DSWA) argued for the continued treatment of the listed pipeline sections as part of gathering for landfill gas operations. DSWA noted that landfills may use intermediate compression to improve collection efficiency and may have pipe at pressure leading to flares etc.

7. Waste Management contended that piping that is an active part of a landfill gas collection and control system should be exempt from regulation as this piping is generally on landfill property and poses no risk to the public.

8. The National Solid Waste Management Association and Waste Management supported PHMSA's interpretation that pipelines operating at vacuum, such as landfill systems up to the compressor/blower should be unregulated.

Response to Question O.5 Comments

PHMSA appreciates the information provided by the commenters. See PHMSA's response to Question O.3, above.

O.6. Should PHMSA consider adopting specific requirements for pipelines associated with landfill gas

systems? If so, what regulations should be adopted and why? Should PHMSA consider adding regulations to address the risks associated with landfill gas that contains higher concentrations of hydrogen sulfide and/or carbon dioxide?

1. The AGA, the GPTC, and a number of pipeline operators contended that RP–80 makes clear that these pipelines are production piping and therefore regulation is prohibited. In addition, they argued that risk doesn't justify regulating these lines; the situation is similar to production and is already managed well. They also noted that landfill systems are generally constructed with non-corrosive materials. The commenters agreed that piping from landfills to transmission or distribution pipelines is gathering and should be regulated.

2. Oleksa and Associates contended that landfill pipelines are distribution pipelines, if they carry gas to end use customers.

3. The APGA argued that new requirements are appropriate, as landfill gas is different from natural gas. The APGA contended that application of current regulations often produces absurd results. APGA would add new requirements applicable to systems with high concentrations of hydrogen sulfide and allow systems with low concentrations to use current requirements.

4. The Delaware Solid Waste Authority argued that no new requirements are needed, because these systems operate at low pressures and existing requirements are sufficient.

5. NAPSR encouraged that PHMSA establish jurisdiction over and requirements for landfill gas systems, arguing that many operate as distribution pipelines. NAPSR also recommended that PHMSA develop requirements for odorizing landfill gas, since normal methods cannot be used.

6. The National Solid Waste Management Association and Waste Management argued that landfill gas lines under the control of a landfill operator or gas developer should remain unregulated because they pose minimal risk. They also contended that lines delivering landfill gas to distant users should also remain unregulated because they are mostly buried, are generally constructed of plastic pipe, and pose low risk due to low pressure, their dedicated nature, and lack of interconnects.

7. The National Solid Waste Management Association (NSWMA) noted that these pipelines are already regulated by the EPA and the states and argued that additional regulation would confer limited additional benefits. NSWMA argued that no requirements are needed to address internal corrosion, because these pipeline systems are generally constructed of plastic pipe and corrosive gas constituents are limited to prevent destruction of gas processing equipment. NSWMA suggested that PHMSA work with the EPA to obtain data on the landfill experience needed to support any future decision to regulate in this area.

8. Oleksa and Associates and the Delaware Solid Waste Authority would have PHMSA modify the regulations to clarify that pipe downstream of intermediate compression is unregulated, even if at pressure. They argued that the EPA has regulated such pipelines successfully and there is no safety case for applying part 192. DSWA further notes that most landfill pipeline is constructed of plastic pipe and not subject to internal corrosion.

9. Oleksa and Associates, the GPTC, Nicor, Waste Management, and the Delaware Solid Waste Authority would exempt landfill gas systems from requirements for odorization and odor sampling. They argued that there is a strong odor inherent to landfill gas, the sampling of which is not practical.

Response to Question O.6 Comments

PHMSA appreciates the information provided by the commenters. PHMSA is not proposing rulemaking to address landfill gas systems at this time, but would note that a pipeline that transports landfill gas away from the landfill facility to another destination is transporting gas. PHMSA will consider comments on this aspect of Topic O in the future.

O.7. Internal corrosion is an elevated threat to gathering systems due to the composition of the gas transported. Should PHMSA enhance its requirements for internal corrosion control for gathering pipelines? Should this include required cleaning on a periodic basis?

1. AGA, GPTC, and a number of pipeline operators commented that new requirements are not needed. They argued existing part 192 requirements are adequate for internal corrosion protection and unregulated gathering lines are rural and pose little risk.

2. AGA and a number of pipeline operators opposed a requirement for periodic cleaning of gathering lines. They noted existing lines are not configured to accommodate cleaning pigs and retrofitting them would be a major cost with no safety benefit.

3. Gas Producers Association noted internal corrosion is only one of many threats, existing regulations are adequate, and thus no new requirements are needed.

4. Texas Pipeline Association and Texas Oil & Gas Association opposed establishing internal corrosion requirements for gathering pipelines. The associations noted risk from IC is not prevalent for many gathering pipelines and suggested the need to collect data (*e.g.,* incidents) to determine whether new requirements are needed.

5. Accufacts would require, as a minimum, use of cleaning pigs and analysis of removed materials.

6. NAPSR, Alaska Department of Natural Resources, and Commissioners of Wyoming County Pennsylvania would enhance internal corrosion requirements and require periodic cleaning.

Response to Question O.7 Comments

PHMSA appreciates the information provided by the commenters. The majority of comments do not support enhancement of requirements for internal corrosion control for gathering pipelines. PHMSA is not proposing rulemaking specifically to address the need for additional internal corrosion requirements for gathering lines at this time. However, the proposed requirements in subpart I applicable to transmission lines; except the requirements in §§ 192.461(f), 192.465(f), 192.473(c) and 192.478, would be applicable to regulated Type A onshore gathering lines.

O.8. Should PHMSA apply its Gas Integrity Management Requirements to onshore gas gathering lines? If so, to what extent should those regulations be applied and why?

1. The AGA and several pipeline operators suggested that PHMSA consider applying some IM requirements to Type A gathering lines, since these lines represent conditions and risks similar to transmission pipelines. They consider IM inappropriate for Type B gathering lines, since these lines pose low risk and operate at hoop stresses similar to distribution pipelines.

2. The Gas Producers Association, the Texas Pipeline Association, the Texas Oil & Gas Association, and Atmos argued that it would be inappropriate to apply integrity management requirements to gathering pipelines. They noted that IM is a risk-based approach and that there is no evidence that gathering pipelines pose a risk that justifies application of IM.

3. The GPTC and Nicor opined that extending some aspects of gas transmission IM to non-rural, metallic

Type A gathering lines could provide enhanced protection to the public, since the operation and risk of these pipelines is similar to transmission pipelines. They cautioned, however, that the costs to impose IM on gathering pipelines would be significant. They considered IM inappropriate for Type B gathering lines since these lines are, by definition, of lower pressure and lower risk.

4. The Commissioners of Wyoming County Pennsylvania would apply IM to all onshore gathering pipelines. They would also apply requirements applicable to Class 2 transmission pipelines to Class 1 gathering pipelines, arguing that Class 1 areas will grow and class location will change.

5. Accufacts and the Alaska Department of Natural Resources would apply IM to gathering lines. Accufacts suggested an initial focus on large-diameter, high-pressure lines, since these lines are subject to failure by rupture.

Response to Question O.8 Comments

PHMSA appreciates the information provided by the commenters. PHMSA does not propose rulemaking to apply integrity management requirements to gathering lines at this time.

O.9. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- *The potential costs of modifying the existing regulatory requirements.*
- *The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.*
- *The potential impacts on small businesses of modifying the existing regulatory requirements.*
- *The potential environmental impacts of modifying the existing regulatory requirements.*

No comments were received in response to this question.

IV. Other Proposals

Inspection of Pipelines Following Extreme Weather Events.

Pipeline regulation prescribes requirements for the surveillance and periodic patrolling of the pipeline to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation, including unusual operating and maintenance conditions. The probable cause of the 2011 hazardous liquid pipeline accident resulting in a crude oil spill into the Yellowstone River near Laurel, Montana, is scouring at a river crossing due to flooding. This is a recent example of extreme weather that resulted in a pipeline incident. PHMSA has determined that additional regulations are needed to require, and establish standards for, the inspection of the pipeline and right-of-way for ''other factors affecting safety and operation'' following an extreme weather event such as a hurricane or flood, landslide, an earthquake, a natural disaster, or other similar event. The proposed rule would add a new paragraph (c) to section 192.613 to require such inspections, specify the timeframe in which such inspections should commence, and specify the appropriate remedial actions that must be taken to ensure safe pipeline operations. The new paragraph (c) would apply to onshore pipelines and their rights-of-way.

Notification for 7-Year Reassessment Interval Extension.

Section 5 of the Act identifies a technical correction amending Section 60109(c)(3)(B) of Title 49 of the United States Code to allow the Secretary of Transportation to extend the 7-year reassessment interval for an additional 6 months if the operator submits written notice to the Secretary justifying the need for the extension. PHMSA proposes to codify this statutory requirement.

Reporting Exceedances of Maximum Allowable Operating Pressure.

Section 23 of the Act requires operators to report each exceedance of the maximum allowable operating pressure (MAOP) that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. PHMSA proposes to codify this statutory requirement.

Consideration of Seismicity.

Section 29 of the Act states that in identifying and evaluating all potential threats to each pipeline segment, an operator of a pipeline facility must consider the seismicity of the area. PHMSA proposes to codify this statutory requirement to explicitly reference seismicity for data gathering and integration, threat identification, and implementation of preventive and mitigative measures.

Safety Features for In-line Inspection (ILI), Scraper, and Sphere Facilities.

PHMSA is proposing to add explicit requirements for safety features on launchers and receivers associated with ILI, scraper and sphere facilities.

Consensus Standards for Pipeline Assessments.

PHMSA is proposing to incorporate by reference consensus standards for assessing the physical condition of in-service pipelines using in-line inspection, internal corrosion direct assessment, and stress corrosion cracking direct assessment.

V. Section-by-Section Analysis

§ 191.1 Scope.

Section 191.1 prescribes requirements for the reporting of incidents, safety-related conditions, and annual pipeline summary data by operators of gas pipeline facilities. Currently, onshore gas gathering pipelines are exempt from reporting, as specified in paragraph (b)(4) of this section. In March 2012, the Government Accountability Office (GAO) issued a report (GAO–12–388) that contained a recommendation for DOT to collect data on federally unregulated hazardous liquid and gas gathering pipelines. PHMSA has determined that the statute requires the collection of additional information about gathering lines and that these reports and the congressionally required study support evaluation of the effectiveness of safety practices on these pipelines. Furthermore, PHMSA has inquired into whether any additional requirements are needed beyond those proposed in this NPRM. Accordingly, the proposed rule would repeal the exemption for reporting requirements for operators of unregulated onshore gas gathering lines by deleting § 191.1(b)(4), adding a new § 191.1(c), and making other conforming editorial amendments. In addition, Section 23 of the Act requires PHMSA to promulgate rules that require operators to report each exceedance of the maximum allowable operating pressure (MAOP) that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. The proposed rule would amend 191.1 to include MAOP exceedances within the scope of part 191.

§ 191.23 Reporting safety-related conditions.

Section 23 of the Act requires operators to report each exceedance of the maximum allowable operating pressure (MAOP) that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. On December 21, 2012, PHMSA published advisory bulletin ADB–2012–11, which advised operators of their responsibility under Section 23 of the Act to report such exceedances. PHMSA proposes to revise § 191.23 to codify this requirement.

§ 191.25 Filing safety-related condition reports.

Section 23 of the Act requires operators to report each exceedance of the maximum allowable operating pressure (MAOP) that exceeds the

margin (build-up) allowed for operation of pressure-limiting or control devices. As described above, PHMSA proposes to revise § 191.23 to codify this requirement. Section 191.25 would also be revised to provide consistent procedure, format, and structure for filing of such reports by all operators.

§ 192.3 Definitions.

Section 192.3 provides definitions for various terms used throughout part 192. In support of other regulations proposed in this NPRM, PHMSA is proposing to amend the definitions of ''*Electrical survey,*'' ''*(Onshore) gathering line,*'' and ''*Transmission line,*'' and add new definitions for ''*Close interval survey,*'' ''*Distribution center, ''* ''*Dry gas or dry natural gas,*'' ''*Gas processing plant,*'' ''*Gas treatment facility,*'' ''*Hard spot,*'' ''*In-line inspection (ILI),*'' ''*In-line inspection tool or instrumented internal inspection device*,'' ''*Legacy construction technique,*'' ''*Legacy pipe,*'' ''*Moderate consequence area,*'' ''*Modern pipe,*'' ''*Occupied site,*'' ''*Onshore production facility* or *onshore production operation,*'' ''*Significant Seam Cracking,*'' ''*Significant Stress Corrosion Cracking,*'' and ''*Wrinkle bend.*'' These changes will define these terms as used in the proposed changes to part 192. Many of the terms (such as in-line inspection, dry gas, hard spot, etc.) clarify technical definitions of terms used in part 192 or proposed in this rulemaking.

The revised definition for ''*(Onshore) gathering line,*'' and the new definitions for ''*Gas processing plant,*'' ''*Gas treatment facility,*'' and ''*Onshore production facility or onshore production operation,*'' are necessary because of ambiguous language and terminology in the current definition of regulated gas gathering lines, which invoke by reference API RP–80. The application of ''incidental gathering'' as used in API RP–80 has not been applied as intended in some cases. Several recent interpretation letters have been issued by PHMSA on this topic including an expressed intent to clarify the issue in future rulemaking. Therefore, PHMSA believes revision of the definition of gathering lines is needed and proposes repealing the use of API RP 80 as the basis for determining regulated gathering lines and would establish the new definition for ''*onshore production facility/operation, gas treatment facility, and gas processing plant,*'' and a revised definition for ''*(onshore) gathering line*'' as the basis for determining the beginning and endpoints of each gathering line.

The revised definition for ''*Electrical survey*'' aligns with the amended definition recommended in a petition dated March 26, 2012, from the Gas Piping Technology Committee (GPTC).

With regard to the new terms ''*moderate consequence area*'' or MCA, and ''*occupied site,*'' the definitions are based on the same methodology as ''*high consequence area*'' and ''*identified site*'' as defined in § 192.903. Moderate consequence areas will be used to define the subset of non-HCA locations where integrity assessments are required (§ 192.710), where material documentation verification is required (§ 192.607), and where MAOP verification is required (§§ 192.619(e) and 192.624). The criteria for determining MCA locations would use the same process and same definitions that are currently used to identify HCAs, except that the threshold for buildings intended for human occupancy and the threshold for persons that occupy other defined sites located within the potential impact radius would both be lowered from 20 to 5. This approach is proposed as a means to minimize the effort needed on the part of operators to identify the MCAs, since transmission operators must have already performed the analysis in order to have identified the HCAs or to verify that they have no HCAs. In response to NTSB recommendation P–14–01, which was issued as a result of the Sissonville, West Virginia incident, the MCA definition would also include locations where interstate highways, freeways, and expressways, and other principal 4-lane arterial roadways are located within the potential impact radius.

With regard to the new terms ''*legacy construction technique*'' and ''*legacy pipe,*'' the definitions are used in proposed and § 192.624 to identify pipe to which the proposed material verification and MAOP verification requirements would apply. The definitions are based on historical technical issues associated with past pipeline failures.

§ 192.5 Class locations.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that an important aspect of compliance with this requirement is to assure that pipeline class location records are complete and accurate. The proposed rule would add a new paragraph § 192.5(d) to require each operator of transmission pipelines to make and retain for the life of the pipeline records documenting class locations and demonstrating how an operator determined class locations in accordance with this section.

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

Section 192.7 lists documents that are incorporated by reference in part 192. PHMSA proposes conforming amendments to § 192.7 in the rule text to reflect other changes proposed in this NPRM.

§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

Section 192.8 defines the upstream and downstream endpoints of gas gathering pipelines. Recent developments in the field of gas exploration and production, such as shale gas, indicate that the existing framework for regulating gas gathering lines may no longer be appropriate. Gathering lines are being constructed to transport ''shale'' gas that range from 4 to 36 inches in diameter with MAOPs of up to 1480 psig, far exceeding the historical operating parameters of such lines.

Currently, according to the 2011 annual reports submitted by pipeline operators, PHMSA only regulates about 8,845 miles of Type A gathering lines, 5,178 miles of Type B gathering lines, and about 6,258 miles of offshore gathering lines, for a total of approximately 20,281 miles of regulated gas gathering pipelines. Gas gathering lines are currently not regulated if they are in Class 1 locations. Current estimates also indicate that there are approximately 132,500 miles of Type A gas gathering lines located in Class 1 areas (of which approximately 61,000 miles are estimated to be 8-inch diameter or greater), and approximately 106,000 miles of Type B gas gathering lines located in Class 1 areas. Also, there are approximately 2,300 miles of Type B gas gathering lines located in Class 2 areas, some of which may not be regulated in accordance with § 192.8(b)(2).

Moreover, enforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system. PHMSA has also identified a regulatory gap that permits the potential misapplication of the incidental gathering line designation under that standard. Consequently, to address these issues and gaps, the proposed rule would repeal the use of API RP 80 as the basis for determining regulated gathering lines and would establish a new definition for onshore production facility/operation and a

revised definition for gathering line as the basis for determining the beginning and endpoints of each gathering line. The definition of onshore production facility/operation includes initial preparation of gas for transportation at the production facility, including separation, lifting, stabilizing, and dehydration. Pipelines commonly referred to as ''farm taps'' serving residential/commercial customers or industrial customers are not classified as gathering, but would continue to be classified as transmission or distribution as defined in § 192.3.

§ 192.9 What requirements apply to gathering lines?

Section 192.9 identifies those portions of part 192 that apply to regulated gas gathering lines. For the same reasons discussed under § 192.8, above, the proposed rule would expand and clarify the requirements that apply to gathering lines. PHMSA proposes to extend existing regulatory requirements for Type B gathering lines to Type A gathering lines in Class 1 locations, if the nominal diameter of the line is 8″ or greater.

In addition, on August 20, 2014, the GAO released a report (GAO Report 14–667) to address the increased risk posed by new gathering pipeline construction in shale development areas. GAO recommended that a rulemaking be pursued for gathering pipeline safety that addresses the risks of larger-diameter, higher-pressure gathering pipelines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. Currently, Type A gathering lines are subject to the emergency planning requirements in § 192.615 and only include gathering lines in Class 2, 3, and 4 locations that have a Maximum Allowable Operating Pressure (MAOP) with a hoop stress of 20% or more for metallic pipe and MAOP of more than 125 psig for non-metallic pipe. Further, gathering lines that are located in Class 1 areas (*e.g.,* rural areas) are not considered Type A gathering lines even if they meet the pressure criteria specified in the preceding sentence. PHMSA is proposing to create sub-divisions of Type A gathering lines (Type A, Area 1 and Type A, Area 2). The new designation ''Type A, Area 1 gathering lines'' would apply to currently regulated Type A gathering lines. The new designation ''Type A, Area 2 gathering lines'' would apply to gathering lines with a diameter of 8-inch or greater that meet all of the qualifying parameters for currently regulated Type A gathering, but are located in Class 1 locations. PHMSA proposes to address the GAO recommendation by requiring the newly proposed Type A, Area 2 regulated onshore gathering lines, which include lines in Class 1 locations with a nominal diameter of 8-inch or greater, to develop procedures, training, notifications, and carry out emergency plans as described in § 192.615, in addition to a limited set of other specific requirements, including corrosion protection and damage prevention.

§ 192.13 General.

Section 192.13 prescribes general requirements for gas pipelines. PHMSA has determined that safety and environmental protection would be improved by generally requiring operators to evaluate and mitigate risks during all phases of the useful life of a pipeline as an integral part of managing pipeline design, construction, operation, maintenance and integrity, including management of change. This proposed rule would add a new paragraph (d) to establish a general clause requiring onshore gas transmission pipeline operators to evaluate and mitigate risks to the public and environment as part of managing pipeline design, construction, operation, maintenance, and integrity, including management of change. The new paragraph would also invoke the requirements for management of change as outlined in ASME/ANSI B31.8S, section 11, and explicitly articulate the requirements for a management of change process that are applicable to onshore gas transmission pipelines.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that an important aspect of compliance with this requirement is to assure that records that demonstrate compliance with part 192 are complete and accurate. The proposed rule would add a new paragraph (e) that clearly articulates the requirements for records preparation and retention and requires that records be reliable, traceable, verifiable, and complete. Further, the proposed Appendix A would provide specific requirements for records retention for transmission pipelines.

In addition, conforming amendments to paragraphs (a) and (b) list the effective date of the proposed requirements for newly regulated onshore gathering lines.

§ 192.67 Records: Materials.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline material records are complete and accurate. The proposed rule would add a new § 192.67 to require each operator of transmission pipelines to make and retain for the life of the pipeline the original steel pipe manufacturing records that document tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured.

§ 192.127 Records: Pipe design.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipe design records are complete and accurate. The proposed rule would add a new § 192.127 to require each operator of transmission pipelines to make and retain for the life of the pipeline records documenting pipe design to withstand anticipated external pressures and determination of design pressure for steel pipe.

§ 192.150 Passage of internal inspection devices.

The current pipeline safety regulations in 49 CFR 192.150 require that pipelines be designed and constructed to accommodate in-line inspection devices. Part 192 is silent on technical standards or guidelines for implementing requirements to assure pipelines are designed and constructed for ILI assessments. At the time these rules were promulgated, there was no consensus industry standard that addressed design and construction requirements for ILI. NACE Standard Practice, NACE SP0102–2010, ''In-line Inspection of Pipelines,'' has since been published and provides guidance in this area in Section 7. The incorporation of this standard into § 192.150 will promote a higher level of safety by establishing consistent standards for the design and construction of line pipe to accommodate ILI devices.

§ 192.205 Records: Pipeline components.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline component records are complete and

accurate. The proposed rule would add a new § 192.205 to require each operator of transmission pipelines to make and retain records documenting manufacturing and testing information for valves and other pipeline components.

§ 192.227 Qualification of welders.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline welding records are complete and accurate. The proposed rule would add a new paragraph § 192.227(c) to require each operator of transmission pipelines to make and retain for the life of the pipeline records demonstrating each individual welder qualification in accordance with this section.

§ 192.285 Plastic pipe: Qualifying persons to make joints.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. PHMSA has determined that compliance requires that pipeline qualification records are complete and accurate. The proposed rule would add a new paragraph § 192.285(e) to require each operator of transmission pipelines to make and retain for the life of the pipeline records demonstrating plastic pipe joining qualifications in accordance with this section.

§ 192.319 Installation of pipe in a ditch.

Section 192.319 prescribes requirements for installing pipe in a ditch, including requirements to protect pipe coating from damage during the process. However, during handling, lowering, and backfilling, sometimes pipe coating is damaged, which can compromise its ability to protect against external corrosion. An example of the consequences of such damage occurred in 2011 on the Bison Pipeline, operated by TransCanada Northern Border Pipeline, Inc. In this case, the probable cause of the incident was attributed to latent coating and mechanical damage caused during construction, which subsequently caused the pipeline to fail. To help prevent recurrence of such incidents, PHMSA has determined that additional requirements are needed to verify that pipeline coating systems for protection against external corrosion are not damaged during the installation and backfill process. Accordingly, this proposed rule would add a new paragraph (d) to require that onshore gas transmission operators perform an above-ground indirect assessment to identify locations of suspected damage promptly after backfill is completed and remediate any moderate or severe coating damage. Mechanical damage is also detectable by these indirect assessment methods, since the forces that are able to mechanically damage steel pipe usually result in detectable coating defects. Paragraph (d) does not apply to gas gathering lines or distribution mains. In addition, paragraph (d) would require each operator of transmission pipelines to make and retain for the life of the pipeline records documenting the coating assessment findings and repairs.

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

Section 192.452 prescribes corrosion control requirements for regulated onshore gathering lines. PHMSA proposes conforming amendments to the rule text in paragraph (b) to reflect other changes proposed in this NPRM for gas gathering lines.

§ 192.461 External corrosion control: Protective coating.

Section 192.461 prescribes requirements for protective coating systems. However, certain types of coating systems that have been used extensively in the pipeline industry can impede the process of cathodic protection if the coating disbonds from the pipe. The NTSB determined that this was a significant contributing factor in the major crude oil spill that occurred near Marshall, Michigan, in 2010. PHMSA has determined that additional requirements are needed to specify that coating should not impede cathodic protection and to ensure operators verify that pipeline coating systems for protection against external corrosion have not become compromised or damaged during the installation and backfill process. Accordingly, this proposed rule would amend paragraph (a)(4) to require that coating have sufficient strength to resist damage during installation and backfill, and add a new paragraph (f) to require that onshore gas transmission operators perform an above-ground indirect assessment to identify locations of suspected damage promptly after backfill is completed or anytime there is an indication that the coating might be compromised. It would also require prompt remediation of any moderate or severe coating damage.

§ 192.465 External corrosion control: Monitoring.

Section 192.465 currently prescribes that operators monitor cathodic protection and take prompt remedial action to correct deficiencies indicated by the monitoring. The provisions in § 192.465 do not specify the remedial actions required to correct deficiencies and do not define ''prompt.'' To address this potential issue, the proposed rule would amend paragraph (d) to require that remedial action must be completed promptly, but no later than the next monitoring interval specified in § 192.465 or within one year, whichever is less. In addition, a new paragraph (f) is added to require onshore gas transmission operators to perform close-interval surveys if annual test station readings indicate cathodic protection is below the level of protection required in subpart I. Unless it is impractical to do so, close interval surveys must be completed with the protective current interrupted. Impracticality must be based on a technical reason, for example, a pipeline protected by direct buried sacrificial anodes (anodes directly connected to the pipeline), and not on cost impact. The proposed rule would also require each operator to take remedial action to correct any deficiencies indicated by the monitoring.

§ 192.473 External corrosion control: Interference currents.

Interference currents can negate the effectiveness of cathodic protection systems. Section 192.473 prescribes general requirements to minimize the detrimental effects of interference currents. However, specific requirements to monitor and mitigate detrimental interference currents have not been prescribed in subpart I. In 2003, PHMSA issued advisory bulletin ADB–03–06 (68 FR 64189). The bulletin advised each operator of a natural gas transmission or hazardous liquid pipeline to determine whether new steel pipelines are susceptible to detrimental effects from stray electrical currents. Based on this evaluation, an operator should carefully monitor and take action to mitigate detrimental effects. The operator should give special attention to a new pipeline's physical location, particularly where that location may subject the new pipeline to stray currents from other underground facilities, including other pipelines or induced currents from electrical transmission lines, whether aboveground or underground. Operators were strongly encouraged to review their corrosion control programs and to have qualified corrosion personnel present during construction to identify, mitigate, and monitor any detrimental stray currents that might damage new

pipelines. Since the advisory bulletin, PHMSA continues to identify cases where significant pipeline defects are attributed to corrosion caused by interference currents. Examples include CenterPoint Energy's CP line (2007), Keystone Pipeline (2012) and Overland Pass Pipeline (2012). Therefore, PHMSA has determined that additional requirements are needed to explicitly require that operators conduct interference surveys and to timely remediate adverse conditions. The proposed rule would add new paragraph (c) to require that onshore gas transmission operator programs include interference surveys to detect the presence of interference currents and to require taking remedial actions promptly after completion of the survey to adequately protect the pipeline segment from detrimental interference currents, but no later than 6 months in any case.

§ 192.478 Internal corrosion control: Monitoring.

Section 192.477 prescribes requirements to monitor internal corrosion if corrosive gas is being transported. However, the existing rules do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, upset conditions, or other changes. This could result in pipelines that are not monitored for internal corrosion, because an initial assessment did not identify the presence of corrosive gas. In September 2000, following the Carlsbad explosion, PHMSA issued Advisory Bulletin 00–02, dated 9/1/2000 (65 FR 53803). The bulletin advised owners and operators of natural gas transmission pipelines to review their internal corrosion monitoring programs and consider factors that influence the formation of internal corrosion, including gas quality and operating parameters. Pipeline operators continue to report incidents attributed to internal corrosion. Between 2002 and November 2012, 206 incidents have been reported that were attributed to internal corrosion. PHMSA has determined that additional requirements are needed to assure that operators effectively monitor gas stream quality to identify if and when corrosive gas is being transported and to mitigate deleterious gas stream constituents (*e.g.,* contaminants or liquids). The proposed rule would add the new section 192.478 to require monitoring for deleterious gas stream constituents for onshore gas transmission operators, and require that gas monitoring data be evaluated quarterly. In addition, the proposed rule would add a requirement for onshore gas transmission operators to review the internal corrosion monitoring and mitigation program semi-annually and adjust the program as necessary to mitigate the presence of deleterious gas stream constituents. This is in addition to existing requirements to check coupons or other means to monitor for the actual presence of internal corrosion in the case of transporting a known corrosive gas stream.

§ 192.485 Remedial measures: Transmission lines.

Section 192.485 prescribes requirements for remedial measures to address general corrosion and localized corrosion pitting in transmission lines. For such conditions it specifies that the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3–805 (RSTRENG). PHMSA has determined that additional requirements are needed to assure such calculations have a sound basis. The proposed rule would revise section 192.485(c) to specify that pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.

§ 192.493 In-line inspection of pipelines.

The current pipeline safety regulations in 49 CFR 192.921 and 192.937 require that operators assess the material condition of pipelines in certain circumstances (*e.g.,* IM assessments for pipelines that could affect high consequence areas) and allow use of in-line inspection tools for these assessments. Operators of gas transmission pipelines are required to follow the requirements of ASME/ANSI B31.8S, ''Managing System Integrity of Gas Pipelines,'' in conducting their IM activities. ASME B31.8S provides limited guidance for conducting ILI assessments. Part 192 is silent on technical standards or guidelines for performing ILI assessments or implementing these requirements. At the time these rules were promulgated, there was no consensus industry standard that addressed ILI. Three related standards have since been published:

- API STD 1163–2005, ''In-Line Inspection Systems Qualification Standard.'' This Standard serves as an umbrella document to be used with and complement the NACE and ASNT standards below, which are incorporated by reference in API STD 1163.
- NACE Standard Practice, NACE SP0102–2010, ''In-line Inspection of Pipelines.''
- ANSI/ASNT ILI–PQ–2010, ''In-line Inspection Personnel Qualification and Certification.''

The API standard is more comprehensive and rigorous than requirements currently incorporated into 49 CFR part 192. The incorporation of this standard into pipeline safety regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes and software utilized by the in-line inspection industry. The API standard addresses in detail each of the following aspects of ILI inspections, most of which are not currently addressed in the regulations:

- Systems qualification process
- Personnel qualification
- In-line inspection system selection
- Qualification of performance specifications
- System operational validation
- System Results qualification
- Reporting requirements
- Quality management system

The incorporation of this standard into pipeline safety regulations will promote a higher level of safety by establishing consistent standards for conducting ILI assessments of line pipe. The NACE standard covers in detail each of the following aspects of ILI assessments, most of which are not currently addressed in part 192 or in ASME B31.8S:

- Tool selection
- Evaluation of pipeline compatibility with ILI
- Logistical guidelines, which includes survey acceptance criteria and reporting
- Scheduling
- New construction (planning for future ILI in new lines)
- Data analysis
- Data management
- The NACE standard provides a standardized questionnaire and specifies that the completed questionnaire should be provided to the ILI vendor. The questionnaire lists relevant parameters and characteristics of the pipeline section to be inspected.

PHMSA believes that the consistency, accuracy and quality of pipeline in-line inspections would be improved by incorporating the consensus NACE standard into the regulations.

The NACE standard applies to ''free swimming'' inspection tools that are carried down the pipeline by the

transported fluid. It does not apply to tethered or remotely controlled ILI tools, which can also be used in special circumstances (*e.g.,* examination of laterals). While their use is less prevalent than free swimming tools, some pipeline IM assessments have been conducted using these tools. PHMSA considers that many of the provisions in the NACE standard can be applied to tethered or remotely controlled ILI tools. Therefore, PHMSA is proposing to allow the use of these tools, provided they generally comply with the applicable sections of the NACE standard.

The ANSI/ASNT standard provides for qualification and certification requirements that are not addressed by 49 CFR part 192. The incorporation of this standard into pipeline safety regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes and software utilized by the in-line inspection industry. The ANSI/ASNT standard addresses in detail each of the following aspects, which are not currently addressed in the regulations:

- Requirements for written procedures
- Personnel qualification levels
- Education, training and experience requirements
- Training programs
- Examinations (testing of personnel)
- Personnel certification and recertification
- Personnel technical performance evaluations

The proposed rule adds a new § 192.493 to require compliance with the requirements and recommendations of the three consensus standards discussed above when conducting in-line inspection of pipelines.

§ 192.503 General requirements.

Section 192.503 prescribes the general test requirements for the operation of a new segment of pipeline, or returning to service a segment of pipeline that has been relocated or replaced. The proposed rule would add additional requirements to § 192.503(a)(1) to reflect other requirements for determination of MAOP. These include § 192.620 for alternative MAOP determination requirements and new § 192.624 for verification of MAOP for onshore, steel, gas transmission pipeline segments that: (1) Has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''); (2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; or (ii) a class 3 or class 4 location; or (3) the pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before *[effective date of rule]* and is located in one of the following areas: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

§ 192.506 Transmission lines: Spike hydrostatic pressure test for existing steel pipe with integrity threats.

The NTSB recommended repealing § 192.619(c) and requiring that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (recommendation P–11–14). Currently, part 192 does not contain any requirement for operators to conduct spike hydrostatic pressure tests. In response to the NTSB recommendation, this NPRM proposes requirements for verification of MAOP in new § 192.624, which requires that MAOP be established and documented for pipelines located in either an HCA or MCA meeting the conditions in § 192.624(a)(1) through (3) using one or more of the methods in § 192.624(c)(1) through (6). The pressure test method requires performance of a spike pressure test in accordance with new § 192.506 if the pipeline includes legacy pipe or was constructed using legacy construction techniques or if the pipeline has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking.

§ 192.517 Records.

Section 192.517 prescribes the record requirements for each test performed under §§ 192.505 and 192.507. The proposed rule would revise § 192.517 to add the record requirements for § 192.506.

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

Section 192.605 prescribes requirements for the operator's procedural manual for operations, maintenance, and emergencies. Part 192 contains numerous requirements intended to protect pipelines from overpressure events. These include mandatory pressure relieving or pressure limiting devices, inspections and tests of such devices, establishment of maximum allowable operating pressure, and administrative requirements to not operate the pipeline at pressures that exceed the MAOP, among others. Implicit in the requirements of § 192.605 is the intent for operators to establish operational and maintenance controls and procedures to effectively implement these requirements and preclude operation at pressures that exceed MAOP. PHMSA expects that operator's procedures should already address this aspect of operations and maintenance, as it is a long-standing, critical aspect of safe pipeline operations. However, § 192.605 does not explicitly prescribe this aspect of the procedural controls. In addition, as a result of the San Bruno incident, Congress mandated in Section 23 of the Act that any exceedance of MAOP on a gas transmission pipeline be reported to PHMSA. As part of such reporting, the operator should inform PHMSA of the cause(s) of each exceedance. On December 21, 2012, PHMSA published advisory bulletin ADB–2012–11, which advised transmission operators of their responsibility under Section 23 of the Act to report exceedances of MAOP that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices (*i.e.,* report any pressure exceedances over the pressure limiting or control device set point as defined in applicable sections of §§ 192.201(a)(2) or 192.739). Between December 21, 2012 and June 30, 2013, PHMSA received 14 such notifications. Therefore, PHMSA has determined that an additional requirement is needed to explicitly require procedures to maintain and operate pressure relieving devices and to control operating pressure to prevent

exceedance of MAOP. The proposed rule clarifies the existing requirements regarding such procedural controls.

§ 192.607 Verification of pipeline material: Onshore steel transmission pipelines.

Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of the pipelines and to confirm the established MAOP of the pipelines. PHMSA issued Advisory Bulletin 11–01 on January 10, 2011 (76 FR 1504) and Advisory Bulletin 12–06 on May 7, 2012 (77 FR 26822) to inform operators of this requirement. Operators have submitted information in their 2012 Annual Reports indicating that a portion of transmission pipeline segments do not have adequate records to establish MAOP or to accurately reflect the physical and operational characteristics of the pipeline. Therefore, PHMSA has determined that additional rules are needed to implement this requirement of the Act. Specifically, PHMSA has determined that additional rules are needed to require that operators conduct tests and other actions needed to understand the physical and operational characteristics for those segments where adequate records are not available, and to establish standards for performing these actions.

This issue was addressed in detail at the Integrity Verification Process workshop on August 7, 2013. Major issues that were discussed include the scope of information needed and the methodology for verifying material properties. The most difficult information to obtain, from a technical perspective, is the strength of the steel. Conventional techniques would include cutting out a piece of pipe and destructively testing it to determine yield and ultimate tensile strength. PHMSA proposes to address this in the rule by allowing new non-destructive techniques if they can be validated to produce accurate results for the grade and type of pipe being evaluated. Such techniques have already been successfully validated for some grades of pipe.

Another issue is the extremely high cost of excavating the pipeline in order to verify the material, and determining how much pipeline needs to be exposed and tested in order to have assurance of pipeline properties. PHMSA proposes to address this issue by specifying that operators take advantage of opportunities when the pipeline is exposed for other reasons, such as maintenance and repair, by requiring that material properties be verified whenever the pipe is exposed. Over time, pipeline operators will develop a substantial set of verified material data, which will provide assurance that material properties are reliably known for the entire population of inadequately documented segments. PHMSA proposes to require that operators continue this opportunistic material verification process until the operator has completed enough verifications to obtain high confidence that only a small percentage of inadequately documented pipe lengths have properties that are inconsistent with operators' past assumptions. The rule would specify the number of excavations required to achieve this level of confidence.

Lastly, PHMSA proposes criteria that would require material verification for higher risk locations. Therefore, the proposed rule would add requirements for verification of pipeline material in new § 192.607 for existing onshore, steel, gas transmission pipelines that are located in an HCA or a class 3 or class 4 location. PHMSA believes this approach appropriately addresses pipeline segment risk without extending the requirement to all pipelines where risk and potential consequences are not as significant, such as pipeline in remote rural areas.

Requirements are also included to ensure that the results of this process are documented in records that are reliable, traceable, verifiable, and complete that must be retained for the life of the pipeline.

§ 192.613 Continuing surveillance.

Section 192.613 prescribes general requirements for continuing surveillance of the pipeline to determine and take action due to changes in the pipeline from, among other things, unusual operating and maintenance conditions. The 2011 hazardous liquid pipeline accident resulting in a crude oil spill into the Yellowstone River near Laurel, Montana was probably caused by scouring at a river crossing due to flooding. Based on recent examples of extreme weather events that did result, or could have resulted, in pipeline incidents, PHMSA has determined that additional requirements are needed to assure that operator procedures adequately address inspection of the pipeline and right-of-way for ''other factors affecting safety and operation'' following an extreme weather event such as a hurricane or flood, landslide, an earthquake, a natural disaster, or other similar event. The proposed rule would add a new paragraph (c) to require such inspections, specify the timeframe in which such inspections should commence, and specify the appropriate remedial actions must be taken to ensure safe pipeline operations. The new paragraph (c) would apply to both onshore transmission pipelines and their rights-of-way.

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

The NTSB issued its report on the San Bruno incident that included a recommendation (P–11–15) that PHMSA amend its regulations so that manufacturing and construction-related defects can only be considered ''stable'' if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP. This NPRM proposes to revise the test pressure factors in § 192.619(a)(2)(ii) to correspond to at least 1.25 MAOP for newly installed pipelines.

In addition, Section 23 of the Act requires verification of records to confirm the established MAOP of the pipelines. Operators have submitted information in their 2012 Annual Reports indicating that a portion of gas transmission pipeline segments do not have adequate records to establish MAOP. For pipelines without an adequately documented basis for MAOP, the proposed rule adds a new paragraph (e) to § 192.619 to require that certain onshore steel transmission pipelines that meet the criteria specified in § 192.624(a), and that do not have adequate records to establish MAOP, must establish and document MAOP in accordance with new § 192.624 using one or more of the methods in § 192.624(c)(1) through (6), as discussed in more detail below.

The proposed rule would also add a new paragraph (f) to explicitly require that records documenting tests, design, and other information necessary to establish MAOP be retained for the life of the pipeline.

Lastly, the rule would incorporate conforming changes to § 192.619(a) to reflect changes to gas gathering regulations proposed in §§ 192.8 and 192.9.

§ 192.624 Maximum allowable operating pressure verification: Onshore steel transmission pipelines.

Section 23 of the Act requires verification of records used to establish MAOP for pipe in class 3 and class 4 locations and high-consequence areas in Class 1 and 2 locations to ensure they accurately reflect the physical and operational characteristics of the pipelines and to confirm the established MAOP of the pipelines. Operators have submitted information in their 2012 Annual Reports indicating that some gas transmission pipeline segments do not

have adequate records or testing to establish MAOP. For pipelines so identified, the Act requires that PHMSA promulgate regulations to require operators to test the segments to confirm the material strength of the pipe in HCAs that operate at stress levels greater than or equal to 30% SMYS. Such tests must be performed by pressure testing or other methods determined by the Secretary to be of equal or greater effectiveness.

As a result of its investigation of the San Bruno accident, NTSB issued two related recommendations. NTSB recommended that PHMSA repeal § 192.619(c) and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test (P–11–14). NTSB also recommended that PHMSA amend the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure (P–11–15).

The proposed rule would add a new § 192.624 to address these mandates and recommendations. The rule would require that operators re-establish and document MAOP for certain onshore steel transmission pipelines located in an HCA or MCA that meet one or more of the criteria specified in § 192.624(a). Those criteria include: (1) Has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs''); (2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline segment is located in one of the following locations: (i) A high consequence area as defined in § 192.903; or (ii) a class 3 or class 4 location; or (3) the pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) of this subpart before *[effective date of rule]* and is located in one of the following areas: (i) A high consequence area as defined in § 192.903; (ii) a class 3 or class 4 location; or (iii) a moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

The methods specified in § 192.624 include the pressure test method. If the pipeline includes legacy pipe or was constructed using legacy construction techniques or the pipeline has experienced a reportable in-service incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, a spike pressure test in accordance with new § 192.506 would be required. For modern pipe without the aforementioned risk factors, a pressure test in accordance with § 192.505 would be allowed.

Other methods to reestablish MAOP for pipe currently operating under § 192.619(c) would also be allowed. PHMSA has determined that the following methods would provide equal or greater effectiveness as a pressure test:

(i) De-rating the pipe segment such that the new MAOP is less than historical actual sustained operating pressure by using a safety factor of 0.80 times the sustained operating pressure (equivalent to a pressure test using gas or water as the test medium with a test pressure of 1.25 times MAOP). For segments that operate at stress levels of less than 30% SMYS a safety factor of 0.90 times sustained operating pressure is allowed (equivalent to a pressure test of 1.11 times MAOP), supplemented with additional integrity assessments, and preventive and mitigative measures specified in the proposed rule.

(ii) Replacement of the pipe, which would require a new pressure test that conforms with subpart J before being placed in service,

(iii) An in-line inspection and Engineering Critical Assessment process using technical criteria to establish a safety margin equivalent to that provided by a pressure test, or

(iv) Use of other technology that the operator demonstrates provides an equivalent or greater level of safety, provided PHMSA is notified in advance.

The proposed rule establishes requirements for pipelines operating at stress levels of less than 30% of SMYS based on technical information provided in Interstate Natural Gas Association of America/American Gas Association Final Report No. 13–180, ''Leak vs. Rupture Thresholds for Material and Construction Anomalies,'' December 2013. The report references a 2010 study by Kiefner & Associates, Inc. ''Numerical Modeling and Validation for Determination of the Leak/Rupture Boundary for Low-Stress Pipelines'' performed under contract to the Gas Technology Institute (GTI). The Kiefner/GTI report evaluated theoretical fracture models and supporting test data in order to define a possible leak-rupture threshold stress level. The report pointed out that ''no evidence was found that a propagating ductile rupture could arise from an incident attributable to any one of these causes in a pipeline that is being operated at a hoop stress level of 30% of SMYS or less.'' In addition, the INGAA/AGA report included a review of Kiefner & Associates, Inc. failure investigation reports, which concluded that all manufacturing related defects failing under the action of hoop stress alone failed as leaks if the hoop stress level was 30% SMYS or less except for one case out of 94 which failed at 27% of SMYS. The INGAA/AGA report states that a hydrostatic test to 1.25 times the MAOP is unnecessary to reasonably assure stability of pipe manufacturing construction related features in pipe meeting the following conditions: (1) Ductile fracture initiation is assured by showing that the pipe has an operating temperature above the brittle fracture initiation temperature; (2) interaction with in-service degradation mechanics such as selective seam weld corrosion or previous mechanical damage is absent; (3) hoop stress is 30% or less; (4) mill pressure testing was conducted at 60% SMYS or more, established by documented conformance to applicable pipe product specifications (*e.g.,* API 5L) or company specifications; and (5) pipe is 6 NPS or smaller. For pipes that are 8 NPS or larger but still meeting the conditions mentioned above, hydrostatic pressure testing to 1.25 times the MAOP is still prudent, since theoretical analysis as well as full scale laboratory tests show that failure as a rupture is possible for stress thresholds below 30% of SMYS. However, NPS 8 pipe may be prioritized lower than larger pipe because there were no reported incidents of service rupture in pipe that size where all other criteria were met. PHMSA plans to limit stress levels, pressures, and pipe diameters that can meet the potential impact

radius and require alternative integrity and preventative and mitigative measures for pipelines that use these criteria to establish MAOP.

The above approach implements the regulatory mandate in the Act for segments in HCAs. In addition, the scope includes additional pipe segments in the newly defined moderate consequence areas. This approach is intended to address the NTSB recommendations and to provide increased safety in areas where a pipeline rupture would have a significant impact on the public or the environment. PHMSA does not propose to repeal 49 CFR 192.619(c) for segments located outside of HCAs or MCAs where the routine presence of persons is not expected.

The Engineering Critical Assessment process requires the conservative analysis of: Any in-service cracks, crack-like defects remaining in the pipe, or the largest possible crack that could remain in the pipe, including crack dimensions (length and depth) to determine the predicted failure pressure (PFP) of each defect; failure mode (ductile, brittle, or both) for the microstructure, location, type of defect, and operating conditions (which includes pressure cycling); and failure stress and crack growth analysis to determine the remaining life of the pipeline. An Engineering Critical Assessment must use techniques and procedures developed and confirmed through research findings provided by PHMSA, and other reputable technical sources for longitudinal seam and crack growth such as PHMSA's Comprehensive Study to Understand Longitudinal ERW Seam Research & Development study task reports: Battelle Final Reports (''Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications''—Task 1.4), Report No. 13–002 (''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams''—Subtask 2.4), Report No. 13–021 (''Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue''—Subtask 2.5), and ''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1''—Task 4.5), which can be found on the internet at: *https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390*.

Section 23 requires pipeline operators to conduct a records verification for pipelines located in certain areas to ensure that the records accurately reflect the physical and operational characteristics of the pipelines and confirm the established MAOP. Congress further directed DOT to require the owner or operator to reconfirm a maximum allowable operating pressure for pipelines with insufficient records. This rule proposes methods for satisfying this direction from Congress. In analyzing the impact of the proposed methods, PHMSA determined that they would result in large cost savings ($2.67 billion over 15 years discounted at 7%, $3.67 billion discounted at 3%) relative to current regulatory requirements for pipelines with insufficient records in 49 CFR 192.107(b), The results of that action indicated that problems similar to those that contributed to the San Bruno incidents are more widespread than previously believed. As a result, the proposed rule would establish consistent standards by which operators would correct these issues in a way that is more cost effective than the current regulations would require (which could require more extensive destructive testing, pressure testing, and/or pipe replacement). PHMSA did not identify any significant adverse safety impacts from allowing operators to use the proposed methods instead of those in the current regulations. See section 4.1.2.3 in the regulatory impact analysis for the analysis of the cost savings.

PHMSA estimated the cost savings to operators associated with the Section 23(c) mileage. Existing regulatory requirements [§ 192.107(b)] related to bad or missing records would be more costly for operators to achieve compliance. Under existing regulations, in order for pipelines with insufficient records to maintain operating pressure, operators must excavate the pipeline at every 10 lengths of pipe (commonly referred to as joints) in accordance with section II–D of appendix B of part 192 (as specified in § 192.107(b)), do a cutout, determine material properties by destructive tensile test, and repair the pipe. The process is similar to doing a repair via pipe replacement. PHMSA developed a blended average for performing such a cutout material verification ($75,000) by reviewing typical costs to repair a small segment of pipe by pipe replacement. The blended average accounted for various pipe diameters and regional cost variance. PHMSA assumed each joint is 40 feet long; ten joints is 400 ft. The number of cutouts required by existing rules is therefore the miles subject to this requirement multiplied by 5,280/400.

The proposed rule would allow operators to perform a sampling program that opportunistically takes advantage of repairs and replacement projects to verify material properties at the same time. Over time, operators will collect enough information gain significant confidence in the material properties of pipe subject to this requirement. The proposed rule nominally targets conducting an average of one material documentation process per mile. In addition, operators would be allowed to perform nondestructive examinations, in lieu of cutouts and destructive testing, when the technology provides a demonstrable level of confidence in the result. PHMSA estimated that the incremental unit cost of adding material documentation activities to a repair or replacement activity would be approximately $17,000 per instance.

The proposed methods for addressing pipelines with insufficient records are exclusively applicable to HCA and all Class 3 and 4 locations. Therefore, if the proposed rule were in effect, operators would be able to use the new methods for addressing pipeline with insufficient records in HCA and all Class 3 and 4 locations, but they would be required to comply with existing (more expensive) requirements for addressing the same issue for pipelines located outside HCA and all Class 3 and 4 locations. Locations outside HCAs and all Class 3 and 4 are by definition lower risk, meaning if incidents occur, the consequences are expected to be smaller than HCA and all Class 3 and 4 locations. PHMSA is considering including provisions in the final rule that would enable operators to use the proposed methods for addressing pipelines with insufficient records in locations outside HCAs and all Class 3 and 4. To maintain flexibility, the proposed methods may be an option to existing requirements—as opposed to a replacement of those requirements. PHMSA requests comments on the impacts of allowing operators to use the new methods for addressing insufficient records beyond HCAs and all Class 3 and 4 locations. What safety risks, if any, should PHMSA consider? What are the potential cost savings?

§ 192.710 Pipeline assessments.

Currently, part 192 does not contain any requirement for operators to conduct integrity assessments of onshore transmission pipelines that are not HCA segments as defined in § 192.903 and therefore not subject to subpart O; *i.e.,* pipelines that are not located in a high consequence area (HCA). Currently, only approximately 7% of onshore gas transmission pipelines are located in HCAs. However, coincident with integrity assessments of HCA segments, industry has, as a practical matter, assessed substantial amounts of pipeline in non-HCA

segments. For example, INGAA noted (see Topic A comments, above) that approximately 90 percent of Class 3 and 4 mileage not in HCAs are presently assessed through over-testing during IM assessments. This is due, in large part, because ILI or pressure testing, by their nature, assess large continuous segments that may contain some HCA segments but that could also contain significant amounts of non- HCA segments. In addition, based on the integrity management principle of continuous improvement, INGAA members have committed (via its IMCI action plan discussed under Topic A, above) to first extend some degree of integrity management to approximately 90 percent of people who live, work or otherwise congregate near pipelines (that is, within the pipelines' Potential Impact Radius, or PIR) by 2012. By 2020, INGAA operators have committed to perform full integrity management on pipelines covering 90 percent of the PIR population. At a minimum, all ASME/ANSI B31.8S requirements will be applied, including mitigating corrosion anomalies and applying integrity management principles. Continuing to areas of less population density, INGAA members plan to apply integrity management principles to pipelines covering 100 percent of the PIR population by 2030.

Given this level of commitment, PHMSA has determined that it is appropriate to codify requirements that additional gas transmission pipelines have an integrity assessment on a periodic basis to monitor for, detect, and remediate deleterious pipeline defects and injurious anomalies. However, INGAA does not represent all pipeline operators subject to part 192. In addition, in order to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, while minimizing the cost of identifying such locations, PHMSA proposes to base the requirements for identifying those locations on processes already being implemented by pipeline operators.

The proposed rule would add a new § 192.710 to require that pipeline segments in moderate consequence areas that can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'') be assessed within 15 years and every 20 years thereafter. PHMSA proposes to define a new term ''moderate consequence area'' or MCA. The definition is based on the same methodology as ''high consequence areas'' as specified in § 192.903, but with less stringent criteria. Moderate consequence areas will be used to define the subset of locations where integrity assessments are required. This approach is proposed as a means to minimize the effort needed on the part of operators to identify the MCAs, since transmission operators must have already performed the analysis in order to have identified the HCAs, or verify that they have no HCAs. In addition, the MCA definition would include locations where interstate highways, freeways, and expressways, and other principal 4-lane arterial roadways are located within the PIR.

Because significant non-HCA pipeline mileage has been previously assessed in conjunction with an assessment of HCA segments in the same pipeline, PHMSA also proposes to allow the use of those prior assessments for non-HCA segments to comply with the new § 192.710, provided that the assessment was conducted in conjunction with an integrity assessment required by subpart O.

The proposed rule would also require that the assessment required by new § 192.710 be conducted using the same methods as proposed for HCAs (see § 192.921, below).

§ 192.711 Transmission lines: General requirements for repair procedures.

Section 192.711 prescribes general requirements for repair procedures. For non-HCA segments, the existing rule requires that permanent repairs be made as soon as feasible. However, no specific repair criteria are provided and no specific timeframe or pressure reduction requirements are provided. PHMSA has determined that more specific repair criteria are needed for pipelines not covered under the integrity management rule. The proposed rule would amend paragraph (b)(1) of section 192.711 to require that specific conditions (*i.e.,* repair criteria) defined in proposed § 192.713 (see below) be remediated, and to require a reduction of operating pressure for conditions that present an immediate hazard.

§ 192.713 Transmission lines: Permanent field repair of imperfections and damages.

Section 192.713 prescribes requirements for the permanent repair of pipeline imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS. PHMSA has determined that more explicit requirements are needed to better identify criteria for the severity of imperfection or damage that must be repaired, and to identify the timeframe within which repairs must be made. Further, PHMSA has determined that such repair criteria should apply to any transmission pipeline not covered under subpart O, Integrity Management regulations. PHMSA believes that establishing these non-HCA segment repair conditions are important because, even though they are not within the defined high consequence locations, they could be located in populated areas and are not without consequence. For example, as reported by operators in the 2011 annual reports, while there are approximately 20,000 miles of gas transmission pipe in HCA segments, there are approximately 65,000 miles of pipe in Class 2, 3, and 4 populated areas. PHMSA believes it is prudent and appropriate to include criteria to assure the timely repair of injurious pipeline defects in non-HCA segments. These changes will ensure the prompt remediation of anomalous conditions, while allowing operators to allocate their resources to high consequence areas on a higher priority basis. The proposed rule would amend § 192.713 to establish immediate, two-year, and monitored conditions which the operator must remediate or monitor to assure pipeline safety. PHMSA proposes to use the same criteria as proposed for HCAs (see 192.933, below), except that conditions for which a one-year response is required in HCAs would require a two-year response in non-HCA segments. In addition, PHMSA proposes to prescribe more explicit requirements for *in situ* evaluation of cracks and crack-like defects using in-the-ditch tools whenever required, such as when an ILI, SCCDA, pressure test failure, or other assessment identifies anomalies that suggest the presence of such defects.

§ 192.750 Launcher and receiver safety.

PHMSA has determined that more explicit requirements are needed for safety when performing maintenance activities that utilize launchers and receivers to insert and remove maintenance tools and devices. Such facilities are subjected to pipeline system pressures. Current regulations for hazardous liquid pipelines (part 195) have, since 1981, contained such safety requirements for scraper and sphere facilities (re: § 195.426). However, current regulations for gas pipelines (part 192) do not similarly require controls or instrumentation to protect against inadvertent breach of system integrity due to incorrect operation of launchers and receivers for in-line inspection tools, scraper, and sphere facilities. Accordingly, the proposed rule would add a new section § 192.750 to require a suitable means to relieve pressure in the barrel and either a means to indicate the pressure in the

barrel or a means to prevent opening if pressure has not been relieved.

§ 192.911 What are the elements of an integrity management program?

Paragraph (k) of § 192.911 requires that integrity management programs include a management of change process as outlined in ASME/ANSI B31.8S, section 11. PHMSA has determined that specific attributes and features of the management of change process as currently specified in ASME/ANSI B31.8S, section 11, should be codified directly within the text of § 192.911(k). The proposed rule would amend paragraph (k) to specify that the features of the operator's management of change process must include the reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. These general attributes of change management are already required by virtue of being invoked by reference to ASME/ANSI B31.8S. However, PHMSA believes it will improve the visibility and emphasis on these important program elements to require them directly in the rule text.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

Section 192.917 requires that integrity management programs for covered pipeline segments identify potential threats to pipeline integrity and use the threat identification in its integrity program. Included within this performance-based process are requirements to identify threats to which the pipeline is susceptible, collect data for analysis, and perform a risk assessment. Special requirements are included to address plastic pipe and particular threats such as third party damage and manufacturing and construction defects. Following the San Bruno accident, the NTSB recommended that Pacific Gas and Electric (PG&E) assess every aspect of its integrity management program, paying particular attention to the areas identified in the investigation, and implement a revised program that includes, at a minimum,

(1) a revised risk model to reflect the Pacific Gas and Electric Company's actual recent experience data on leaks, failures, and incidents;

(2) consideration of all defect and leak data for the life of each pipeline, including its construction, in risk analysis for similar or related segments to ensure that all applicable threats are adequately addressed;

(3) a revised risk analysis methodology to ensure that assessment methods are selected for each pipeline segment that address all applicable integrity threats, with particular emphasis on design/material and construction threats; and

(4) an improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered pipeline segment (NTSB recommendation P–11–29).

In addition, the NTSB recommended that PG&E conduct threat assessments using the revised risk analysis methodology incorporated in its integrity management program, as recommended in Safety Recommendation P–11–29, and report the results of those assessments to the California Public Utilities Commission and the Pipeline and Hazardous Materials Safety Administration (NTSB recommendation P–11–30). PHMSA has also analyzed the issues the NTSB identified in the investigation related to information analysis and risk assessment. PHMSA held a workshop on July 21, 2011 to address perceived shortcomings in the implementation of integrity management risk assessment processes and the information and data analysis (including records) upon which such risk assessments are based. PHMSA sought input from stakeholders on these issues and has determined that additional clarification and specificity is needed for existing performance-based rules. These clarifications define and emphasize the specific functions that are required for risk assessment and effective risk management.

These aspects of integrity management have been an integral part of PHMSA's expectations for integrity management since the inception of the program. As specified in § 192.907(a), PHMSA expected operators to start with a framework, which would evolve into a more detailed and comprehensive program, and that the operator must continually improve its integrity management program, as it learned more about the process and about the material condition of its pipelines through integrity assessments.

PHMSA elaborated on this philosophy in the notice of final rulemaking for subpart O (68 FR 69778):

The intent of allowing a framework was to acknowledge that an operator cannot develop a complete, fully mature integrity management plan in a year. Nevertheless, it is important that an operator have thought through how the various elements of its plan relate to each other early in the development of its plan. The framework serves this purpose. . . . It need not be fully developed or at the level of detail expected of final integrity management plans. The framework is an initial document that evolves into a more detailed and comprehensive program.

The clarifications and additional specificity proposed in this NPRM (with respect to processes for implementing the threat identification, risk assessment, and preventive and mitigative measures program elements), reflect PHMSA's expectation regarding the degree of progress operators should be making, or should have made, during the first 10 years of the integrity management program.

The current integrity management rule invokes ASME/ANSI B31.8S by reference to require that operators implement specific attributes and features of the threat identification, data analysis, and risk assessment process. PHMSA has determined that those specific attributes and features of the threat identification, data analysis, and risk assessment processes as currently specified in ASME/ANSI B31.8S, section 11, should be codified within the text of § 192.917. While continuing to incorporate the industry standard by reference, the proposed rule would amend § 192.917 to insert certain critical features of the industry standard (ASME/ANSI B31.8S) directly into the body of the Federal regulation. Specifically, PHMSA proposes to specify several pipeline attributes that must be included in pipeline risk assessments and to explicitly require that operators integrate analyzed information, and ensure that data be verified and validated to the maximum extent practical. PHMSA also acknowledges that objective, documented data is not always available or obtainable. To the degree that subjective data from subject matter experts must be used, PHMSA proposes to require that an operator's program include specific features to compensate for subject matter expert bias.

In addition, PHMSA proposes to clarify the performance-based risk assessment aspects of the IM rule to specify that operators perform risk assessments that are adequate to evaluate the effects of interacting threats; determine additional preventive and mitigative measures needed, analyze how a potential failure could affect high consequence areas, including the consequences of the entire worst-case incident scenario from initial failure to incident termination; identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location, account for, and compensate for, uncertainties in the

model and the data used in the risk assessment; and evaluate risk reduction associated with candidate risk reduction activities such as preventive and mitigative measures. In addition, in response to specific NTSB recommendation P–11–18, PHMSA proposes performance-based language to require that operators validate their risk models in light of incident, leak, and failure history and other historical information. Such features are currently requirements by virtue of being invoked by reference in ASME/ANSI B31.8S. However, PHMSA believes that these important aspects of integrity management will receive greater emphasis and awareness if incorporated directly into the rule text. The proposed rule would also amend the requirements for plastic pipe to provide specific examples of integrity threats for plastic pipe that must be addressed.

Lastly, PHMSA proposes to revise the criteria in § 192.917(e)(3) and (4) for addressing the threat of manufacturing and construction defects and concluding that latent defects are stable as recommended in NTSB recommendation P–11–15.

§ 192.921 How is the baseline assessment to be conducted?

Section 192.921 requires that pipelines subject to integrity management rules have an integrity assessment. Current rules allow the use of in-line inspection, pressure testing in accordance with subpart J, direct assessment for the threats of external corrosion, internal corrosion, and stress corrosion cracking, and other technology that the operator demonstrates provides an equivalent level of understanding of the condition of the pipeline. Following the San Bruno accident, PHMSA has determined that baseline assessment methods should be clarified to emphasize in-line inspection and pressure testing over direct assessment. At San Bruno, PG&E relied heavily on direct assessment under circumstances for which direct assessment was not effective. Further, ongoing research and industry response to the ANPRM is beginning to indicate that stress corrosion cracking direct assessment is not as effective, and does not provide an equivalent understanding of pipe conditions with respect to SCC defects, as ILI or hydrostatic pressure testing at test pressures that exceed those test pressures required by subpart J (*i.e.,* ''spike'' hydrostatic pressure test). Therefore, the proposed rule would require that direct assessment only be allowed when the pipeline cannot be assessed using in-line inspection tools. The proposed rule would also add three additional assessment methods: (1) A ''spike'' hydrostatic pressure test, which is particularly well suited to address SCC and other cracking or crack-like defects, (2) guided wave ultrasonic testing (GWUT) which is particularly appropriate in cases where short segments, such as road or railroad crossing, are difficult to assess, and (3) excavation with direct *in situ* examination.

The current rule merely indicates that in-line inspection (ILI) is an accepted assessment method. The regulations are currently silent on a number of issues that significantly impact the quality and effectiveness of ILI assessment results. Such considerations are described in ASME/ANSI B31.8S, but limited guidance is provided. As discussed above, the proposed rule strengthens guidance in this area by adding a new § 192.493 to require compliance with the requirements and recommendations of API STD 1163–2005, NACE SP0102–2010, and ANSI/ASNT ILI–PQ–2010 when conducting in-line inspection of pipelines. Section 192.921(a)(1) would be revised to require compliance with § 192.493 instead of ASME B31.8S for baseline ILI assessments for covered segments. In addition, a person qualified by knowledge, training, and experience would be required to analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline, and must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

GWUT has been in use by pipeline operators for several years. Previously, operators were required by § 192.921(a)(4) to submit a notification to PHMSA as an ''other technology'' assessment method, in order to use GWUT. In 2007, PHMSA developed guidelines for how it would evaluate notifications for use of GWUT. These guidelines have been effectively used for seven years, and PHMSA has gained confidence that GWUT can be effectively used to assess the integrity of short segments of pipe. PHMSA proposes to incorporate these guidelines into a new Appendix F, which would be invoked in § 192.921. Therefore, notification for use of GWUT would no longer be required.

ASME B31.8S, Section 6.1, describes both excavation and direct *in situ* examination as specialized integrity assessment methods, applicable to particular circumstances:

It is important to note that some of the integrity assessment methods discussed in para. 6 only provide indications of defects. Examination using visual inspection and a variety of nondestructive examination (NDE) techniques are required, followed by evaluation of these inspection results in order to characterize the defect. The operator may choose to go directly to examination and evaluation for the entire length of the pipeline segment being assessed, in lieu of conducting inspections. For example, the operator may wish to conduct visual examination of aboveground piping for the external corrosion threat. Since the pipe is accessible for this technique and external corrosion can be readily evaluated, performing in-line inspection is not necessary.

PHMSA proposes to clarify its requirements to explicitly add excavation and direct *in situ* examination as acceptable assessment methods.

PHMSA also proposes that mandatory integrity assessments proposed for non-HCA segments (see § 192.710, above) could also use these assessment methods.

§ 192.923 How is direct assessment used and for what threats?

As discussed in the changes to §§ 192.927 and 192.929 below, the proposed rule would incorporate by reference NACE SP0206–2006, ''Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas,'' for addressing ICDA and NACE SP0204–2008, ''Stress Corrosion Cracking Direct Assessment,'' for addressing SCCDA. Sections 192.923(b)(2) and (b)(3) would be revised to require compliance with these standards.

§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

Internal corrosion (IC) is a degradation mechanism in which steel pipe loses wall thickness due to corrosion initiating on the inside surface of the pipe. IC is one of several threats that can impact pipeline integrity. IM regulations in 49 CFR part 192 require that pipeline operators assess covered pipe segments periodically to detect degradation from threats that their analyses have indicated could affect the segment. Not all covered segments are subject to an IC threat, but some are. IC direct assessment (ICDA) is an assessment technique that can be used to address this threat for gas pipelines. ICDA involves evaluation and analysis to determine locations at which a

corrosive environment is likely to exist inside a pipeline followed by excavation and direct examination of the pipe wall to determine whether IC is occurring.

Section 192.927 specifies requirements for gas transmission pipeline operators who use ICDA for IM assessments. The requirements in § 192.927 were promulgated before the NACE standard was published. They require that operators follow ASME/ANSI B31.8S provisions related to ICDA. PHMSA has reviewed the NACE standard and finds that it is more comprehensive and rigorous than either § 192.927 or ASME B31.8S in many respects. Some of the most important features in the NACE standard are:

- The NACE standard requires more direct examinations in most cases.
- The NACE standard encompasses the entire pipeline segment and requires that all inputs and outputs be evaluated.
- The NACE standard indirect inspection model is different than the Gas Technology Institute (GTI) model currently referenced in § 192.927, but is considered to be equivalent or superior. Its range of applicability with respect to operating pressure is greater than the GTI model, thus allowing use of ICDA in pipelines with lower operating pressures and higher flow velocities.
- The NACE standard provides additional guidance on how to effectively determine areas to excavate for detailed examinations for internal corrosion.

The existing requirements in § 192.927 have one particular aspect that has proven problematic. The definition of regions and requirements for selection of direct examination locations in the regulations are tied to the covered segment. Covered segment boundaries are determined by population density and other consequence factors without regard to the orientation of the pipe and the presence of locations at which corrosive agents may be introduced or may collect and where internal corrosion would most likely be detected (*e.g.,* low spots). Section 192.927 requires that locations selected for excavation and detailed examination be within covered segments, meaning that the locations at which IC would most likely be detected may not be examined. Thus, the existing requirements do not always facilitate the discovery of internal corrosion that could affect covered segments. PHMSA is proposing to address this problem by incorporating NACE SP0206–2006 and by establishing additional requirements for addressing covered segments within the technical process defined by NACE SP0206–2006.

This proposed rule would require that operators perform two direct examinations within each covered segment the first time ICDA is performed. These examinations are in addition to those required to comply with the NACE standard practice. The additional examinations are consistent with the current requirement in § 192.927(c)(5)(ii) that operators apply more restrictive criteria when conducting ICDA for the first time and are intended to provide a verification, within the HCA, that the results of applying the NACE process for the ICDA are acceptable. Applying the NACE process requires a more precise knowledge of the pipeline's orientation (particularly slope) than operators may have in many cases. Conducting examinations within the HCA during the first application of ICDA will verify that application of the ICDA process provides adequate information about the covered segment. Operators who identify IC on these additional examinations, even though excavations at locations determined using the NACE process did not identify any, will know that improvements to their knowledge of pipeline orientation or other adjustments to their application of the NACE process to the covered segment will be needed for future uses of ICDA. § 192.927(b) and (c) are revised to address these issues.

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

Stress corrosion cracking (SCC) is a degradation mechanism in which steel pipe develops tight cracks through the combined action of corrosion and tensile stress (residual or applied). These cracks can grow or coalesce to affect the integrity of the pipeline. SCC is one of several threats that can impact pipeline integrity. IM regulations in 49 CFR part 192 require that pipeline operators assess covered pipe segments periodically to detect degradation from threats that their analyses have indicated could affect the segment, though not all covered segments are subject to an SCC threat. SCC direct assessment (SCCDA) is an assessment technique that can be used to address this threat.

Section 192.929 specifies requirements for gas transmission pipeline operators who use SCCDA for IM assessments. The requirements in § 192.929 were promulgated before NACE Standard Practice SP0204–2008 was published. They require that operators follow Appendix A3 of ASME/ANSI B31.8S. This appendix provides some guidance for conducting SCCDA, but is limited to SCC that occurs in high-pH environments. Experience has shown that pipelines also can experience SCC degradation in areas where the surrounding soil has a pH near neutral (referred to as near-neutral SCC). NACE Standard Practice SP0204–2008 addresses near-neutral SCC in addition to high-pH SCC. In addition, the NACE Standard provides technical guidelines and process requirements which are both more comprehensive and rigorous for conducting SCCDA than do § 192.929 or ASME/ANSI B31.8S.

The NACE standard provides additional guidance on:

- The factors that are important in the formation of SCC on a pipeline and what data should be collected;
- Additional factors, such as existing corrosion, which could cause SCC to form;
- Comprehensive data collection guidelines, including the relative importance of each type of data;
- Requirements to conduct close interval surveys of cathodic protection or other above-ground surveys to supplement the data collected during pre-assessment;
- Ranking factors to consider for selecting excavation locations for both near neutral and high pH SCC;
- Requirements on conducting direct examinations, including procedures for collecting environmental data, preparing the pipe surface for examination, and conducting Magnetic Particle Inspection (MPI) examinations of the pipe; and
- Post assessment analysis of results to determine SCCDA effectiveness and assure continual improvement.

NACE SP0204–2008 provides comprehensive guidelines on conducting SCCDA which are commensurate with the state of the art. It is more comprehensive in scope than Appendix A3 of ASME/ANSI B31.8S. PHMSA has concluded the quality and consistency of SCCDA conducted under IM requirements would be improved by requiring the use of NACE SP0204–2008. Revisions to § 192.929 are proposed to address these issues.

§ 192.933 What actions must be taken to address integrity issues?

Section 192.933 specifies those injurious anomalies and defects which must be remediated, and the timeframe within which remediation must occur. PHMSA has determined that the existing rule has gaps, some injurious anomalies and defects are not identified in the rule as requiring remediation in a timely manner commensurate with their seriousness. The proposed rule would designate the following types of anomalies/defects as immediate

conditions: Metal loss greater than 80% of nominal wall thickness; indication of metal-loss affecting certain longitudinal seams; significant stress corrosion cracking; and selective seam weld corrosion. The proposed rule would also designate the following types of anomalies/defects as one-year conditions: Calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations (comparable to the alternative design factor specified in § 192.620(a)); area of general corrosion with a predicted metal loss greater than 50% of nominal wall; predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld; gouge or groove greater than 12.5% of nominal wall; and any indication of crack or crack-like defect other than an immediate condition.

The methods specified in the IM rule to calculate predicted failure pressure are explicitly not valid if metal exceeds 80% of wall thickness. Corrosion affecting a longitudinal seam, especially associated with seam types that are known to be susceptible to latent manufacturing defects such as the failed pipe at San Bruno, and selective seam weld corrosion, are known time sensitive integrity threats. Stress corrosion cracking is listed in ASME/ANSI B31.8S as an immediate repair condition, which is not reflected in the current IM regulations. PHMSA proposes to add requirements to address these gaps.

With respect to SCC, PHMSA has incorporated repair criteria to address NTSB recommendation P–12–3 that resulted from the investigation of the Marshall, Michigan crude oil accident. From its investigation, the NTSB recommended that PHMSA revise § 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 (NTSB recommendation P–12–3). Although the recommendation was focused on part 195, the issue applies to gas pipelines regulated under part 192. PHMSA proposes to allow the use of engineering assessment to evaluate if SCC is significant (and thus categorized as an ''immediate'' condition), or not significant (and thus categorized as a ''one-year'' condition), but that an engineering assessment not be allowed to justify not remediating any known indications of SCC. Further, PHMSA proposes to adopt the definition of significant SCC from NACE SP0204–2008.

The current rule includes no explicit metal loss repair criteria for one-year conditions, other than one immediate condition. The rule does direct operators to use Figure 4 in ASME B31.8S to determine non-immediate metal loss repair criteria. PHMSA proposes to repeal the reference to Figure 4, and explicitly include selected metal loss repair conditions in the one-year criteria. These new criteria are consistent with similar criteria currently invoked in the hazardous liquid integrity management rule at 40 CFR 195.452(h). In addition, PHMSA proposes to incorporate safety factors commensurate with the class location in which the pipeline is located, to include predicted failure pressure less than or equal to 1.25 times MAOP for Class 1 locations, 1.39 times MAOP for Class 2 locations, 1.67 times MAOP for Class 3 locations, and 2.00 times MAOP for Class 4 locations in HCAs. Lastly, in response to the lessons learned from the Marshall, Michigan rupture, PHMSA proposes to include any crack or crack-like defect that does not meet the proposed immediate criteria, as a one year condition.

In addition, as a result of its investigation of the Marshall, Michigan crude oil spill, the NTSB recommended that PHMSA revise § 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 (NTSB recommendation P–12–4). Although the recommendation was focused on part 195, the issue applies to gas pipelines regulated under part 192. Accordingly, PHMSA proposes to amend paragraph (b) of § 192.933 to require that operators notify PHMSA whenever the operator cannot obtain sufficient information to determine if a condition presents a potential threat to the integrity of the pipeline, within 180 days of completing the assessment.

Lastly, PHMSA proposes to require that pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations would be required to be based on properties determined and documented in accordance with § 192.607.

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

Section 192.935 requires an operator to take additional measures beyond those already required by part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area (HCA). An operator must conduct a risk analysis to identify the additional measures to protect the high consequence area and improve public safety. As discussed above, PHMSA proposes to amend § 192.917 to clarify the guidance for risk analyses operators use to evaluate and select additional preventive and mitigative measures. In addition, PHMSA has determined that some additional prescriptive preventive and mitigative measures are needed to assure that public safety is enhanced in HCAs and affords greater protections for HCAs. This proposed rule would expand the listing of example preventive and mitigative measures operators must consider, require that seismicity be analyzed to mitigate the threat of outside force damage, and would add specific enhanced measures for managing external corrosion and internal corrosion inside HCAs.

With respect to additional preventive and mitigative measures operators must consider, PHMSA proposes to specify that preventive and mitigative measures include (i) correction of the root causes of past incidents in order to prevent recurrence, (ii) adequate operations and maintenance processes, (iii) adequate resources for successful execution of safety related activities, (iv) additional right-of-way patrols, (v) hydrostatic tests in areas where material has quality issues or lost records, (vi) tests to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations including material property tests from removed pipe that is

representative of the in-service pipeline, (vii) re-coating of damaged, poorly performing, or disbonded coatings, and (viii) additional depth-of-cover survey at roads, streams and rivers, among others. These example preventive and mitigative measures do not alter the fundamental requirement to identify and implement preventive and mitigative measures, but do provide additional guidance and clarify PHMSA's expectations with this important aspect of integrity management.

Section 29 of the Act requires operators to consider seismicity when evaluating threats. Accordingly, PHMSA proposes to include seismicity of the area in evaluating preventive and mitigative measures with respect to the threat of outside force damage.

With respect to internal corrosion and external corrosion, PHMSA proposes to add new paragraphs (f) and (g) to § 192.935 to specify that an operator must enhance its corrosion control program in HCAs to provide additional protections from the threat of corrosion. More specifically, operators would be required to conduct periodic close-interval surveys, coating surveys, interference surveys, and gas-quality monitoring inside HCAs. The requirements would include specific minimum performance standards for these activities.

Lastly, to conform to the revised definition of ''electrical survey,'' the use of that term in § 192.935 would be replaced with ''indirect assessment'' to accommodate other techniques in addition to close-interval surveys.

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

Section 192.937 requires that operators continue to periodically assess HCA segments and periodically evaluate the integrity of each covered pipeline segment. PHMSA has determined that conforming amendments would be needed to implement, and be consistent with, the changes discussed above for §§ 192.917, 192.921, 192.933, and 192.935. The proposed rule would require that the continual process of evaluation and assessment implement and be consistent with data integration and risk assessment information in order to identify the threats specific to each HCA segment, including interacting threats, and the risk represented by these threats (§ 192.917), selection and use of assessment methods (§ 192.921), decisions about remediation (§ 192.933), and identify additional preventive and mitigative measures (§ 192.935) to avert or reduce threats to acceptable levels.

§ 192.939 What are the required reassessment intervals?

Section 192.939 specifies reassessment intervals for pipelines subject to integrity management requirements. Section 5 of the Act includes a technical correction that clarified that periodic reassessments must occur, at a minimum of once every 7 calendar years, but that the Secretary may extend such deadline for an additional 6 months if the operator submits written notice to the Secretary with sufficient justification of the need for the extension. PHMSA would expect that any justification, at a minimum, would need to demonstrate that the extension does not pose a safety risk. By this rulemaking, PHMSA intends to codify this technical correction. The proposed rule would implement this statutory requirement.

§ 192.941 What is a low stress reassessment?

Section 192.941, among other requirements, specifies that, to address the threat of external corrosion on cathodically protected pipe in a HCA segment, an operator must perform an electrical survey (*i.e.* indirect examination tool/method) at least every 7 years on the HCA segment. PHMSA proposes to make conforming edits to the language of this requirement to accommodate the revised definition of the term ''electrical survey.'' To conform to the revised definition of ''electrical survey,'' the use of that term in § 192.941 would be replaced with ''indirect assessment'' to accommodate other techniques in addition to close-interval surveys.

Appendix A to Part 192—Records Retention Schedule for Transmission Pipelines

As discussed under § 192.13, above, the proposed rule would more clearly articulate the requirements for records preparation and retention for transmission pipelines and to require that records be reliable, traceable, verifiable, and complete. New appendix A to part 192 provides specific requirements and records retention periods.

Appendix D to Part 192—Criteria for Cathodic Protection and Determination of Measurements

Appendix D to part 192 specifies requirements for cathodic protection of steel, cast iron & ductile pipelines. PHMSA has determined that this guidance needs to be updated to incorporate lessons learned since this appendix was first promulgated in 1971. The proposed rule would update appendix D accordingly by eliminating outdated guidance on cathodic protection and interpretation of voltage measurement to better align with current standards.

Appendix E to Part 192—Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule

Appendix E to part 192 provides guidance for preventive and mitigative measures for HCA segment subject to subpart O. PHMSA proposes to make conforming edits to the language in this appendix to accommodate the revised definition of the term ''electrical survey.'' To conform to the revised definition of ''electrical survey,'' the use of that term in Appendix E would be replaced with ''indirect assessment'' to accommodate other techniques in addition to close-interval surveys.

Appendix F to Part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

As discussed under § 192.941 above, a new appendix F to part 192 is proposed to provide specific requirements and acceptance criteria for the use of GWUT as an integrity assessment method. Operators must apply all 18 criteria defined in Appendix F to use GWUT as an integrity assessment method. If an operator applied GWUT technology in a manner that does not conform to Appendix F, it would be considered ''other technology'' in §§ 192.710, 192.921, and 192. 937.

VI. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 60 standards and specifications developed and published by standard developing organizations (SDOs). In general, SDOs update and revise their published standards every 3 to 5 years to reflect modern technology and best technical practices.

The National Technology Transfer and Advancement Act of 1995 (Pub. L. 104–113) directs Federal agencies to use voluntary consensus standards in lieu of government-written standards whenever possible. Voluntary consensus standards are standards developed or adopted by voluntary bodies that develop, establish, or coordinate technical standards using agreed-upon procedures. In addition, Office of Management and Budget (OMB) issued OMB Circular A–119 to implement Section 12(d) of Public Law 104–113 relative to the utilization of consensus technical standards by

Federal agencies. This circular provides guidance for agencies participating in voluntary consensus standards bodies and describes procedures for satisfying the reporting requirements in Public Law 104–113.

In accordance with the preceding provisions, PHMSA has the responsibility for determining, via petitions or otherwise, which currently referenced standards should be updated, revised, or removed, and which standards should be added to 49 CFR parts 192, 193, and 195. Revisions to incorporated by reference materials in 49 CFR parts 192, 193, and 195 are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Public Law 112–90. Section 24 states: ''Beginning 1 year after the date of enactment of this subsection, the Secretary may not issue guidance or a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge, on an Internet Web site.'' 49 U.S.C. 60102(p).

On August 9, 2013, Public Law 113–30 revised 49 U.S.C. 60102(p) to replace ''1 year'' with ''3 years'' and remove the phrases ''guidance or'' and '', on an Internet Web site.'' This resulted in the current language in 49 U.S.C. 60102(p), which now reads as follows:

''Beginning 3 years after the date of enactment of this subsection, the Secretary may not issue a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge.''

Further, the Office of the Federal Register issued a November 7, 2014, rulemaking (79 FR 66278) that revised 1 CFR 51.5 to require that agencies detail in the preamble of a proposed rulemaking the ways the materials it proposes to incorporate by reference are reasonably available to interested parties, or how the agency worked to make those materials reasonably available to interested parties. In relation to this proposed rulemaking, PHMSA has contacted each SDO and has requested a hyperlink to a free copy of each standard that has been proposed for incorporation by reference. Access to these standards will be granted until the end of the comment period for this proposed rulemaking. Access to these documents can be found on the PHMSA Web site at the following URL: *http://www.phmsa.dot.gov/pipeline/regs* under ''Standards Incorporated by Reference.''

Consistent with the proposed amendments in this document, PHMSA proposes to incorporate by reference the following materials identified as follows:

- API Standard 1163–2005, ''In-line Inspection Systems Qualification Standards.''—This Standard serves as an umbrella document to be used with and complement companion standards. NACE RP0102 Standard Recommended Practice, In-Line Inspections of Pipelines; and ASNT ILI–PQ In-Line Inspection Personnel Qualification & Certification all have been developed enabling service providers and pipeline operators to provide rigorous processes that will consistently qualify the equipment, people, processes and software utilized in the in-line inspection industry.
- NACE Standard Practice 0102–2010, ''Inline Inspection of Pipelines.''—This standard is intended for use by individuals and teams planning, implementing, and managing ILI projects and programs. The incorporation of this standard into the Federal pipeline safety regulations would promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software utilized by the ILI industry.
- NACE Standard Practice 0204–2008, ''Stress Corrosion Cracking Direct Assessment.''—The standard practice for SCCDA presented in this standard addresses the situation in which a pipeline company has identified a portion of its pipeline as an area of interest with respect to SCC based on its history, operations, and risk assessment process and has decided that direct assessment is an appropriate approach for integrity assessment. This standard provides guidance for managing SCC by selecting potential pipeline segments, selecting dig sites within those segments, inspecting the pipe, collecting and analyzing data during the dig, establishing a mitigation program, defining the reevaluation interval, and evaluating the effectiveness of the SCCDA process.
- NACE Standard Practice 0206–2006, ''International Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas.'' This standard covers the NACE internal corrosion direct assessment (ICDA) process for normally dry natural gas pipeline systems. This standard is intended to serve as a guide for applying the NACE DG–ICDA process on natural gas pipeline systems that meet the feasibility requirements of Paragraph 3.3 of this standard.
- ANSI/ASNT ILI–PQ–2010, ''In-line Inspection Personnel Qualification and Certification.'' The ASNT standard provides for qualification and certification requirements that are not addressed in part 192. The incorporation of this standard into the Federal pipeline safety regulations would promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software utilized by the ILI industry.
- Battelle's Experience with ERW and Flash Welding Seam Failures: Causes and Implications (Task 1.4). This report presents an evaluation of the database dealing with failures originating in electric resistance welds (ERW) and flash weld (FW) seam defects as quantified by Battelle's archives and the related literature.
- Battelle Memorial Institute, ''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams'' (Subtask 2.4). This document presents an analysis of two known defect assessment methods in an effort to find suitable ways to satisfactorily predict the failure stress levels of defects in or adjacent to ERW or flash-welded line pipe seams.
- Battelle Final Report No. 13–021, ''Predicting Times to Failures for ERW Seam Defects that Grow by Pressure Cycle Induced Fatigue (Subtask 2.5).'' The work described in this report is part of a comprehensive study of ERW seam integrity and its impact on pipeline safety. The objective of this part of the work is to identify appropriate means for predicting the remaining lives of defects that remain after a seam integrity assessment and that may become enlarged by pressure-cycle-induced fatigue.
- Battelle Memorial Institute, ''Final Summary Report and recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1'' (Task 4.5).—This report summarizes work completed as part of a comprehensive project that resulted from a contract with Battelle, working with Kiefner and Associates (KAI) and Det Norske Veritas (DNV) as subcontractors, to address the concerns identified in NTSB recommendation (P–09–1) regarding the safety and performance of ERW pipe.

VII. Regulatory Analysis and Notices

This proposed 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. The amendments to the requirements for petroleum gas pipelines addressed in this rulemaking are issued under this authority.

Executive Orders 12866 and 13563, and DOT Policies and Procedures

This proposed rule is a significant regulatory action under section 3(f) of Executive Order 12866 and, therefore, was reviewed by the Office of Management and Budget. This proposed rule is significant under the Regulatory Policies and Procedures of the Department of Transportation.

(44 FR 11034, February 26, 1979).

Executive Orders 12866 and 13563 require that proposed rules deemed ''significant'' include a Regulatory Impact Analysis, and that this analysis requires quantified estimates of the benefits and costs of the rule. PHMSA is providing the PRIA for this proposed rule simultaneously with this document, and it is available in the docket.

PHMSA estimates the total present value of benefits from the proposed rule to be approximately $3,234 to $3,738 million [39] using a 7% discount rate ($4,050 to $4,663 million using a 3% discount rate) and the present value of costs to be approximately $597 million using a 7% discount rate ($711 million using a 3% discount rate). The table in the executive summary provides a detailed estimate of the average annual costs and benefits for each major topic area.

Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Flexibility Fairness Act of 1996, requires Federal regulatory agencies to prepare an Initial Regulatory Flexibility Analysis (IFRA) for any proposed rule subject to notice-and-comment rulemaking under the Administrative Procedure Act unless the agency head certifies that the making will not have a significant economic impact on a substantial number of small entities. PHMSA has data on gas transmission pipeline operators affected by the proposed rule. However, PHMSA does not have data on currently unregulated gas gathering pipeline operators. Therefore, PHMSA prepared an IFRA which is available in the docket for the rulemaking.

Executive Order 13175

PHMSA has analyzed this proposed rule according to the principles and criteria in Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Because this proposed rule would not significantly or uniquely affect the communities of the Indian tribal governments or impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

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 the information collections described below.

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

1. Title: Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 04/30/2018.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation at the Secretary's request. Based on the proposed revisions in this rule, PHMSA estimates that 100 new Type A, Area 2 gas gathering pipeline operators ~ (2200 Type A, Area 2 miles w/o prior regulation/22) will be new to these requirements. PHMSA estimates that it will take these 100 operators 6 hours to create and maintain records associated with Emergency Planning requirements. Therefore, PHMSA expects to add 100 responses and 600 hours to this information collection as a result of the provisions in the proposed rule.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 12,400.

Total Annual Burden Hours: 941,054.

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 U.S.C. 60102 requires each operator of a pipeline facility (except master meter operators) to submit to DOT a written report on any safety-related condition that causes or has caused a significant change or restriction in the operation of a pipeline facility or a condition that is a hazards to life, property or the environment. Based on the proposed revisions in this rule, PHMSA estimates that an additional 71,109 miles of pipe will become subject to the safety related condition reporting requirements. PHMSA estimates that such reports will be submitted at a rate of 0.23 reports per 1,000 miles. PHMSA expects that, collectively, Type A, Area 2 lines will submit approximately 16 reports on an annual basis. As a result, PHMSA is adding an additional 16 responses and 96 burden hours to this information collection.

Affected Public: Operators of Natural Gas, Hazardous Liquid, and Liquefied Natural Gas pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 158.

Total Annual Burden Hours: 948.

Frequency of Collection: On occasion.

3. *Title:* Pipeline Integrity Management in High Consequence Areas Gas Transmission Pipeline Operators.

OMB Control Number: 2137–0610.

Current Expiration Date: 3/31/2016.

Abstract: This information collection request pertains to Gas Transmission operators jurisdictional to 49 CFR part 192 subpart O—Gas Transmission Integrity Management Program. PHMSA is proposing that operators subject to Integrity Management requirements provide PHMSA notice when 180 days is insufficient to conduct an integrity assessment following the discovery of a condition (192.933). PHMSA estimates that 20% of the 721 operators (721*.2 =

[39] Range reflects uncertainty in defect failure rates for Topic Area 1.

144 operators) will file such a notification. PHMSA estimates that each notification will take about 30 minutes. Based on this provision, PHMSA proposes to add 144 responses and 72 hours to this information collection.

Affected Public: Gas Transmission operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 877.

Total Annual Burden Hours: 1,018,879.

Frequency of Collection: On occasion.

4. *Title:* Incident and Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 10/31/2017.

Abstract: This information collection covers the collection of information from Gas pipeline operators for Incidents and Annual reports. PHMSA is revising the Gas Transmission Incident report to incorporate Moderate Consequence Areas and to address Gathering line operators that are only subject to reporting. PHMSA estimates that operators of currently exempt gas gathering pipelines will have to submit incident reports for 27.5 incidents over the next three years, an average of 9 reports annually. However, the proposed rule is expected to reduce the number of incidents by at least 10 each year which would result in a cumulative increase of zero incidents.

PHMSA is also revising the Gas Transmission and Gas Gathering Annual Report to collect additional information including mileage of pipe subject to the IVP and MCA criteria. Based on the proposed revisions, PHMSA estimates that an additional annual 500 reports to the current 1,440 reports will be submitted based on the required reporting of non-regulated gathering lines and gathering lines now subject to certain safety provisions. Further PHMSA estimates that the Annual report will require an additional 5 hours/report to the currently approved 42 hours due to collection of MCA data and IVP provisions. Therefore the overall burden allotted for the reporting of Gas annual reports will increase by 30,700 hours from 60,480 hours (42 hours*1,440 reports) to 91,180 hours (47 hours*1,940 reports).

As a result of the provisions mentioned above, the burden for this information collection will increase by 500 responses and 30,700 burden hours.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 12,664.

Total Annual Burden Hours: 103,182

Frequency of Collection: On occasion.

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 or subject to reporting requirements under 49 CFR part 192, 193, or 195. This registry incorporates the use of two forms. The forms for assigning and maintaining Operator Identification (OPID) information are the Operator Assignment Request Form (PHMSA F 1000.1) and Operator Registry Notification Form (PHMSA F 1000.2). PHMSA plans to make revisions to the form/instructions to account for ''reporting only'' gathering operators. PHMSA estimates that 500 gas gathering operators will require a new OPID. Based on a 3 year average this results in an additional 167 responses a year initially. In addition to the OPID assignment, PHMSA estimates that 123 gathering operators will submit approx. 1 notification per year. PHMSA estimates that each submission will take approx. 1 hour to complete. Based on these provisions, PHMSA expects this information collection to increase by 290 responses and 290 burden hours.

Affected Public: Operators of Natural Gas, Hazardous Liquid, and Liquefied Natural Gas pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 920.

Total Annual Burden Hours: 920.

Frequency of Collection: On occasion.

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

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 NW., Washington, DC 20503. Comments should be submitted on or prior to June 7, 2016.

Unfunded Mandates Reform Act of 1995

An evaluation of Unfunded Mandates Reform Act (UMRA) considerations is performed as part of the Preliminary Regulatory Impact Assessment. The estimated costs to the States are approximately $1.3 million per year and are significantly less than the UMRA criterion of $151 million per year ($100 million, adjusted for inflation). The estimated costs to the private sector are in excess of the UMRA criterion of $151 million per year. A copy of the Preliminary Regulatory Impact Assessment is available for review in the docket.

National Environmental Policy Act

PHMSA analyzed this proposed 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 1500–1508), and DOT Order 5610.1C, and has preliminarily determined this action will not significantly affect the quality of the human environment. The Environmental Assessment for this proposed action is in the docket.

Executive Order 13132

PHMSA has analyzed this proposed rule according to Executive Order 13132 (''Federalism''). The proposed rule does not have a substantial direct effect 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. This proposed rule does not impose substantial direct compliance costs on State and local governments. This proposed rule would not preempt state law for intrastate pipelines. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

Executive Order 13211

This proposed rule is not a ''significant energy action'' under Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use). It is not likely to have a significant adverse effect on

supply, distribution, or energy use. Further, the Office of Information and Regulatory Affairs has not designated this proposed rule as a significant energy action.

Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (70 FR 19477) or visit *http://dms.dot.gov*.

Regulation Identifier Number (RIN)

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

List of Subjects

49 CFR Part 191

Pipeline reporting requirements, Integrity Management, Pipeline safety, Gas gathering.

49 CFR Part 192

Incorporation by reference, Pipeline Safety, Fire prevention, Security measures.

In consideration of the foregoing, PHMSA proposes to amend 49 CFR parts 191 and 192 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for part 191 is revised to read as follows:

Authority: 49 U.S.C. 5121, 60102, 60103, 60104, 60108, 60117, 60118, 60124, 60132, and 60139; and 49 CFR 1.97.

■ 2. In § 191.1, paragraphs (a) and (b)(2) and (3) are revised, paragraph (b)(4) is deleted, and paragraph (c) is added to read as follows:

§ 191.1 Scope.

(a) This part prescribes requirements for the reporting of incidents, safety-related conditions, exceedances of maximum allowable operating pressure (MAOP), annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of gas pipeline facilities located in the United States or Puerto Rico, including pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331). This part applies to offshore gathering lines and to onshore gathering lines, whether designated as ''regulated onshore gathering lines'' or not (as determined in § 192.8 of this chapter).

(b) * * *

(2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9; or

(3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.

(c) Sections 191.22(b) and 191.29 do not apply to gathering of gas—

(1) Through a pipeline that operates at less than 0 psig (0 kPa);

(2) Through an onshore pipeline that is not a regulated onshore gathering line (as determined in § 192.8 of this chapter); and

(3) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612.

■ 3. In § 191.23, revise paragraph (a)(5), add paragraph (a)(9), and revise paragraph (b)(4) to read as follows:

§ 191.23 Reporting safety-related conditions.

(a) * * **

(5) Any malfunction or operating error that causes the pressure of a distribution or gathering pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the margin (build-up) allowed for operation of pressure limiting or control devices.

* * * * *

(9) For transmission pipelines, each exceedance of the maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in §§ 192.201, 192.620(e), and 192.739, as applicable.

(b) * * *

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline and any condition under paragraph (a)(9) of this section.

■ 4. Section 191.25 is revised to read as follows:

§ 191.25 Filing safety-related condition reports.

(a) Each report of a safety-related condition under § 191.23(a)(1) through (8) must be filed (received by the Associate Administrator, OPS) within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reports may be transmitted by electronic mail to *InformationResourcesManager@dot.gov* or by facsimile at (202) 366–7128.

(b) Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in § 191.23(a)(9) for a gas transmission pipeline must be reported within five calendar days of the exceedance using the reporting methods and report requirements described in § 191.25(c).

(c) Reports may be filed by emailing information to *InformationResources Manager@dot.gov.or* by fax to (202) 366–7128. The report must be headed ''Safety-Related Condition Report'' or for § 191.23(a)(9) ''Maximum Allowable Operating Pressure Exceedances'', and provide the following information:

(1) Name, principal address, and operator identification number (OPID) of operator.

(2) Date of report.

(3) Name, job title, and business telephone number of person submitting the report.

(4) Name, job title, and business telephone number of person who determined that the condition exists.

(5) Date condition was discovered and date condition was first determined to exist.

(6) Location of condition, with reference to the State (and town, city, or county) or Offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.

(7) Description of the condition, including circumstances leading to its discovery, any significant effects of the

condition on safety, and the name of the commodity transported or stored.

(8) The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up future corrective action, including the anticipated schedule for starting and concluding such action.

■ 4a. In § 191.29, paragraph (c) is added to read as follows:

§ 191.29 National Pipeline Mapping System.

* * * * *

(c) This section does not apply to gathering lines.

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

■ 5. The authority citation for part 192 is revised to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116, 60118, 60137, and 60139; and 49 CFR 1.97.

■ 6. In § 192.3:

■ a. Add definitions for ''Close interval survey'', ''Distribution center'', and ''Dry gas or dry natural gas'' in alphabetical order;

■ b. Revise the definition of ''Electrical survey'';

■ c. Add definitions for ''Gas processing plant'' and ''Gas treatment facility,'' in alphabetical order;

■ d. Revise the definition of ''Gathering line'';

■ e. Add definitions for ''Hard spot'', ''In-line inspection (ILI)'', ''In-line inspection tool or instrumented internal inspection device'', ''Legacy construction techniques'', ''Legacy pipe'', ''Moderate consequence area'', ''Modern pipe'', ''Occupied site'', ''Onshore production facility/operation'', ''Significant seam cracking'', ''Significant stress corrosion cracking'', in alphabetical order;

■ f. Revise the definition of ''Transmission line'' and its note; and

■ g. Add a definition for ''Wrinkle bend'' in alphabetical order.

The additions and revisions to read as follows:

§ 192.3 Definitions.

* * * * *

Close interval survey means a series of closely spaced pipe-to-electrolyte potential measurements taken to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary.

* * * * *

Distribution center means a location where gas volumes are either metered or have pressure or volume reductions prior to delivery to customers through a distribution line.

* * * * *

Dry gas or dry natural gas means gas with less than 7 pounds of water per million (MM) cubic feet and not subject to excessive upsets allowing electrolytes into the gas stream.

Electrical survey means a series of closely spaced measurements of the potential difference between two reference electrodes to determine where the current is leaving the pipe on ineffectively coated or bare pipelines.

* * * * *

Gas processing plant means a natural gas processing operation, other than production processing, operated for the purpose of extracting entrained natural gas liquids and other associated non-entrained liquids from the gas stream and does not include a natural gas processing plant located on a transmission line, commonly referred to as a straddle plant.

Gas treatment facility means one or a series of gas treatment operations, operated for the purpose of removing impurities (*e.g.,* water, solids, basic sediment and water, sulfur compounds, carbon dioxide, etc.) that is not associated with a processing plant or compressor station and is not on a transmission line.

Gathering line (Onshore) means a pipeline, or a connected series of pipelines, and equipment used to collect gas from the endpoint of a production facility/operation and transport it to the furthermost point downstream of the endpoints described in paragraphs (1) through (4) of this definition:

(1) The inlet of 1st gas processing plant, unless the operator submits a request for approval to the Associate Administrator of Pipeline Safety that demonstrates, using sound engineering principles, that gathering extends to a further downstream plant other than a plant located on a transmission line and the Associate Administrator of Pipeline Safety approves such request;

(2) The outlet of gas treatment facility that is not associated with a processing plant or compressor station;

(3) Outlet of the furthermost downstream compressor used to facilitate delivery into a pipeline, other than another gathering line; or

(4) The point where separate production fields are commingled, provided the distance between the interconnection of the fields does not exceed 50 miles, unless the Associate Administrator of Pipeline Safety finds a longer separation distance is justified in a particular case (see § 190.9 of this chapter).

(5) Gathering may continue beyond the endpoints described in paragraphs (1) through (4) of this definition to the point gas is delivered into another pipeline, provided that it only does the following:

(i) It delivers gas into another gathering line;

(A) It does not leave the operator's facility surface property (owned or leased, not necessarily the fence line);

(B) It does not leave an adjacent property owned or leased by another pipeline operator's property—where custody transfer takes place; or

(C) It does not exceed a length of one mile, and it does not cross a state or federal highway or an active railroad; or

(ii) It transports gas to production or gathering facilities for use as fuel, gas lift, or gas injection gas.

(6) Pipelines that serve residential, commercial, or industrial customers that originate at a tap on gathering lines are not gathering lines; they are service lines and are commonly referred to as farm taps.

* * * * *

Hard spot means steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinnel 327 HB or Vickers 345 HV10).

* * * * *

In-line inspection (ILI) means the inspection of a pipeline from the interior of the pipe using an in-line inspection tool, which is also called *intelligent* or *smart pigging.*

In-line inspection tool or *instrumented internal inspection device* means a device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside, which is also called an *intelligent* or *smart pig.*

Legacy construction techniques mean usage of any historic, now-abandoned, construction practice to construct or repair pipe segments, including any of the following techniques:

(1) Wrinkle bends;

(2) Miter joints exceeding three degrees;

(3) Dresser couplings;

(4) Non-standard fittings or field fabricated fittings (*e.g.,* orange-peeled reducers) with unknown pressure ratings;

(5) Acetylene welds;

(6) Bell and spigots; or
(7) Puddle welds.

Legacy pipe means steel pipe manufactured using any of the following techniques, regardless of the date of manufacture:

(1) Low-Frequency Electric Resistance Welded (LF–ERW);
(2) Direct-Current Electric Resistance Welded (DC–ERW);
(3) Single Submerged Arc Welded (SSAW);
(4) Electric Flash Welded (EFW);
(5) Wrought iron;
(6) Pipe made from Bessemer steel; or
(7) Any pipe with a longitudinal joint factor, as defined in § 192.113, less than 1.0 (such as lap-welded pipe) or with a type of longitudinal joint that is unknown or cannot be determined, including pipe of unknown manufacturing specification.

* * * * *

Moderate consequence area means an onshore area that is within a potential impact circle, as defined in § 192.903, containing five (5) or more buildings intended for human occupancy, an occupied site, or a right-of-way for a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures,* and does not meet the definition of high consequence area, as defined in § 192.903. The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an occupied site, five (5) or more buildings intended for human occupancy, or a right-of-way for a designated interstate, freeway, expressway, or other principal 4-lane arterial roadway, to the outermost edge of the last contiguous potential impact circle that contains either an occupied site, five (5) or more buildings intended for human occupancy, or a right-of-way for a designated interstate, freeway, expressway, or other principal 4-lane arterial roadway.

Modern pipe means any steel pipe that it is not legacy pipe, regardless of the date of manufacture, and has a longitudinal joint factor of 1.0 as defined in § 192.113. Modern pipe refers to all pipe that is not legacy pipe.

* * * * *

Occupied site means each of the following areas:

(1) An outside area or open structure that is occupied by five (5) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

(2) A building that is occupied by five (5) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4–H facilities, or roller skating rinks.

* * * * *

Onshore production facility or *onshore production operation* means wellbores, equipment, piping, and associated appurtenances confined to the physical acts of extraction or recovery of gas from the earth and the initial preparation for transportation. Preparation for transportation does not necessarily mean the gas will meet ''pipeline quality'' specifications as may be commonly understood or contained in many contractual agreements. Piping as used in this definition may include individual well flow lines, equipment piping, and transfer lines between production operation equipment components. Production facilities terminate at the furthermost downstream point where: Measurement for the purposes of calculating minerals severance occurs; or there is commingling of the flow stream from two or more wells.

* * * * *

Significant seam cracking means cracks or crack-like flaws in the longitudinal seam or heat affected zone of a seam weld where the deepest crack is greater than or equal to 10% of wall thickness or 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 failure pressure less than or equal to 110% of SMYS, as determined in accordance with fracture mechanics failure pressure evaluation methods (§§ 192.624(c) and (d)) for the failure mode using conservative Charpy energy values of the crack-related conditions.

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.

* * * * *

Transmission line means a pipeline, other than a gathering line, that: transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; has an MAOP of 20 percent or more of SMYS; or transports gas within a storage field.

Note: A large volume customer (factories, power plants, and institutional users of gas) may receive similar volumes of gas as a distribution center.

* * * * *

Wrinkle bend. (1) Means a bend in the pipe that was formed in the field during construction such that the inside radius of the bend has one or more ripples with:

(i) An amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple; or

(ii) With ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.

(2) If the length of the wrinkle bend cannot be reliably determined, then *wrinkle bend* means a bend in the pipe where (h/D)*100 exceeds 2 when S is less than 37,000 psi (255 MPa), where (h/D)*100 exceeds $\left(\frac{47{,}000-S}{10{,}000}+1\right)$ for psi [$\left(\frac{324-S}{69}+1\right)$for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where (h/D)*100 exceeds 1 when S is 47,000 psi (324 MPa) or more.

D = The outside diameter of the pipe, in. (mm),
h = The crest-to-trough height of the ripple, in. (mm), and
S = The maximum operating hoop stress, psi (S/145, MPa).

■ 7. In § 192.5, paragraph (d) is added to read as follows:

§ 192.5 Class locations.

* * * * *

(d) Records for transmission pipelines documenting class locations and demonstrating how an operator determined class locations in accordance with this section must be retained for the life of the pipeline.

■ 8. Amend § 192.7 by removing and reserving paragraph (b)(4) and adding paragraphs (b)(10), (g)(2) through (4), (k), and (l).

The additions read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

* * * * *

(b) * * *

(10) API STD 1163–2005, ''In-Line Inspection Systems Qualification Standard,'' 1st edition, August 2001, (API STD 1163), IBR approved for § 192.493.

* * * * *

(g) * * *

(2) NACE Standard Practice 0102–2010, ''Inline Inspection of Pipelines,'' Revised 2010, (NACE SP0102), IBR approved for §§ 192.150(a) and 192.493.

(3) NACE Standard Practice 0204–2008, ''Stress Corrosion Cracking Direct Assessment,'' Revised 2008, (NACE SP0204), Reaffirmed 2008, IBR approved for §§ 192.923(b)(3) and 192.929.

(4) NACE Standard Practice 0206–2006, ''International Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas,'' (NACE SP0206–2006), IBR approved for §§ 192.923(b)(2), 192.927(b), and 192.927(c).

* * * * *

(k) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228, phone (800) 222–2768, *https://www.asnt.org/*.

(1) ANSI/ASNT ILI–PQ–2010, ''In-line Inspection Personnel Qualification and Certification,'' 2010, (ANSI/ASNT ILI–PQ–2010), IBR approved for § 192.493.

(2) [Reserved]

(l) Battelle Memorial Institute, 505 King Avenue, Columbus, OH 43201, phone (800) 201–2011, *http://www.battelle.org/*.

(1) Battelle's Experience with ERW and Flash Welding Seam Failures: Causes and Implications (Task 1.4), IBR approved for § 192.624(c) and (d).

(2) Battelle Memorial Institute, ''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams'' (Subtask 2.4), IBR approved for § 192.624(c) and (d).

(3) Battelle Final Report No. 13–021, ''Predicting Times to Failures for ERW Seam Defects that Grow by Pressure Cycle Induced Fatigue (Subtask 2.5), IBR approved for § 192.624(c) and (d).

(4) Battelle Memorial Institute, ''Final Summary Report and recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1'' (Task 4.5), IBR approved for § 192.624(c) and (d).

■ 9. Section 192.8 is revised to read as follows:

§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

(a) Each operator must determine and maintain records documenting the beginning and endpoints of each gathering line it operates using the definitions of onshore production facility (or onshore production operation), gas processing facility, gas treatment facility, and onshore gathering line as defined in § 192.3 by *[date 6 months after effective date of the final rule]* or before the pipeline is placed into operation, whichever is later.

(b) Each operator must determine and maintain records documenting the beginning and endpoints of each regulated onshore gathering line it operates as determined in § 192.8(c) by *[date 6 months after effective date of the final rule]* or before the pipeline is placed into operation, whichever is later.

(c) For purposes of part 191 of this chapter and § 192.9, ''regulated onshore gathering line'' means:

(1) Each onshore gathering line (or segment of onshore gathering line) with a feature described in the second column that lies in an area described in the third column; and

(2) As applicable, additional lengths of line described in the fourth column to provide a safety buffer:

Type	Feature	Area	Safety buffer
A	—Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is more than 125 psig (862 kPa).	*Area 1.* Class 2, 3, or 4 location (*see* § 192.5). *Area 2.* Class 1 location with a nominal diameter of 8 inches or greater.	None.
B	—Non-metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and thew MAOP is 125 psig (862 kPa) or less.	*Area 1.* Class 3, or 4 location ..... *Area 2.* An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location; (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings; or (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.	If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2(b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.

■ 10. In § 192.9, paragraphs (c), (d), and (e) are revised and paragraph (f) is added to read as follows:

§ 192.9 What requirements apply to gathering lines?

* * * * *

(c) *Type A, Area 1 lines.* An operator of a Type A, Area 1 regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.13, 192.150, 192.319, 192.461(f), 192.465(f), 192.473(c), 192.478, 192.710, 192.713, and in subpart O of this part. However, an operator of a Type A, Area 1 regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) *Type A, Area 2 and Type B lines.* An operator of a Type A, Area 2 or Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines;

(3) Carry out a damage prevention program under § 192.614;

(4) Establish a public education program under § 192.616;

(5) Establish the MAOP of the line under § 192.619;

(6) Install and maintain line markers according to the requirements for transmission lines in § 192.707;

(7) Conduct leakage surveys in accordance with § 192.706 using leak detection equipment and promptly repair hazardous leaks that are discovered in accordance with § 192.703(c); and

(8) For a Type A, Area 2 regulated onshore gathering line only, develop procedures, training, notifications, emergency plans and implement as described in § 192.615.

(e) If a regulated onshore gathering line existing on *[effective date of the final rule]* was not previously subject to this part, an operator has until *[date two years after effective date of the final rule]* to comply with the applicable requirements of this section, unless the Administrator finds a later deadline is justified in a particular case.

(f) If, after *[effective date of the final rule],* a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has one year for Type A, Area 2 and Type B lines and two years for Type A, Area 1 lines after the line becomes a regulated onshore gathering line to comply with this section.

■ 11. In § 192.13, paragraphs (a) and (b) are revised and paragraphs (d) and (e) are added to read as follows:

§ 192.13 What general requirements apply to pipelines regulated under this part?

(a) No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless:

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part according to the requirements in § 192.14.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006.	March 15 2007.
Regulated onshore gathering line to which this part did not apply until *[effective date of the final rule]*.	*[date 1 year after effective date of the final rule].*
All other pipelines	March 12, 1971.

(b) No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
Offshore gathering line	July 31, 1977.
Regulated onshore gathering line to which this part did not apply until April 14, 2006.	March 15, 2007.
Regulated onshore gathering line to which this part did not apply until *[effective date of the final rule]*.	*[date 1 year after effective date of the final rule].*
All other pipelines	November 12, 1970.

* * * * *

(d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, risks to the public and environment as an integral part of managing pipeline design, construction, operation, maintenance, and integrity, including management of change. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff.

(e) Each operator must make and retain records that demonstrate compliance with this part.

(1) Operators of transmission pipelines must keep records for the retention period specified in appendix A to part 192.

(2) Records must be reliable, traceable, verifiable, and complete.

(3) For pipeline material manufactured before *[effective date of the final rule]* and for which records are not available, each operator must re-establish pipeline material documentation in accordance with the requirements of § 192.607.

■ 12. Section 192.67 is added to subpart A to read as follows:

§ 192.67 Records: Materials.

Each operator of transmission pipelines must acquire and retain for the life of the pipeline the original steel pipe manufacturing records that document tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured, including, but not limited to, yield strength, ultimate tensile strength, and chemical composition of materials for pipe in accordance with § 192.55.

■ 13. Section 192.127 is added to subpart B to read as follows:

§ 192.127 Records: Pipe design.

Each operator of transmission pipelines must make and retain for the life of the pipeline records documenting pipe design to withstand anticipated external pressures and loads in accordance with § 192.103 and determination of design pressure for steel pipe in accordance with § 192.105.

■ 14. In § 192.150, paragraph (a) is revised to read as follows:

§ 192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new

transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices, in accordance with the requirements and recommendations in NACE SP0102–2010, section 7 (incorporated by reference, *see* § 192.7).

* * * * *

■ 15. Section 192.205 is added to subpart D to read as follows:

§ 192.205 Records: Pipeline components.

Each operator of transmission pipelines must acquire and retain records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi or greater must have records documenting the manufacturing specification in effect at the time of manufacture, including, but not limited to, yield strength, ultimate tensile strength, and chemical composition of materials.

■ 16. In § 192.227, paragraph (c) is added to read as follows:

§ 192.227 Qualification of welders and welding operators.

* * * * *

(c) Records for transmission pipelines demonstrating each individual welder qualification in accordance with this section must be retained for the life of the pipeline.

■ 17. In § 192.285, paragraph (e) is added to read as follows:

§ 192.285 Plastic pipe: Qualifying persons to make joints.

* * * * *

(e) For transmission pipelines, records demonstrating plastic pipe joining qualifications in accordance with this section must be retained for the life of the pipeline.

18. In § 192.319, paragraph (d) is added to read as follows:

§ 192.319 Installation of pipe in a ditch.

* * * * *

(d) Promptly after a ditch for a steel onshore transmission line is backfilled, but not later than three months after placing the pipeline in service, the operator must perform an assessment to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). The operator must repair any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six months of the assessment. Each operator of transmission pipelines must make and retain for the life of the pipeline records documenting the coating assessment findings and repairs.

■ 19. In § 192.452, the introductory text of paragraph (b) is revised to read as follows:

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

* * * * *

(b) *Regulated onshore gathering lines.* For any regulated onshore gathering line under § 192.9 existing on *[effective date of the final rule],* that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under § 192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

* * * * *

■ 20. In § 192.461, paragraph (a)(4) is revised and paragraph (f) is added to read as follows:

§ 192.461 External corrosion control: Protective coating.

(a) * * *

(4) Have sufficient strength to resist damage due to handling (including but not limited to transportation, installation, boring, and backfilling) and soil stress; and

* * * * *

(f) Promptly, but no later than three months after backfill of an onshore transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), conduct surveys to assess any coating damage to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). Remediate any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six months of the assessment.

■ 21. In § 192.465, the section heading and paragraph (d) are revised and paragraph (f) is added to read as follows:

§ 192.465 External corrosion control: Monitoring and remediation.

* * * * *

(d) Each operator must promptly correct any deficiencies indicated by the inspection and testing provided in paragraphs (a), (b) and (c) of this section. Remedial action must be completed promptly, but no later than the next monitoring interval in § 192.465 or within one year, whichever is less.

* * * * *

(f) For onshore transmission lines, where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in Appendix D of this part, the operator must determine the extent of the area with inadequate cathodic protection. Close interval surveys must be conducted in both directions from the test station with a low cathodic protection (CP) reading at a minimum of approximately five foot intervals. Close interval surveys must be conducted, where practical based upon geographical, technical, or safety reasons. Close interval surveys required by this part must be completed with the protective current interrupted unless it is impractical to do so for technical or safety reasons. Remediation of areas with insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline must be performed in accordance with paragraph (d) of this section. The operator must confirm restoration of adequate cathodic protection by close interval survey over the entire area.

■ 22. In § 192.473, paragraph (c) is added to read as follows:

§ 192.473 External corrosion control: Interference currents.

* * * * *

(c) For onshore gas transmission pipelines, the program required by paragraph (a) of this section must include:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be taken on a periodic basis including, when there are current flow increases over pipeline segment grounding design, from any co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could impact the effectiveness of cathodic protection; and

(3) Implementation of remedial actions to protect the pipeline segment from detrimental interference currents

promptly but no later than six months after completion of the survey.

■ 23. Section 192.478 is added to read as follows:

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

(a) For onshore transmission pipelines, each operator must develop and implement a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects. Potentially corrosive constituents include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water, either by itself or in combination. Each operator must evaluate the partial pressure of each corrosive constituent by itself or in combination to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.

(b) The monitoring and mitigation program in paragraph (a) of this section must include:

(1) At points where gas with potentially corrosive contaminants enters the pipeline, the use of gas-quality monitoring equipment to determine the gas stream constituents;

(2) Product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents;

(3) Evaluation twice each calendar year, at intervals not to exceed 7½ months, of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

(c) If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked at least twice each calendar year, at intervals not exceeding 7½ months.

(d) Each operator must review its monitoring and mitigation program at least twice each calendar year, at intervals not to exceed 7½ months, based on the results of its gas stream sampling and internal corrosion monitoring in (a) and (b) and implement adjustments in its monitoring for and mitigation of the potential for internal corrosion due to the presence of potentially corrosive gas stream constituents.

■ 24. In § 192.485, paragraph (c) is revised to read as follows:

§ 192.485 Remedial measures: Transmission lines.

* * * * *

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, *see* § 192.7) or the procedure in PRCI PR 3–805 (R–STRENG) (incorporated by reference, *see* § 192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the procedures, including the appropriate use of class location and pipe longitudinal seam factors in pressure calculations for pipe defects. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria must be used and justification of the criteria must be documented. Pipe and material properties used in remaining strength calculations and the pressure calculations made under this paragraph must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.

■ 25. Section 192.493 is added to subpart I to read as follows:

§ 192.493 In-line inspection of pipelines.

When conducting in-line inspection of pipelines required by this part, each operator must comply with the requirements and recommendations of API STD 1163, *In-line Inspection Systems Qualification Standard;* ANSI/ASNT ILI–PQ–2010, *In-line Inspection Personnel Qualification and Certification;* and NACE SP0102–2010, *In-line Inspection of Pipelines* (incorporated by reference, see § 192.7). Assessments may also be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102–2010, provided they comply with those sections of NACE SP0102–2010 that are applicable.

■ 26. In § 192.503, paragraph (a)(1) is revised to read as follows:

§ 192.503 General requirements.

(a) * * *

(1) It has been tested in accordance with this subpart and § 192.619, 192.620, or 192.624 to substantiate the maximum allowable operating pressure; and

* * * * *

■ 27. Section 192.506 is added to read as follows:

§ 192.506 Transmission lines: Spike hydrostatic pressure test for existing steel pipe with integrity threats.

(a) Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and has been found to have integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment must be strength tested by a spike hydrostatic pressure test in accordance with this section to substantiate the proposed maximum allowable operating pressure.

(b) The spike hydrostatic pressure test must use water as the test medium.

(c) The baseline test pressure without the additional spike test pressure is the test pressure specified in § 192.619(a)(2), 192.620(a)(2), or 192.624, whichever applies.

(d) The test must be conducted by maintaining the pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505(e).

(e) After the test pressure stabilizes at the baseline pressure and within the first two hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.50 times MAOP or 105% SMYS. This spike hydrostatic pressure test must be held for at least 30 minutes.

(f) If the integrity threat being addressed by the spike test is of a time-dependent nature such as a cracking threat, the operator must establish an appropriate retest interval and conduct periodic retests at that interval using the same spike test pressure. The appropriate retest interval and periodic tests for the time-dependent threat must be determined in accordance with the methodology in § 192.624(d).

(g) *Alternative technology or alternative technical evaluation process.* Operators may use alternative technology or an alternative technical evaluation process that provides a sound engineering basis for establishing a spike hydrostatic pressure test or equivalent. If an operator elects to use alternative technology or an alternative technical evaluation process, the operator must notify PHMSA at least 180 days in advance of use in accordance with § 192.624(e). The operator must submit the alternative technical evaluation to the Associate Administrator of Pipeline Safety with the notification and must obtain a ''no objection letter'' from the Associate Administrator of Pipeline Safety prior to usage of alternative technology or an alternative technical evaluation process.

The notification must include the following details:

(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;

(2) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;

(3) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;

(4) Assessment techniques and acceptance criteria;

(5) Remediation methods for assessment findings;

(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;

(7) Procedures for remaining crack growth analysis and pipe segment life analysis for the time interval for additional assessments, as required; and

(8) Evidence of a review of all procedures and assessments by a subject matter expert(s) in both metallurgy and fracture mechanics.

■ 28. In § 192.517, the introductory text of paragraph (a) is revised to read as follows:

§ 192.517 Records.

(a) Each operator must make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505, 192.506, and 192.507. The record must contain at least the following information:

* * * * *

■ 29. In § 192.605, paragraph (b)(5) is revised to read as follows:

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(b) * * *

(5) Operating pipeline controls and systems and operating and maintaining pressure relieving or pressure limiting devices, including those for starting up and shutting down any part of the pipeline, so that the MAOP limit as prescribed by this part cannot be exceeded by more than the margin (build-up) allowed for operation of pressure relieving devices or pressure-limiting or control devices as specified in § 192.201, 192.620(e), 192.731, 192.739, or 192.743, whichever applies.

* * * * *

■ 30. Section 192.607 is added to read as follows:

§ 192.607 Verification of pipeline material: Onshore steel transmission pipelines.

(a) *Applicable locations.* Each operator must follow the requirements of paragraphs (b) through (d) of this section for each segment of onshore, steel, gas transmission pipeline installed before *[effective date of the final rule]* that does not have reliable, traceable, verifiable, and complete material documentation records for line pipe, valves, flanges, and components and meets any of the following conditions:

(1) The pipeline is located in a High Consequence Area as defined in § 192.903*;* or

(2) The pipeline is located in a class 3 or class 4 location.

(b) *Material documentation plan.* Each operator must prepare a material documentation plan to implement all actions required by this section by *[date 180 days after the effective date of the final rule].*

(c) *Material documentation.* Each operator must have reliable, traceable, verifiable, and complete records documenting the following:

(1) For line pipe and fittings, records must document diameter, wall thickness, grade (yield strength and ultimate tensile strength), chemical composition, seam type, coating type, and manufacturing specification.

(2) For valves, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating. For valves with pipe weld ends, records must document the valve material grade and weld end bevel condition to ensure compatibility with pipe end conditions;

(3) For flanges, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating, and the material grade and weld end bevel condition to ensure compatibility with pipe end conditions;

(4) For components, records must document the applicable standards to which the component was manufactured to ensure pressure rating compatibility.

(d) *Verification of material properties.* For any material documentation records for line pipe, valves, flanges, and components specified in paragraph (c) of this section that are not available, the operator must take the following actions to determine and verify the physical characteristics.

(1) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for line pipe at all above ground locations.

(2) Develop and implement procedures for conducting destructive tests, examinations, and assessments for buried line pipe at all excavations associated with replacements or relocations of pipe segments that are removed from service.

(3) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for buried line pipe at all excavations associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, or any other reason for which the pipe segment is exposed, except for segments exposed during excavation activities that are in compliance with § 192.614, until completion of the minimum number of excavations as follows:

(i) The operator must define a separate population of undocumented or inadequately documented pipeline segments for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a two year interval) and construction dates (within a two year interval).

(ii) Assessments must be proportionally spaced throughout the pipeline segment. Each length of the pipeline segment equal to 10 percent of the total length must contain 10 percent of the total number of required excavations, *e.g.* a 200 mile population would require 15 excavations for each 20 miles. For each population defined according to paragraph (d)(3)(i) of this section, the minimum number of excavations at which line pipe must be tested to verify pipeline material properties is the lesser of the following:

(A) 150 excavations; or

(B) If the segment is less than 150 miles, a number of excavations equal to the population's pipeline mileage (*i.e.,* one set of properties per mile), rounded up to the nearest whole number. The mileage for this calculation is the cumulative mileage of pipeline segments in the population without reliable, traceable, verifiable, and complete material documentation.

(iii) At each excavation, tests for material properties must determine diameter, wall thickness, yield strength, ultimate tensile strength, Charpy v-notch toughness (where required for failure pressure and crack growth analysis), chemical properties, seam type, coating type, and must test for the presence of stress corrosion cracking, seam cracking, or selective seam weld corrosion using ultrasonic inspection, magnetic particle, liquid penetrant, or other appropriate non-destructive examination techniques. Determination of material property values must

conservatively account for measurement inaccuracy and uncertainty based upon comparison with destructive test results using unity charts.

(iv) If non-destructive tests are performed to determine strength or chemical composition, the operator must use methods, tools, procedures, and techniques that have been independently validated by subject matter experts in metallurgy and fracture mechanics to produce results that are accurate within 10% of the actual value with 95% confidence for strength values, within 25% of the actual value with 85% confidence for carbon percentage and within 20% of the actual value with 90% confidence for manganese, chromium, molybdenum, and vanadium percentage for the grade of steel being tested.

(v) The minimum number of test locations at each excavation or above-ground location is based on the number of joints of line pipe exposed, as follows:

(A) 10 joints or less: one set of tests for each joint.

(B) 11 to 100 joints: one set of tests for each five joints, but not less than 10 sets of tests.

(C) Over 100 joints: one set of tests for each 10 joints, but not less than 20 sets of tests.

(vi) For non-destructive tests, at each test location, a set of material properties tests must be conducted at a minimum of five places in each circumferential quadrant of the pipe for a minimum total of 20 test readings at each pipe cylinder location.

(vii) For destructive tests, at each test location, a set of materials properties tests must be conducted on each circumferential quadrant of a test pipe cylinder removed from each location, for a minimum total of four tests at each location.

(viii) If the results of all tests conducted in accordance with paragraphs (d)(3)(i) and (ii) of this section verify that material properties are consistent with all available information for each population, then no additional excavations are necessary. However, if the test results identify line pipe with properties that are not consistent with existing expectations based on all available information for each population, then the operator must perform tests at additional excavations. The minimum number of excavations that must be tested depends on the number of inconsistencies observed between as-found tests and available operator records, in accordance with the following table:

Number of excavations with inconsistency between test results and existing expectations based on all available information for each population	Minimum number of total required excavations for population. The lesser of:
0	150 (or pipeline mileage)
1	225 (or pipeline mileage times 1.5)
2	300 (or pipeline mileage times 2)
>2	350 (or pipeline mileage times 2.3)

(ix) The tests conducted for a single excavation according to the requirements of paragraphs (d)(3)(iii) through (vii) of this section count as one sample under the sampling requirements of paragraphs (d)(3)(i), (ii), and (viii) of this section.

(4) For mainline pipeline components other than line pipe, the operator must develop and implement procedures for establishing and documenting the ANSI rating and material grade (to assure compatibility with pipe ends).

(i) Materials in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, operator piping, or cross-connections with isolation valves from the mainline pipeline are not required to be tested for chemical and mechanical properties.

(ii) Verification of mainline material properties is required for non-line pipe components, including but not limited to, valves, flanges, fittings, fabricated assemblies, and other pressure retaining components appurtenances that are:

(A) 2-inch nominal diameter and larger; or

(B) Material grades greater than 42,000 psi (X–42); or

(C) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

(iii) Procedures for establishing material properties for non-line pipe components where records are inadequate must be based upon documented manufacturing specifications. Where specifications are not known, usage of manufacturer's stamped or tagged material pressure ratings and material type may be used to establish pressure rating. The operator must document the basis of the material properties established using such procedures.

(5) The material properties determined from the destructive or non-destructive tests required by this section cannot be used to raise the original grade or specification of the material, which must be based upon the applicable standard referenced in § 192.7.

(6) If conditions make material verification by the above methods impracticable or if the operator chooses to use ''other technology'' or ''new technology'' (alternative technical evaluation process plan), the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph § 192.624(e) of this section. The operator must submit the alternative technical evaluation process plan to the Associate Administrator of Pipeline Safety with the notification and must obtain a ''no objection letter'' from the Associate Administrator of Pipeline Safety prior to usage of an alternative evaluation process.

■ 31. In § 192.613, paragraph (c) is added to read as follows:

§ 192.613 Continuing surveillance.

* * * * *

(c) Following an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event that has the likelihood of damage to infrastructure, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

(1) *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 damage and the need for the additional assessments required under the introductory text of paragraph (c) in this section.

(2) *Time period.* The inspection required under the introductory text of paragraph (c) 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, including availability of personnel and equipment, required to perform the inspection as determined under paragraph (c)(1) of this section, whichever is sooner.

(3) *Remedial action.* An operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required under the introductory text of paragraph (c) in this section. Such

actions might include, but are not limited to:

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

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

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

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

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

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

■ 32. In § 192.619, paragraphs (a)(2) through (4) are revised and paragraphs (e) and (f) are added to read as follows:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) * * *

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors [1], segment—			
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970) and before *[effective date of the final rule]*	Installed after *[effective date of the final rule minus 1 day]*	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1] For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than § 192.612) after April 13, 2006 but before *[effective date of the final rule]*.	March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
—Onshore gathering line that first became subject to this part (other than § 192.612) on or after *[effective date of the final rule]*.	*[date one year after effective date of the final rule],* or date line becomes subject to this part, whichever is later.	
—Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.	March 15, 2006, or date line becomes subject to this part, whichever is later.	
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering material records, including material properties verified in accordance with § 192.607, and the history of the segment, particularly known corrosion and the actual operating pressure.

* * * * *

(e) Notwithstanding the requirements in paragraphs (a) through (d) of this section, onshore steel transmission pipelines that meet the criteria specified in § 192.624(a) must establish and document the maximum allowable operating pressure in accordance with § 192.624 using one or more of the following:

(1) Method 1: Pressure Test—Pressure test in accordance with § 192.624(c)(1)(i) or spike hydrostatic pressure test in accordance with § 192.624(c)(1)(ii), as applicable;

(2) Method 2: Pressure Reduction—Reduction in pipeline maximum allowable operating pressure in accordance with § 192.624(c)(2);

(3) Method 3: Engineering Critical Assessment—Engineering assessment and analysis activities in accordance with § 192.624(c)(3);

(4) Method 4: Pipe Replacement—Replacement of the pipeline segment in accordance with § 192.624(c)(4);

(5) Method 5: Pressure Reduction for Segments with Small PIR and Diameter—Reduction of maximum allowable operating pressure and other preventive measures for pipeline segments with small PIRs and diameters, in accordance with § 192.624(c)(5); or

(6) Method 6: Alternative Technology—Alternative procedure in accordance with § 192.624(c)(6).

(f) Operators must maintain all records necessary to establish and document the MAOP of each pipeline as long as the pipe or pipeline remains in service. Records that establish the pipeline MAOP, include, but are not limited to, design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data. Records must be reliable, traceable, verifiable, and complete.

■ 33. Section 192.624 is added to read as follows:

§ 192.624 Maximum allowable operating pressure verification: Onshore steel transmission pipelines.

(a) *Applicable locations.* The operator of a pipeline segment meeting any of the following conditions must establish the maximum allowable operating pressure using one or more of the methods specified in § 192.624(c)(1) through (6):

(1) The pipeline segment has experienced a reportable in-service incident, as defined in § 191.3 of this chapter, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking and the pipeline segment is located in one of the following locations:

(i) A high consequence area as defined in § 192.903;

(ii) A class 3 or class 4 location; or

(iii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

(2) Pressure test records necessary to establish maximum allowable operating pressure per subpart J for the pipeline segment, including, but not limited to, records required by § 192.517(a), are not reliable, traceable, verifiable, and complete and the pipeline is located in one of the following locations:

(i) A high consequence area as defined in § 192.903; or

(ii) A class 3 or class 4 location

(3) The pipeline segment maximum allowable operating pressure was established in accordance with § 192.619(c) before *[effective date of the final rule*] and is located in one of the following areas:

(i) A high consequence area as defined in § 192.903;

(ii) A class 3 or class 4 location; or

(iii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

(b) *Completion date.* For pipelines installed before [*effective date of the final rule*], all actions required by this section must be completed according to the following schedule:

(1) The operator must develop and document a plan for completion of all actions required by this section by *[date 1 year after effective date of the final rule].*

(2) The operator must complete all actions required by this section on at least 50% of the mileage of locations that meet the conditions of § 192.624(a) by *[date 8 years after effective date of the final rule].*

(3) The operator must complete all actions required by this section on 100% of the mileage of locations that meet the conditions of § 192.624(a) by *[date 15 years after effective date of the final rule].*

(4) If operational and environmental constraints limit the operator from meeting the deadlines in § 192.614(b)(2) and (3), the operator may petition for an extension of the completion deadlines by up to one year, upon submittal of a notification to the Associate Administrator of the Office of Pipeline Safety in accordance with paragraph (e) of this section. The notification must include an up-to-date plan for completing all actions in accordance with paragraph (b)(1) of this section, the reason for the requested extension, current status, proposed completion date, remediation activities outstanding, and any needed temporary safety measures to mitigate the impact on safety.

(c) *Maximum allowable operating pressure determination.* The operator of a pipeline segment meeting the criteria in paragraph (a) of this section must establish its maximum allowable operating pressure using one of the following methods:

(1) *Method 1: Pressure test.*(i) Perform a pressure test in accordance with § 192.505(c). The maximum allowable operating pressure will be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

(ii) If the pipeline segment includes legacy pipe or was constructed using legacy construction techniques or the pipeline has experienced an incident, as defined by § 191.3 of this chapter, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect, or a crack or crack-like defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking, then the operator must perform a spike pressure test in accordance with § 192.506. The maximum allowable operating pressure will be equal to the test pressure specified in § 192.506(c) divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

(iii) If the operator has reason to believe any pipeline segment may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph (d) of this section.

(2) *Method 2: Pressure reduction.* The pipeline maximum allowable operating pressure will be no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding *[effective date of the final rule]* divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest pressure value for the entire segment or using the operating pressure gradient (*i.e.,* the location-specific operating pressure at each location).

(i) Where the pipeline segment has had a class location change in accordance with § 192.611 and pipe material and pressure test records are not available, the operator must reduce the pipeline segment MAOP as follows:

(A) For segments where a class location changed from 1 to 2, from 2 to 3, or from 3 to 4, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding *[effective date of the final rule],* divided by 1.39 for class 1 to 2, 1.67 for class 2 to 3, and 2.00 for class 3 to 4.

(B) For segments where a class location changed from 1 to 3, reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding *[effective date of the final rule],* divided by 2.00.

(ii) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph (d) of this section.

(iii) Future uprating of the segment in accordance with subpart K of this part is allowed if the maximum allowable operating pressure is established using Method 2 described in paragraph (c)(2) of this section.

(iv) If an operator elects to use Method 2 described in paragraph (c)(2) of this section, but desires to use a less conservative pressure reduction factor, the operator must notify PHMSA in accordance with paragraph (e) of this section no later than seven calendar days after establishing the reduced maximum allowable operating pressure.

The notification must include the following details:

(A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with paragraph (d) of this section;

(C) Justification that establishing maximum allowable operating pressure by another method allowed by this section is impractical;

(D) Justification that the reduced maximum allowable operating pressure determined by the operator is safe based on analysis of the condition of the pipeline segment, including material records, material properties verified in accordance § 192.607, and the history of the segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned.

(E) Planned duration for operating at the requested maximum allowable operating pressure, long term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts in metallurgy and fracture mechanics.

(3) *Method 3: Engineering critical assessment.* Conduct an engineering critical assessment and analysis (ECA) to establish the material condition of the segment and maximum allowable operating pressure. An ECA is an analytical procedure, based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections. The ECA must assess: threats; loadings and operational circumstances relevant to those threats including along the right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; initial and final defect size relevance. The ECA must quantify the coupled effects of any defect in the pipeline.

(i) *ECA analysis.* (A) The ECA must integrate and analyze the results of the material documentation program required by § 192.607, if applicable, and the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including but not limited to close interval surveys, coating surveys, and interference surveys required by subpart I of this part, root cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by § 192.710 and subpart O of this part.

(B) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure (PFP) of each defect. The ECA must use the techniques and procedures in Battelle Final Reports (''Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications''—Task 1.4), Report No. 13–002 (''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams''—Subtask 2.4), Report No. 13–021 (''Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue''—Subtask 2.5) and (''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1''—Task 4.5) (incorporated by reference, *see* § 192.7) or other technically proven methods including but not limited to API RP 579–1/ASME FFS–1, June 5, 2007, (API 579–1, Second Edition)—Level II or Level III, CorLas™, or PAFFC. The ECA must use conservative assumptions for crack dimensions (length and depth) and failure mode (ductile, brittle, or both) for the microstructure, location, type of defect, and operating conditions (which includes pressure cycling). If actual material toughness is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must determine a Charpy v-notch toughness based upon the material documentation program specified in § 192.607 or use conservative values for Charpy v-notch toughness as follows: body toughness of less than or equal to 5.0 ft-lb and seam toughness of less than or equal to 1 ft-lb.

(C) The ECA must analyze any metal loss defects not associated with a dent including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe to determine the predicted failure pressure (PFP). ASME/ANSI B31G (incorporated by reference, see § 192.7) or AGA Pipeline Research Committee Project PR–3–805 (''RSTRENG,'' incorporated by reference, see § 192.7) must be used for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth). When determining PFP for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607.

(D) The ECA must analyze interacting defects to conservatively determine the most limiting PFP for interacting defects. Examples include but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

(E) The maximum allowable operating pressure must be established at the lowest PFP for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).

(ii) *Use of prior pressure test.* If pressure test records as described in subpart J of this part and § 192.624(c)(1) exist for the segment, then an in-line inspection program is not required, provided that the remaining life of the most severe defects that could have survived the pressure test have been calculated and a re-assessment interval has been established. The appropriate retest interval and periodic tests for time-dependent threats must be determined in accordance with the methodology in § 192.624(d) *Fracture mechanics modeling for failure stress and crack growth analysis.*

(iii) *In-line inspection.* If the segment does not have records for a pressure test in accordance with subpart J of this part and § 192.624(c)(1), the operator must develop and implement an inline inspection (ILI) program using tools that can detect wall loss, deformation from

dents, wrinkle bends, ovalities, expansion, seam defects including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking. At a minimum, the operator must conduct an assessment using high resolution magnetic flux leakage (MFL) tool, a high resolution deformation tool, and either an electromagnetic acoustic transducer (EMAT) or ultrasonic testing (UT) tool.

(A) In lieu of the tools specified in paragraph § 192.624(c)(3)(i), an operator may use ''other technology'' if it is validated by a subject matter expert in metallurgy and fracture mechanics to produce an equivalent understanding of the condition of the pipe. If an operator elects to use ''other technology,'' it must notify the Associate Administrator of Pipeline Safety, at least 180 days prior to use, in accordance with paragraph (e) of this section and receive a ''no objection letter'' from the Associate Administrator of Pipeline Safety prior to its usage. The ''other technology'' notification must have:

(*1*) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments including characterization of defect size crack assessments (length, depth, and volumetric); and

(*2*) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and remediate defects discovered.

(B) If the operator has information that indicates a pipeline includes segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.

(C) If the pipeline has had a reportable incident, as defined in § 192.3, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with paragraph § 192.624(c)(3)(iii) includes an engineering evaluation program to analyze the susceptibility of girth weld failure due to lateral stresses.

(D) Inline inspection must be performed in accordance with § 192.493.

(E) All MFL and deformation tools used must have been validated to characterize the size of defects within 10% of the actual dimensions with 90% confidence. All EMAT or UT tools must have been validated to characterize the size of cracks, both length and depth, within 20% of the actual dimensions with 80% confidence, with like-similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.

(F) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O of this part, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the type defects and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.

(G) Anomalies detected by ILI assessments must be repaired in accordance with applicable repair criteria in §§ 192.713 and 192.933.

(iv) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.624(d).

(4) *Method 4: Pipe replacement.* Replace the pipeline segment.

(5) *Method 5: Pressure reduction for segments with small potential impact radius and diameter.* Pipelines with a maximum allowable operating pressure less than 30 percent of specified minimum yield strength, a potential impact radius (PIR) less than or equal to 150 feet, nominal diameter equal to or less than 8-inches, and which cannot be assessed using inline inspection or pressure test, may establish the maximum allowable operating pressure as follows:

(i) Reduce the pipeline maximum allowable operating pressure to no greater than the highest actual operating pressure sustained by the pipeline during 18 months preceding *[effective date of the final rule],* divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of eight hours during one continuous 30-day period. The reduced maximum allowable operating pressure must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire segment or the operating pressure gradient (*i.e.,* the location specific operating pressure at each location);

(ii) Conduct external corrosion direct assessment in accordance with § 192.925, and internal corrosion direct assessment in accordance with § 192.927;

(iii) Develop and implement procedures for conducting non-destructive tests, examinations, and assessments for cracks and crack-like defects, including but not limited to stress corrosion cracking, selective seam weld corrosion, girth weld cracks, and seam defects, for pipe at all excavations associated with anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, or any other reason for which the pipe segment is exposed, except for segments exposed during excavation activities that are in compliance with § 192.614;

(iv) Conduct monthly patrols in Class 1 and 2 locations, at an interval not to exceed 45 days; weekly patrols in Class 3 locations not to exceed 10 days; and semi-weekly patrols in Class 4 locations, at an interval not to exceed six days, in accordance with § 192.705;

(v) Conduct monthly, instrumented leakage surveys in Class 1 and 2 locations, at intervals not to exceed 45 days; weekly leakage surveys in Class 3 locations at intervals not to exceed 10 days; and semi-weekly leakage surveys in Class 4 locations, at intervals not to exceed six days, in accordance with § 192.706; and

(vi) Odorize gas transported in the segment, in accordance with § 192.625;

(vii) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.624(d).

(viii) Under Method 5 described in paragraph (c)(5) of this section, future uprating of the segment in accordance with subpart K of this part is allowed.

(6) *Method 6: Alternative technology.* Operators may use an alternative technical evaluation process that provides a sound engineering basis for establishing maximum allowable operating pressure. If an operator elects to use alternative technology, the

operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph (e) of this section. The operator must submit the alternative technical evaluation to PHMSA with the notification and obtain a ''no objection letter'' from the Associate Administrator of Pipeline Safety prior to usage of alternative technology. The notification must include the following details:

(i) Descriptions of the technology or technologies to be used for tests, examinations, and assessments, establishment of material properties, and analytical techniques, with like-similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.

(ii) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;

(iii) Methodology and criteria used to determine reassessment period or need for a reassessment including references to applicable regulations from this part and industry standards;

(iv) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;

(v) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of PFP quantified as a fraction of specified minimum yield strength;

(vi) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph (d) of this section;

(vii) Remediation methods with proven technical practice;

(viii) Schedules for assessments and remediation;

(ix) Operational monitoring procedures;

(x) Methodology and criteria used to justify and establish the maximum allowable operating pressure; and

(xi) Documentation requirements for the operator's process, including records to be generated.

(d) *Fracture mechanics modeling for failure stress and crack growth analysis.* (1) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must perform fracture mechanics modeling for failure stress pressure and crack growth analysis to determine the remaining life of the pipeline at the maximum allowable operating pressure based on the applicable test pressures in accordance with § 192.506 including the remaining crack flaw size in the pipeline segment, any pipe failure or leak mechanisms identified during pressure testing, pipe characteristics, material toughness, failure mechanism for the microstructure(ductile and brittle or both), location and type of defect, operating environment, and operating conditions including pressure cycling. Fatigue analysis must be performed using a recognized form of the Paris Law as specified in Battelle's Final Report No. 13–021; Subtask 2.5 (incorporated by reference, see § 192.7) or other technically appropriate engineering methodology validated by a subject matter expert in metallurgy and fracture mechanics to give conservative predictions of flaw growth and remaining life. When assessing other degradation processes, the analysis must be performed using recognized rate equations whose applicability and validity is demonstrated for the case being evaluated. For cases involving calculation of the critical flaw size, conservative remaining life analysis must assess the smallest critical sizes and use a lower-bound toughness. For cases dealing with an estimating of the defect sizes that would survive a hydro test pressure, conservative remaining life analysis that must assess the largest surviving sizes and use upper-bound values of material strength and toughness. The analysis must include a sensitivity analysis to determine conservative estimates of time to failure for cracks. Material strength and toughness values used must reflect the local conditions for growth, and use data that is case specific to estimate the range of strength and toughness for such analysis. When the strength and toughness and limits on their ranges are unknown, the analysis must assume material strength and fracture toughness levels corresponding to the type of assessment being performed, as follows:

(i) For an assessment using a hydrostatic pressure test use a full size equivalent Charpy upper-shelf energy level of 120 ft-lb and a flow stress equal to the minimum specified ultimate tensile strength of the base pipe material. The purpose of using the high level of Charpy energy and flow stress (equal to the ultimate tensile strength) is for an operator to calculate the largest defects that could have survived a given level of hydrostatic test. The resulting maximum-size defects lead to the shortened predicted times to failure,

(ii) For ILI assessments unless actual ranges of values of strength and toughness are known, the analysis must use the specified minimum yield strength and the specified minimum ultimate tensile strength and Charpy toughness valves lower than or equal to: 5.0 ft-lb for body cracks; 1.0 ft-lb for ERW seam bond line defects such as cold weld, lack of fusion, and selective seam weld corrosion defects.

(iii) The sensitivity analysis to determine the time to failure for a crack must include operating history, pressure tests, pipe geometry, wall thickness, strength level, flow stress, and operating environment for the pipe segment being assessed, including at a minimum the role of the pressure-cycle spectrum.

(2) If actual material toughness is not known or not adequately documented for fracture mechanics modeling for failure stress pressure, the operator must use a conservative Charpy energy value to determine the toughness based upon the material documentation program specified in § 192.607; or use maximum Charpy energy values of 5.0 ft-lb for body cracks; 1.0 ft-lb for cold weld, lack of fusion, and selective seam weld corrosion defects as documented in Battelle Final Reports (''Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications''—Task 1.4), No. 13–002 (''Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams''—Subtask 2.4), Report No. 13–021 (''Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue''—Subtask 2.5) and (''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1''—Task 4.5) (incorporated by reference, *see* § 192.7); or other appropriate technology or technical publications that an operator demonstrates can provide a conservative Charpy energy values of the crack-related conditions of the line pipe.

(3) The analysis must account for metallurgical properties at the location being analyzed (such as in the properties of the parent pipe, weld heat affected zone, or weld metal bond line), and 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. Appropriate fracture

mechanics modeling for failure stress pressures in the brittle failure mode is the Raju/Newman Model (Task 4.5) and for the ductile failure mode is the Modified LnSec (Task 4.5) and Raju/Newman Models or other proven-equivalent engineering fracture mechanics models for determining conservative failure pressures may be used.

(4) If the predicted remaining life of the pipeline calculated by this analysis is 5 years or less, then the operator must perform a pressure test in accordance with paragraph (c)(1) of this section or reduce the maximum allowable operating pressure of the pipeline in accordance with paragraph (c)(2) of this section to establish the maximum allowable operating pressure within 1-year of analysis;

(5) The operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired, but within 15 years. The operator must determine and document if further pressure tests or use of other methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired. If the analysis results show that a 50% remaining life reduction does not give a sufficient safety factor based upon technical evaluations then a more conservative remaining life safety factor must be used.

(6) The analysis required by this paragraph (d) of this section must be reviewed and confirmed by a subject matter expert in both metallurgy and fracture mechanics.

(e) *Notifications.* An operator must submit all notifications required by this section to the Associate Administrator for Pipeline Safety, by:

(1) Sending the notification to the Office of Pipeline Safety, Pipeline and Hazardous Material Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP–10, 1200 New Jersey Avenue SE., Washington, DC 20590–0001;

(2) Sending the notification to the Information Resources Manager by facsimile to (202) 366–7128; or

(3) Sending the notification to the Information Resources Manager by email to *InformationResourcesManager@dot.gov*.

(4) An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

(f) *Records.* Each operator must keep for the life of the pipeline reliable, traceable, verifiable, and complete records of the investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions made in accordance with the requirements of this section.

■ 34. Section 192.710 is added to read as follows:

§ 192.710 Pipeline assessments.

(a) *Applicability.* (1) This section applies to onshore transmission pipeline segments that are located in:

(i) A class 3 or class 4 location; or

(ii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (*i.e.,* ''smart pigs'').

(2) This section does not apply to a pipeline segment located in a high consequence area as defined in § 192.903.

(b) *General.* (1) An operator must perform initial assessments in accordance with this section no later than *[date 15 years after effective date of the final rule]* and periodic reassessments every 20 years thereafter, or a shorter reassessment internal based upon the type anomaly, operational, material, and environmental conditions found on the pipeline segment, or as otherwise necessary to ensure public safety.

(2) *Prior assessment.* An operator may use a prior assessment conducted before *[effective date of the final rule]* as an initial assessment for the segment, if the assessment meets the subpart O of this part requirements for in-line inspection. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(1) of this section.

(3) *MAOP verification.* An operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(c) *Assessment method.* The initial assessments and the reassessments required by paragraph (b) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline is susceptible and must be performed using one or more of the following methods:

(1) Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots, and any other threats to which the segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;

(2) Pressure test conducted in accordance with subpart J of this part. The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, manufacturing and related defect threats, including defective pipe and pipe seams, dents and other forms of mechanical damage;

(3) ''Spike'' hydrostatic pressure test in accordance with § 192.506;

(4) Excavation and *in situ* direct examination by means of visual examination and direct measurement and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the methods specified in paragraphs (d)(1) through (5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 or 192.929; or

(7) Other technology or technologies that an operator demonstrates can provide an equivalent understanding of the line pipe for each of the threats to which the pipeline is susceptible.

(8) For segments with MAOP less than 30% of the SMYS, an operator must assess for the threats of external and internal corrosion, as follows:

(i) *External corrosion.* An operator must take one of the following actions to address external corrosion on a low stress segment:

(A) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe, an operator must perform an indirect assessment (*i.e.* indirect examination

tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) at least every seven years on the segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(B) *Unprotected pipe or cathodically protected pipe where indirect assessments are impractical.* To address the threat of external corrosion on unprotected pipe or cathodically protected pipe where indirect assessments are impractical, an operator must—

(*1*) Conduct leakage surveys as required by § 192.706 at 4-month intervals; and

(*2*) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(ii) *Internal corrosion.* To address the threat of internal corrosion on a low stress segment, an operator must—

(A) Conduct a gas analysis for corrosive agents at least twice each calendar year;

(B) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a segment; and

(C) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(8)(ii)(A) and (B) of this section with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

(d) *Data analysis.* A person qualified by knowledge, training, and experience must analyze the data obtained from an assessment performed under paragraph (b) of this section to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing anomalies.

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

(f) *Remediation.* An operator must comply with the requirements in § 192.713 if a condition that could adversely affect the safe operation of a pipeline is discovered.

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

■ 35. In § 192.711, paragraph (b)(1) is revised to read as follows:

§ 192.711 Transmission lines: General requirements for repair procedures.

* * * * *

(b) * * *

(1) *Non integrity management repairs.* Whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered under subpart O of this part, Gas Transmission Pipeline Integrity Management, it must correct the condition as prescribed in § 192.713. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator must reduce the operating pressure to a level not exceeding 80% of the operating pressure at the time the condition was discovered and take additional immediate temporary measures in accordance with paragraph (a) of this section to protect persons or property. The operator must make permanent repairs as soon as feasible.

* * * * *

■ 36. Section 192.713 is revised to read as follows:

§ 192.713 Transmission lines: Permanent field repair of imperfections and damages.

(a) *This section applies to transmission lines.* Line segments that are located in high consequence areas, as defined in § 192.903, must also comply with applicable actions specified by the integrity management requirements in subpart O of this part.

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

(c) *Repair.* Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(d) *Remediation schedule.* For pipelines not located in high consequence areas, an operator must complete the remediation of a condition according to the following schedule:

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

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in § 192.7(c). Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

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

(iv) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high frequency electric resistance welding or by electric flash welding.

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

(vi) Any indication of significant selective seam weld corrosion (SSWC).

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

(2) Until the remediation of a condition specified in paragraph (d)(1) of this section is complete, an operator must reduce the operating pressure of the affected pipeline to the lower of:

(i) A level that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, determined using 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)) (''RSTRENG,'' incorporated by reference, see § 192.7) for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used. If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607; or

(ii) 80% of pressure at the time of discovery, whichever is lower.

(3) *Two-year conditions.* An operator must repair the following conditions within two years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than nominal pipe size (NPS) 12).

(ii) 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 at a longitudinal or helical (spiral) seam weld.

(iii) A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio (FPR) at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations. This calculation must adequately account for the uncertainty associated with the accuracy of the tool used to perform the assessment.

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

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

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

(vii) Any indication of crack or crack-like defect other than an immediate condition.

(4) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than nominal pipe size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(e) *Other conditions.* Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules and methods defined in the operator's Operating and Maintenance procedures.

(f) *In situ direct examination of crack defects.* Whenever required by this part, operators must perform direct examination of known locations of cracks or crack-like defects using inverse wave field extrapolation (IWEX), phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks (equal to or less than 0.008 inches). In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, 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. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

■ 37. Section 192.750 is added to read as follows:

§ 192.750 Launcher and receiver safety.

Any launcher or receiver used after *[date 6 months after effective date of the final rule],* must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. The operator must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent opening of the barrel closure or flange, or prevent insertion or removal of in-line inspection tools, scrapers, or spheres, if pressure has not been relieved.

■ 38. In § 192.911, paragraph (k) is revised to read as follows:

§ 192.911 What are the elements of an integrity management program?

* * * * *

(k) A management of change process as required by § 192.13(d).

* * * * *

■ 39. In § 192.917, paragraphs (a), (b), (c), (d), (e)(2), (e)(3), and (e)(4) are revised to read as follows:

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 2, which are grouped under the following four threats:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Stable threats, such as manufacturing, welding/fabrication, or equipment defects;

(3) Time independent threats such as third party/mechanical damage, incorrect operational procedure, weather related and outside force, including consideration of seismicity, geology, and soil stability of the area; and

(4) Human error such as operational mishaps and design and construction mistakes.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather, verify, validate, and integrate existing data and

information on the entire pipeline that could be relevant to the covered segment. In performing data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in paragraph (b)(1) of this section and appendix A to ASME/ANSI B31.8S. The evaluation must analyze both the covered segment and similar non-covered segments, and must:

(1) Integrate information about pipeline attributes and other relevant information, including, but not limited to:

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

(ii) Manufacturer and manufacturing date, including manufacturing data and records;

(iii) Material properties including, but not limited to, diameter, wall thickness, grade, seam type, hardness, toughness, hard spots, and chemical composition;

(iv) Equipment properties;

(v) Year of installation;

(vi) Bending method;

(vii) Joining method, including process and inspection results;

(viii) Depth of cover surveys including stream and river crossings, navigable waterways, and beach approaches;

(ix) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;

(x) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;

(xi) Pipe coating methods (both manufactured and field applied) including method or process used to apply girth weld coating, inspection reports, and coating repairs;

(xii) Soil, backfill;

(xiii) Construction inspection reports, including but not limited to:

(A) Girth weld non-destructive examinations;

(B) Post backfill coating surveys;

(C) Coating inspection (''jeeping'') reports;

(xiv) Cathodic protection installed, including but not limited to type and location;

(xv) Coating type;

(xvi) Gas quality;

(xvii) Flow rate;

(xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);

(xix) Class location;

(xx) Leak and failure history including any in-service ruptures or leaks from incident reports, abnormal operations, safety related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences;

(xxi) Coating condition;

(xxii) CP system performance;

(xxiii) Pipe wall temperature;

(xxiv) Pipe operational and maintenance inspection reports, including but not limited to:

(A) Data gathered through integrity assessments required under this part, including but not limited to in-line inspections, pressure tests, direct assessment, guided wave ultrasonic testing, or other methods;

(B) Close interval survey (CIS) and electrical survey results;

(C) Cathodic protection (CP) rectifier readings;

(D) CP test point survey readings and locations;

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

(F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including but not limited to direct current voltage gradient or alternating current voltage gradient inspections;

(G) Results of examinations of exposed portions of buried pipelines (*e.g.,* pipe and pipe coating condition, see § 192.459), including the results of any non-destructive examinations of the pipe, seam or girth weld, *i.e.* bell hole inspections;

(H) Stress corrosion cracking (SCC) excavations and findings;

(I) Selective seam weld corrosion (SSWC) excavations and findings;

(J) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;

(xxv) Outer Diameter/Inner Diameter corrosion monitoring;

(xxvi) Operating pressure history and pressure fluctuations, including analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;

(xxvii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;

(xxviii) Encroachments and right-of-way activity, including but not limited to, one-call data, pipe exposures resulting from encroachments, and excavation activities due to development or planned development along the pipeline;

(xxix) Repairs;

(xxx) Vandalism;

(xxxi) External forces;

(xxxii) Audits and reviews;

(xxxiii) Industry experience for incident, leak and failure history;

(xxxiv) Aerial photography;

(xxxv) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area; and

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

(2) Use objective, traceable, verified, and validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SMEs), the operator must employ measures to adequately correct any bias in SME input. Bias control measures may include training of SMEs and use of outside technical experts (independent expert reviews) to assess quality of processes and the judgment of SMEs. Operator must document the names of all SMEs and information submitted by the SMEs for the life of the pipeline.

(3) Identify and analyze spatial relationships among anomalous information (*e.g.,* corrosion coincident with foreign line crossings; evidence of pipeline damage where overhead imaging shows evidence of encroachment). Storing or recording the information in a common location, including a geographic information system (GIS), alone, is not sufficient; and

(4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

(c) *Risk assessment.* An operator must conduct a risk assessment that analyzes the identified threats and potential consequences of an incident for each covered segment. The risk assessment must include evaluation of the effects of interacting threats, including the potential for interactions of threats and anomalous conditions not previously evaluated. An operator must ensure validity of the methods used to conduct the risk assessment in light of incident, leak, and failure history and other historical information. Validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the

factors used to characterize both the probability of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed (§ 192.935) for each covered segment, and periodically evaluate the integrity of each covered pipeline segment (§ 192.937(b)). The risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas, including the consequences of the entire worst-case incident scenario from initial failure to incident termination;

(2) Analyze the likelihood of failure due to each individual threat or risk factor, and each unique combination of threats or risk factors that interact or simultaneously contribute to risk at a common location;

(3) Lead to better understanding of the nature of the threat, the failure mechanisms, the effectiveness of currently deployed risk mitigation activities, and how to prevent, mitigate, or reduce those risks;

(4) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and

(5) Evaluate the potential risk reduction associated with candidate risk reduction activities such as preventive and mitigative measures and reduced anomaly remediation and assessment intervals.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.

(e) * * *

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading conditions (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment. Fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis must be conducted in accordance with § 192.624(d) for cracks. Cyclic fatigue analysis must be annually, not to exceed 15 months.

(3) *Manufacturing and construction defects.* An operator must analyze the covered segment to determine the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to hydrostatic pressure testing satisfying the criteria of subpart J of this part of at least 1.25 times MAOP, and the segment has not experienced an in-service incident attributed to a manufacturing or construction defect since the date of the pressure test. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment, and must reconfirm or reestablish MAOP in accordance with § 192.624(c).

(i) The segment has experienced an in-service incident, as described in § 192.624(a)(1);

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe, pipe with seam factor less than 1.0 as defined in § 192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including, but not limited to pipe body cracking, seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years (including abnormal operation as defined in § 192.605(c)), or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment. Pipe with cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.624(c) and (d).

* * * * *

■ 40. In § 192.921, paragraph (a) is revised to read as follows:

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917). In addition, an operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(1) Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. A person qualified by knowledge, training, and experience must analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in table 3 of section 5 of ASME/ANSI B31.8S to justify an extended reassessment interval in accordance with § 192.939. The use of pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms, manufacturing and related defect threats, including defective pipe

and pipe seams, stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage;

(3) ''Spike'' hydrostatic pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for threats such as stress corrosion cracking, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects;

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI);

(5) Guided Wave Ultrasonic Testing (GWUT) conducted as described in Appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in § 192.925, 192.927, or 192.929; or

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with § 192.949 and receive a ''no objection letter'' from the Associate Administrator of Pipeline Safety. An operator must also notify the appropriate State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

* * * * *

■ 41. In § 192.923, paragraphs (b)(2) and (b)(3) are revised to read as follows:

§ 192.923 How is direct assessment used and for what threats?

* * * * *

(b) * * *

(2) NACE SP0206–2006 and § 192.927 if addressing internal corrosion (ICDA).

(3) NACE SP0204–2008 and § 192.929 if addressing stress corrosion cracking (SCCDA).

* * * * *

■ 42. In § 192.927, paragraphs (b) and (c) are revised to read as follows:

§ 192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

* * * * *

(b) *General requirements.* An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206–2006 (incorporated by reference, *see* § 192.7). The Dry Gas (DG) Internal Corrosion Direct Assessment (ICDA) process described in this section applies only for a segment of pipe transporting normally dry natural gas (see definition § 192.3), and not for a segment with electrolyte normally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment in accordance with § 192.921(a)(4) or § 192.937(c)(4).

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that meets all requirements and recommendations contained in NACE SP0206–2006 and that implements all four steps of the DG–ICDA process including pre-assessment, indirect inspection, detailed examination, and post-assessment. The plan must identify where all ICDA Regions with covered segments are located in the transmission system. An ICDA Region is a continuous length of pipe (including weld joints) uninterrupted by any significant change in water or flow characteristics that includes similar physical characteristics or operating history. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located in order to complete the assessment of the covered segment.

(1) *Preassessment.* An operator must comply with the requirements and recommendations in NACE SP0206–2006 in conducting the preassessment step of the ICDA process.

(2) *Indirect Inspection.* An operator must comply with the requirements and recommendations in NACE SP0206–2006, and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. Operators must explicitly document the results of its feasibility assessment as required by NACE SP0206–2006, Section 3.3; if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use pipeline specific data, exclusively. The use of assumed pipeline or operational data is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of data used to make those calculations, including but not limited to gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossing, river crossings, drains, valves, drips, etc.), topographical data, depth of cover, etc. The operator must select locations for direct examination, and establish the extent of pipe exposure needed (*i.e.,* the size of the bell hole), to explicitly account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

(3) *Detailed examination.* An operator must comply with the requirements and recommendations in NACE SP0206–2006 in conducting the detailed examination step of the ICDA process. In addition, on the first use of ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each covered segment associated with the ICDA Region and must perform a detailed examination for internal corrosion at each location using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion is found at any location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with § 192.933, if the condition is in a covered segment,

or in accordance with §§ 192.485 and 192.713 if the condition is not in a covered segment;

(ii) Expand the detailed examination program, whenever internal corrosion is discovered, to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (*e.g.,* sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined per paragraph (c)(3) of this section, two additional detailed examinations must be conducted within the covered segment; and

(iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region in which the corrosion was found and remediate identified instances of internal corrosion in accordance with § 192.933 or § 192.713, as appropriate.

(4) *Post-assessment evaluation and monitoring.* An operator must comply with the requirements and recommendations in NACE SP0206–2006 in performing the post assessment step of the ICDA process. In addition to the post-assessment requirements and recommendations in NACE SP0206–2006, the evaluation and monitoring process must also include—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in § 192.939. An operator must carry out this evaluation within a year of conducting an ICDA;

(ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (if the flow model cannot be validated, then ICDA is not feasible for the segment); and

(iii) Continually monitoring each ICDA region which contains a covered segment where internal corrosion has been identified by using techniques such as coupons or UT sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the ICDA region. At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not exceeding 7½ months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with § 192.933.

(A) Conduct excavations of, and detailed examinations at, locations downstream from where the electrolyte might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of § 192.478; or

(B) Assess the covered segment using ILI tools capable of detecting internal corrosion.

(5) *Other requirements*—The ICDA plan must also include the following:

(i) Criteria an operator will apply in making key decisions (*e.g.,* ICDA feasibility, definition of ICDA Regions and Sub-regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of § 192.933 may be limited to covered segments.

■ 43. Section 192.929 is revised to read as follows:

§ 192.929 What are the requirements for using direct assessment for stress corrosion cracking (SCCDA)?

(a) *Definition.* Stress corrosion cracking direct assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements.* An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must develop and follow an SCCDA plan that meets all requirements and recommendations contained in NACE SP0204–2008 and that implements all four steps of the SCCDA process including pre-assessment, indirect inspection, detailed examination and post-assessment. As specified in NACE SP0204–2008, Section 1.1.7, SCCDA is complementary with other inspection methods such as in-line inspection (ILI) or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. In addition, the plan must provide for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment in accordance with NACE SP0204–2008, sections 3 and 4, and table 1. This process must also include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204–2008 indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204–2008, section 5.3, and must include, at minimum, all data listed in NACE SP0204–2008, table 2. Further, the following factors must be analyzed as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment such as soil temperature, moisture, the presence or generation of carbon dioxide, and/or Cathodic Protection (CP).

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments.

(iii) The effects of variations in applied CP such as overprotection, CP loss for extended periods, and high negative potentials.

(iv) The effects of coatings that shield CP when disbonded from the pipe.

(v) Other factors which affect the mechanistic properties associated with SCC including but not limited to historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

(2) *Indirect inspection.* In addition to the requirements and recommendations of NACE SP0204–2008, section 4, the

plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using complementary measurement tools most appropriate for the pipeline segment based on the data gathering and integration step.

(3) *Direct examination.* In addition to the requirements and recommendations of NACE SP0204–2008, the plan's procedures for direct examination must provide for conducting a minimum of three direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur.

(4) *Remediation and mitigation.* If any indication of SCC is discovered in a segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Removing the pipe with SCC, remediating the pipe with a Type B sleeve, hydrostatic testing in accordance with (b)(4)(ii), below, or by grinding out the SCC defect and repairing the pipe. If grinding is used for repair, the repair procedure must include: Nondestructive testing for any remaining cracks or other defects; measuring remaining wall thickness; and the remaining strength of the pipe at the repair location must be determined using ASME/ANSI B31G or RSTRENG and must be sufficient to meet the design requirements of subpart C of this part. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.

(ii) Significant SCC must be mitigated using a hydrostatic testing program to a minimum test pressure equal to 105 percent of the specified minimum yield strength of the pipe for 30 minutes immediately followed by a pressure test in accordance with § 192.506, but not lower than 1.25 times MAOP. The test pressure for the entire sequence must be continuously maintained for at least 8 hours, in accordance with § 192.506 and must be above the minimum test factors in § 192.619(a)(2)(ii) or 192.620(a)(2)(ii), but not lower than 1.25 times maximum allowable operating pressure. Any test failures due to SCC must be repaired by replacement of the pipe segment, and the segment re-tested until the pipe passes the complete test without leakage. Pipe segments that have SCC present, but that pass the pressure test, may be repaired by grinding in accordance with paragraph (b)(4)(i) of this section.

(5) *Post assessment.* In addition to the requirements and recommendations of NACE SP0204–2008, sections 6.3, periodic reassessment, and 6.4, effectiveness of SCCDA, the operator's procedures for post assessment must include development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as on the mechanistic behavior of identified cracking. Reassessment intervals must comply with § 192.939. Factors that must be considered include, but are not limited to:

(i) Evaluation of discovered crack clusters during the direct examination step in accordance with NACE RP0204–2008, sections 5.3.5.7, 5.4, and 5.5;

(ii) Conditions conducive to creation of the carbonate-bicarbonate environment;

(iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

(iv) Operating temperature and pressure conditions including operating stress levels on the pipe;

(v) Cyclic loading conditions;

(vi) Mechanistic conditions that influence crack initiation and growth rates;

(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and.

(ix) Disbonded coatings that shield CP from the pipe.

■ 44. In § 192.933, paragraphs (a)(1), (b), (d)(1) are revised and paragraphs (d)(2)(iii) through (vii) are added to read as follows:

§ 192.933 What actions must be taken to address integrity issues?

(a) * * *

(1) *Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see § 192.7) or AGA Pipeline Research Council International, PR–3–805 (R–STRENG) (incorporated by reference, *see* § 192.7) to determine the safe operating pressure that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, or reduce the operating pressure to a level not exceeding 80 percent of the operating pressure at the time the condition was discovered. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607. An operator must notify PHMSA in accordance with § 192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

* * * * *

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period the operator must notify OPS, in accordance with § 192.949, and provide an expected date when adequate information will become available.

* * * * *

(d) * * *

(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) Calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly for any class location. Suitable

remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, *see* § 192.7), PRCI PR–3–805 (R–STRENG) (incorporated by reference, *see* § 192.7); or an alternative method of remaining strength calculation that will provide an equally conservative result. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.

(ii) A dent that has any indication of metal loss, cracking, or a stress riser.

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

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

(v) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency, or high frequency electric resistance welding or by electric flash welding.

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

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

(2) * * *.

(iii) A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations.

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

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

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

(vii) Any indication of crack or crack-like defect other than an immediate condition.

* * * * *

■ 45. In § 192.935, paragraphs (a), (b)(2), and (d)(3) are revised and paragraphs (f) and (g) are added to read as follows:

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

(a) *General requirements.* An operator must take additional measures beyond those already required by part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Such additional measures must be based on the risk analyses required by § 192.917, and must include, but are not limited to: Correction of the root causes of past incidents to prevent recurrence; establishing and implementing adequate operations and maintenance processes that could increase safety; establishing and deploying adequate resources for successful execution of preventive and mitigative measures; installing automatic shut-off valves or remote control valves; installing pressure transmitters on both sides of automatic shut-off valves and remote control valves that communicate with the pipeline control center; installing computerized monitoring and leak detection systems; replacing pipe segments with pipe of heavier wall thickness or higher strength; conducting additional right-of-way patrols; conducting hydrostatic tests in areas where material has quality issues or lost records; tests to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations including material property tests from removed pipe that is representative of the in-service pipeline; re-coating of damaged, poorly performing or disbonded coatings; applying additional depth-of-cover survey at roads, streams and rivers; remediating inadequate depth-of-cover; providing additional training to personnel on response procedures, conducting drills with local emergency responders; and implementing additional inspection and maintenance programs.

(b) * * *

(2) *Outside force damage.* If an operator determines that outside force (*e.g.,* earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, relocating the line, or geospatial, GIS, and deformation in-line inspections.

* * * * *

(d) * * *

(3) Perform semi-annual, instrumented leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where indirect assessments, *i.e.* indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent, are impractical).

* * * * *

(f) *Internal corrosion.* As an operator gains information about internal corrosion, it must enhance its internal corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to internal corrosion. At a minimum, as part of this enhancement, operators must—

(1) Monitor for, and mitigate the presence of, deleterious gas stream constituents.

(2) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and continuous gas quality monitoring equipment.

(3) At least once per quarter, use gas quality monitoring equipment that includes, but is not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling.

(4) Use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion.

(5) Use inhibitors when corrosive gas or corrosive liquids are present.

(6) Address potentially corrosive gas stream constituents as specified in § 192.478(a), where the volumes exceed these amounts over a 24-hour interval in the pipeline as follows:

(i) Limit carbon dioxide to three percent by volume;

(ii) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and

(iii) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas. If the hydrogen sulfide concentration is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.

(7) Review the program at least semi-annually based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.

(g) *External corrosion.* As an operator gains information about external corrosion, it must enhance its external corrosion management program, as required under subpart I of this part, with respect to a covered segment to

prevent and minimize the consequences of a release due to external corrosion. At a minimum, as part of this enhancement, operators must—

(1) Control electrical interference currents that can adversely affect cathodic protection as follows:

(i) As frequently as needed (such as when new or uprated high voltage alternating current power lines greater than or equal to 69 kVA or electrical substations are co-located near the pipeline), but not to exceed every seven years, perform the following:

(A) Conduct an interference survey (at times when voltages are at the highest values for a time period of at least 24-hours) to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;

(B) Analyze the results of the survey to identify locations where interference currents are greater than or equal to 20 Amps per meter squared; and

(C) Take any remedial action needed within six months after completing the survey to protect the pipeline segment from deleterious current. Remedial action means the implementation of measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. Any location with interference currents greater than 50 Amps per meter squared must be remediated. If any AC interference between 20 and 50 Amps per meter squared is not remediated, the operator must provide and document an engineering justification.

(2) Confirm the adequacy of external corrosion control through indirect assessment as follows:

(i) Periodically (as frequently as needed but at intervals not to exceed seven years) assess the adequacy of the cathodic protection through an indirect method such as close-interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG).

(ii) Remediate any damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP0502–2008 (incorporated by reference, see § 192.7).

(iii) Integrate the results of the indirect assessment required under paragraph (g)(2)(i) of this section with the results of the most recent integrity assessment required by this subpart and promptly take any needed remedial actions no later than 6 months after assessment finding.

(iv) Perform periodic assessments as follows:

(A) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with integrity assessments under sections §§ 192.921 and 192.937 of this subpart.

(B) Locate pipe-to-soil test stations at half-mile intervals within each covered segment, ensuring at least one station is within each high consequence area, if practicable.

(C) Integrate the results with those of the baseline and periodic assessments for integrity done under sections §§ 192.921 and 192.937 of this subpart.

(3) Control external corrosion through cathodic protection as follows:

(i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete assessment and remedial action, as required in § 192.465(f), within 6 months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service and demonstrate that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and

(ii) Remediate insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline in accordance with paragraph (g)(3)(i) of this section, including use of indirect assessments or direct examination of the coating in areas of low CP readings unless the reason for the failed reading is determined to be a short to an adjacent foreign structure, rectifier connection or power input problem that can be remediated and restoration of adequate cathodic protection can be verified. The operator must confirm restoration of adequate corrosion control by a close interval survey on both sides of the affected test stations to the adjacent test stations.

■ 46. In § 192.937, paragraphs (b) and (c) are revised to read as follows:

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

* * * * *

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917, which incorporates an analysis of updated pipeline design, construction, operation, maintenance, and integrity information. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in § 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933). The evaluation must identify the threats specific to each covered segment, including interacting threats and the risk represented by these threats, and identify additional preventive and mitigative measures (§ 192.935) to avert or reduce risks.

(c) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917). An operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(1) Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. 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. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing anomalies.

(2) Pressure test conducted in accordance with subpart J of this part.

An operator must use the test pressures specified in table 3 of section 5 of ASME/ANSI B31.8S to justify an extended reassessment interval in accordance with § 192.939. The use of pressure testing is appropriate for time dependent threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms and for manufacturing and related defect threats, including defective pipe and pipe seams.

(3) ''Spike'' hydrostatic pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for threats such as stress corrosion cracking, selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects.

(4) Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI). An operator must explicitly consider uncertainties in in situ direct examination results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, and usage unity chart plots or equivalent for determining uncertainties and verifying performance on the type defects being evaluated) in identifying and characterizing anomalies.

(5) Guided Wave Ultrasonic Testing (GWUT) conducted as described in Appendix F;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (c)(1) through (5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in § 192.925, 192.927, or 192.929;

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with § 192.949 and receive a ''no objection letter'' from the Associate Administrator of Pipeline Safety. An operator must also notify the appropriate State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(8) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with § 192.931.

■ 47. In § 192.939, the introductory text of paragraph (a) is revised to read as follows:

§ 192.939 What are the required reassessment intervals?

* * * * *

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven calendar years. Operators may request a six month extension of the seven-calendar year reassessment interval if the operator submits written notice to OPS, in accordance with § 192.949, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than seven calendar years, the operator must, within the seven-calendar year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with § 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

* * * * *

■ 48. In § 192.941, paragraphs (b)(1) and the introductory text to (b)(2) are revised to read as follows:

§ 192.941 What is a low stress reassessment?

* * * * *

(b) * * *

(1) *Cathodically protected pipe.* To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an indirect assessment (*i.e.* indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) at least every seven years on the covered segment. An operator must use the results of each indirect assessment as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where indirect assessments are impractical.* If an indirect assessment is impractical on the covered segment an operator must—

* * * * *

■ 49. Appendix A to part 192 is revised to read as follows:

Appendix A to Part 192—Records Retention Schedule for Transmission Pipelines

Appendix A summarizes the part 192 records retention requirements. As required by § 192.13(e), records must be readily retrievable and must be reliable, traceable, verifiable, and complete.

Code section	Section title	Summary of records requirement (**Note:** referenced code section specifies requirements. This summary provided for convenience only.)	Retention time
Subpart A—General			
§ 192.5(d)	Class locations	Records that demonstrate how an operator determined class locations and the actual class locations.	Life of pipeline.
§ 192.13(e)	What general requirements apply to pipelines regulated under this part?.	Records that demonstrate compliance with this part. At a minimum, operators must prepare and maintain the records specified in appendix A to part 192.	As specified in this appendix.

Code section	Section title	Summary of records requirement (**Note:** referenced code section specifies requirements. This summary provided for convenience only.)	Retention time
§ 192.14(b)	Conversion to service subject to this part.	Records of investigations, tests, repairs, replacements, and alterations made under the requirements of § 192.14(a).	Life of pipeline.
§ 192.16(d)	Customer notification	Records of a copy of the notice currently in use and evidence that notices have been sent to customers.	3 years.
Subpart B—Materials			
§ 192.67	Records: Materials and pipe	Records for steel pipe manufacturing tests, inspections, and attributes.	Life of pipeline.
Subpart C—Pipe Design			
§ 192.112	Additional design requirements for steel pipe using alternative maximum allowable operating pressure.	Records for alternative MAOP demonstrating compliance with this section.	Life of pipeline.
§ 192.127	Records: Pipe Design for External Loads and Internal Pressures.	Design records for external loads and internal pressure.	Life of pipeline.
Subpart D—Design of Pipeline Components			
§ 192.144	Qualifying metallic components	Records indicating manufacturer and pressure ratings of metallic components.	Life of pipeline.
§ 192.150	Passage of internal inspection devices	Records of each new transmission line replacement of pipe, valves, fittings, or other line component showing that the replacement is constructed to accommodate internal inspection devices as required by § 192.150.	Life of pipeline.
§ 192.153	Components fabricated by welding	Records of strength tests	Life of pipeline.
§ 192.205	Records: Pipeline components	Records documenting the manufacturing standard, tests, and pressure rating to which valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, tap connections, and other components were manufactured and tested in accordance with this subpart.	Life of pipeline.
Subpart E—Welding of Steel in Pipelines			
§ 192.225(b)	Welding procedures	Records of welding procedures, including results of qualifying procedure tests.	Life of pipeline.
§ 192.227(c)	Qualification of welders and welding operators.	Records demonstrating welder qualification	Life of pipeline.
§ 192.243(f)	Nondestructive testing	Records showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.	Life of pipeline.
Subpart F—Joining of Materials Other Than by Welding			
§ 192.283	Plastic pipe: Qualifying joining procedures.	Records of joining procedures, including results of qualifying procedure tests.	Life of pipeline.
§ 192.285(e)	Plastic pipe: Qualifying persons to make joints.	Records demonstrating plastic pipe joining qualifications.	Life of pipeline.
Subpart G—General Construction Requirements for Transmission Lines and Mains			
§ 192.303	Compliance with specifications or standards.	Records of written specifications or standards that apply to each transmission line or main.	Life of pipeline.
§ 192.305	Inspection: General	Transmission line or main inspections	Life of pipeline.
§ 192.307	Inspection of materials	Pipe and component materials inspections	Life of pipeline.
§ 192.319(d)	Installation of pipe in a ditch	Records documenting the coating assessment findings and repairs.	Life of pipeline.
§ 192.328	Additional construction requirements for steel pipe using alternative maximum allowable operating pressure.	Records for alternative MAOP demonstrating compliance with this section including: quality assurance, girth weld non-destructive examinations, depth of cover, initial strength testing (pressure tests and root cause analysis of failed pipe), and impacts of interference currents.	Life of pipeline.

Code section	Section title	Summary of records requirement (**Note:** referenced code section specifies requirements. This summary provided for convenience only.)	Retention time
Subpart H—Customer Meters, Service Regulators, and Service Lines			
§ 192.383	Excess flow valve installation	Number of excess flow valves installed, as reported as part of annual report.	Life of pipeline.
Subpart I—Requirements for Corrosion Control			
§ 192.452(a)	How does this subpart apply to converted pipelines and regulated onshore gathering lines?.	Records demonstrating compliance by the applicable deadlines.	Life of pipeline.
§ 192.459	Exposed buried pipe inspection	Records of examinations for evidence of external corrosion whenever any portion of a buried pipeline is exposed.	Life of pipeline.
§ 192.461	External corrosion control: Protective coating.	Records of protective coating type, coating installation and procedures, surveys, and remediation of coating defects.	Life of pipeline.
§ 192.465(a)	External corrosion control: Monitoring	Records of pipe to soil measurements	Life of pipeline.
§ 192.465(b)	External corrosion control: Monitoring—rectifiers.	Records of rectifier inspections	5 years.
§ 192.465(c)	External corrosion control: Monitoring—stray current/interference mitigation and critical interference bonds.	Records of inspections of each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection.	5 years.
§ 192.465(e)	External corrosion control: Monitoring—active corrosion zones.	Records of re-evaluation of cathodically unprotected pipelines.	Life of pipeline.
§ 192.467(d)	External corrosion control: Electrical isolation.	Records of inspection and electrical tests made to assure that electrical isolation is adequate.	Life of pipeline.
§ 192.473	External corrosion control: Interference currents.	Records of surveys, analysis, and remediation of interference currents.	Life of pipeline.
§ 192.475	Internal pipe inspection	Records demonstrating whenever any pipe is removed from a pipeline for any reason, the internal surface was inspected for evidence of corrosion.	Life of pipeline.
§ 192.476(d)	Internal corrosion control: Design and construction of transmission line.	Records demonstrating compliance with this section	Life of pipeline.
§ 192.477	Coupons or other means for monitoring internal corrosion.	Records demonstrating the effectiveness of each coupon or other means of monitoring procedures used to minimize internal corrosion.	Life of pipeline.
§ 192.478	Internal corrosion control: Onshore transmission monitoring and mitigation.	Records demonstrating compliance with this section for internal monitoring and mitigation program.	Life of pipeline.
§ 192.478(b)(3)	Gas and Liquid Samples	Records showing evaluation twice each calendar year of gas stream and liquid quality samples.	Life of pipeline.
§ 192.481(a)	Atmospheric corrosion control: Monitoring.	Records of inspection of each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion.	5 years.
§ 192.485(c)	Remedial measures: Transmission lines.	Pipe and material properties used in remaining strength calculations and remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records.	Life of pipeline.
§ 192.491(a) and (b)	Corrosion control records	Records or maps showing the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system.	Life of pipeline.
§ 192.491(c)	Corrosion control records	Records of each test, survey, or inspection required by subpart I in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist.	5 years.
		Records related to §§ 192.465(a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.	Life of pipeline.
Subpart J—Test Requirements			
§ 192.517(a)	Records	Records of each test performed under §§ 192.505, 192.506, and 192.507.	Life of pipeline.
§ 192.517(b)	Records	Records of each test required by §§ 192.509, 192.511, and 192.513.	5 years.

Code section	Section title	Summary of records requirement (**Note:** referenced code section specifies requirements. This summary provided for convenience only.)	Retention time
		Subpart K—Uprating	
§ 192.553(b)	General requirements	Records of each investigation required by subpart K, of all work performed, and of each pressure test conducted, in connection with uprating of a segment of pipeline.	Life of pipeline.
		Subpart L—Operations	
§ 192.603(b)	General provisions	Records necessary to administer the procedures established under § 192.605 for operations, maintenance, and emergencies including class location and changes in §§ 192.5, 192.609, and 192.611.	Life of pipeline.
§ 192.605	Procedural manual for operations, maintenance, and emergencies.	Records for O&M Manual—review and update once per calendar year, not to exceed 15 months.	5 years.
§ 192.605	Procedural manual for operations, maintenance, and emergencies.	Records for Emergency Plan—review and update once per calendar year, not to exceed 15 months.	5 years.
§ 192.605	Procedural manual for operations, maintenance, and emergencies.	Records for Operator Qualification Plan—review and update once per calendar year, not to exceed 15 months.	5 years.
§ 192.605(b)(12)	Procedural manual for operations, maintenance, and emergencies.	Records for Control Room Management (CRM)—review and update once per calendar year, not to exceed 15 months.	5 years.
§ 192.605(c)	Procedural manual for operations, maintenance, and emergencies.	For gas transmission operators, a record of the abnormal operations.	Life of pipeline.
§ 192.607(c)	Verification of Pipeline Material: Onshore steel transmission pipelines.	Traceable, verifiable, and complete records that demonstrate and authenticate data and information regarding the properties outlined in § 192.607(c)(1) through (4).	Life of pipeline.
§ 192.609	Change in class location: Required study.	Records for class location studies required by this section.	Life of pipeline.
§ 192.611	Change in class location: Confirmation or revision of maximum allowable operating pressure.	Records for revisions of maximum allowable operating pressure due to class location changes to confirm to § 192.611.	Life of pipeline.
§ 192.612	Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.	Records of Underwater inspection in Gulf of Mexico—periodic, as indicated in operators O&M Manual.	5 years.
§ 192.613(a)	Continuing surveillance	Records of continuing surveillance findings	5 years.
§ 192.613(b)	Continuing surveillance	Records of remedial actions	Life of pipeline.
§ 192.613(c)(1)	Continuing surveillance	Records of inspections performed following extreme events.	5 years.
§ 192.613(c)(3)	Continuing surveillance	Records of remedial actions	Life of pipeline.
§ 192.614	Damage prevention program	Damage Prevention/One Call records	5 years (or as indicated by state one call, whichever is longer).
§ 192.614	Damage prevention program	Records of Damage Prevention meetings with Emergency Responder/Public Officials.	5 years.
§ 192.615	Emergency plans	Records of training	5 years.
§ 192.615	Emergency plans	Records of each review that procedures were effectively followed after each emergency.	5 years.
§ 192.616	Public awareness	Records showing Public Education Activities	5 years.
§ 192.617	Investigation of failures	Procedures for analyzing accidents and failures as described in § 192.617 to determine the causes of the failure and minimizing the possibility of a recurrence. Records of accident/failure reports.	Life of pipeline.
§ 192.619	Maximum allowable operating pressure: Steel or plastic pipelines.	Traceable, verifiable, and complete records that demonstrate and authenticate data and information regarding the maximum allowable operating pressures outlined in § 192.619(a) through (d).	Life of pipeline.
§ 192.620(c)(7)	Alternative maximum allowable operating pressure for certain steel pipelines.	Records demonstrating compliance with paragraphs § 192.620(b), (c)(6), and (d).	Life of pipeline.
§ 192.624(f)	Maximum allowable operating pressure verification: Onshore steel transmission pipelines.	Reliable, traceable, verifiable, and complete records of the investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions made under the requirements of § 192.624.	Life of pipeline.
§ 192.625	Odorization of gas	Records of Odorometer Readings—periodic, as indicated in operators O&M Manual.	5 years.

Code section	Section title	Summary of records requirement (**Note:** referenced code section specifies requirements. This summary provided for convenience only.)	Retention time
§ 192.631(a)	Control room management	Records of control room management procedures that implement the requirements of this section.	Life of pipeline.
§ 192.631(j)	Control room management	(1) Records that demonstrate compliance with the requirements of this section; and. (2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of a pipeline facility.	1 year, or the last 2 periodic tests or validations, whichever is longer.
Subpart M—Maintenance			
§ 192.703(c)	General	Records of hazardous and non-hazardous leaks	Life of pipeline.
§ 192.705	Transmission lines: Patrolling	Records of periodic right-of-way patrols—frequency dependent on class location.	5 years.
§ 192.706	Transmission lines: Leakage surveys	Records of periodic leakage surveys—frequency dependent on class location.	5 years.
§ 192.709(a)	Transmission lines: Record keeping	Records for the date, location, and description of each repair made to pipe (including pipe-to-pipe connections).	Life of pipeline.
§ 192.709(b) and (c)	Transmission lines: Record keeping	(b) Records of the date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. (c) A record of each patrol, survey, inspection, test, and repair required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.*	5 years.*
§ 192.710	Pipeline assessments	Records of pipeline assessments in class 3 or class 4 locations and moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., ''smart pigs'').	Life of pipeline.
§ 192.713(c)	Transmission lines: Permanent field repair of imperfections and damages.	Records of each repair made to transmission lines must be documented.	Life of pipeline.
§ 192.713(d)	Transmission lines: Permanent field repair of imperfections and damages.	Repair and remediation schedules, pressure reductions and remaining strength calculations must be documented.	Life of pipeline.
§ 192.731	Compressor stations: Inspection and testing of relief devices.	Records of inspections and tests of pressure relieving and other remote control shutdown devices.	5 years.
§ 192.736	Compressor stations: Gas detection	Records of inspections and tests of gas detection systems—periodic, as indicated in operators O&M Manual.	5 years.
§ 192.739	Pressure limiting and regulating stations: Inspection and testing.	Records of inspections and tests of pressure relief devices and pressure regulating stations and equipment.	5 years.
§ 192.743	Pressure limiting and regulating stations: Capacity of relief devices.	Records of capacity calculations or verifications for pressure relief devices (except rupture discs).	5 years.
§ 192.745	Valve maintenance: Transmission lines	Records of inspections of emergency valves	5 years.
§ 192.749	Vault maintenance	Records of inspections of vaults containing pressure regulating or pressure limiting equipment.	5 years.
Subpart N—Qualification of Pipeline Personnel			
§ 192.807	Operator qualification recordkeeping	Records that demonstrate compliance with subpart N of this part Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task.** Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years..	5 years.**
Subpart O—Gas Transmission Integrity Management			
§ 192.947	Integrity management	Records that demonstrate compliance with all of the requirements of subpart O of this part.	Life of pipeline.

■ 50. Appendix D to part 192 is revised to read as follows:

Appendix D to Part 192—Criteria for Cathodic Protection and Determination of Measurements

I. *Criteria for cathodic protection—*

A. *Steel, cast iron, and ductile iron structures.*

(1) A negative (cathodic) voltage across the structure electrolyte boundary of at least 0.85 volt, with reference to a saturated copper-copper sulfate reference electrode, often referred to as a half cell. Determination of this voltage must be made in accordance with sections II and IV of this appendix.

(2) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

B. *Aluminum structures.*

(1) Except as provided in paragraphs B(2) and (3) of this section, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(2) Notwithstanding the minimum criteria in paragraph B(1) of this section, if aluminum is cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate reference electrode, in accordance with section II of this appendix, the aluminum may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(3) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures.* A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. *Metals of different anodic potentials.* A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs B(2) and (3) of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement.* Structure-to-electrolyte potential measurements must be made utilizing measurement techniques that will minimize voltage (IR) drops other than those across the structure electrolyte boundary. All voltage (IR) drops other than those across the structure electrolyte boundary will be differentiated, such that the resulting measurement accurately reflects the structure-to-electrolyte potential.

III. *Determination of polarization voltage shift.* The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs often referred to as an instant off potential. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(2), B(1), and C of section I of this appendix.

IV. *Reference electrodes (half cells).*

A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate reference electrode contacting the electrolyte.

B. Other standard reference electrodes may be substituted for the saturated copper-copper sulfate electrode. Two commonly used reference electrodes are listed below along with their voltage equivalent to −0.85 volt as referred to a saturated copper-copper sulfate reference electrode:

(1) Saturated KCL calomel half cell: −0.78 volt.

(2) Silver-silver chloride reference electrode used in sea water: −0.80 volt.

C. In addition to the standard reference electrode, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate reference electrode if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate reference electrode is established.

■ 51. In appendix E, Tables E.II.1 and E.II.3 are revised to read as follows:

Appendix E to Part 192—Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule

* * * * *

II. Guidance on Assessment Methods and Additional Preventive and Mitigative Measures for Transmission Pipelines

* * * * *

TABLE E.II.1—PREVENTIVE AND MITIGATIVE MEASURES FOR TRANSMISSION PIPELINES OPERATING BELOW 30% SMYS NOT IN AN HCA BUT IN A CLASS 3 OR CLASS 4 LOCATION

(Column 1) Threat	Existing part 192 requirements		(Column 4) Additional (to part 192 requirements) preventive and mitigative measures
	(Column 2) Primary	(Column 3) Secondary	
External Corrosion	455—(Gen. Post 1971), 457—(Gen. Pre—1971).	603—(Gen Operation)	For Cathodically Protected Transmission Pipeline:
	459—(Examination), 461—(Ext. coating).	613—(Surveillance)	• Perform semi-annual leak surveys.
	463—(CP), 465—(Monitoring).		For Unprotected Transmission Pipelines or for Cathodically Protected Pipe where indirect assessments (*i.e.,* indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) are impractical:
	467—(Elect isolation), 469—Test stations).		
	471—(Test leads), 473—(Interference).		
	479—(Atmospheric), 481—(Atmospheric).		
	485—(Remedial), 705—(Patrol).		
	706— (Leak survey), 711—(Repair—gen.).		
	717—(Repair—perm.)		• Perform quarterly leak surveys.
Internal Corrosion	475—(Gen IC), 477—(IC monitoring).	53(a)—(Materials)	Perform semi-annual leak surveys.

TABLE E.II.1—PREVENTIVE AND MITIGATIVE MEASURES FOR TRANSMISSION PIPELINES OPERATING BELOW 30% SMYS NOT IN AN HCA BUT IN A CLASS 3 OR CLASS 4 LOCATION—Continued

(Column 1) Threat	Existing part 192 requirements		(Column 4) Additional (to part 192 requirements) preventive and mitigative measures
	(Column 2) Primary	(Column 3) Secondary	
3rd Party Damage	485—(Remedial), 705—(Patrol). 706—(Leak survey), 711 (Repair—gen.). 717—(Repair—perm.). 103—(Gen. Design), 111—(Design factor). 317—(Hazard prot), 327—(Cover). 614—(Dam. Prevent), 616—(Public education). 705—(Patrol), 707—(Line markers). 711—(Repair—gen.), 717—(Repair—perm.).	603—(Gen Oper'n). 613—(Surveillance). 615—(Emerg. Plan)	• Participation in state one-call system. • Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work. AND • Either monitoring of excavations near operator's transmission pipelines in class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.

* * * * *

TABLE E.II.3—PREVENTIVE AND MITIGATIVE MEASURES ADDRESSING TIME DEPENDENT AND INDEPENDENT THREATS FOR TRANSMISSION PIPELINES THAT OPERATE BELOW 30% SMYS, IN HCAS

Threat	Existing part 192 requirements		Additional (to part 192 requirements) preventive and mitigative measures
	Primary	Secondary	
External Corrosion	455—(Gen. Post 1971) 457—(Gen. Pre-1971) ... 459—(Examination). 461—(Ext. coating). 463—(CP). 465—(Monitoring) ..... 467—(Elect isolation) .... 469—(Test stations). 471—(Test leads) ..... 473—(Interference). 479—(Atmospheric) ..... 481—(Atmospheric) ..... 485—(Remedial). 705—(Patrol). 706—(Leak survey). 711—(Repair—gen.). 717—(Repair—perm.).	 603—(Gen. Operation). 613—(Surveillance).	*For Cathodically Protected Transmission Pipelines* • Perform an indirect assessment (i.e. indirect examination tool/method such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) at least every 7 years. Results are to be utilized as part of an overall evaluation of the CP system and corrosion threat for the covered segment. Evaluation shall include consideration of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. *For Unprotected Transmission. Pipelines or for Cathodically Protected Pipe where Indirect Assessments are Impracticable* • Conduct quarterly leak surveys AND • Every 1½ years, determine areas of active corrosion by evaluation of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
Internal Corrosion	475—(Gen. IC) ..... 477—(IC monitoring) ..... 485—(Remedial) ..... 705—(Patrol) ..... 706—(Leak survey) ..... 711—(Repair—gen.).	 53(a)—(Materials) ..... 603—(Gen. Oper.). 613—(Surveil.).	• Obtain and review gas analysis data each calendar year for corrosive agents from transmission pipelines in HCA, • Periodic testing of fluid removed from pipelines. Specifically, once each year from each storage field that may affect transmission pipelines in HCA, AND • At least every 7 years, integrate data obtained with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records.

TABLE E.II.3—PREVENTIVE AND MITIGATIVE MEASURES ADDRESSING TIME DEPENDENT AND INDEPENDENT THREATS FOR TRANSMISSION PIPELINES THAT OPERATE BELOW 30% SMYS, IN HCAS—Continued

Threat	Existing part 192 requirements		Additional (to part 192 requirements) preventive and mitigative measures
	Primary	Secondary	
3rd Party Damage	717—(Repair—perm.). 103—(Gen. Design) ..... 111—(Design factor) ..... 317—(Hazard prot.) ..... 327—(Cover). 614—(Dam. Prevent). 616—(Public educat.). 705—(Patrol). 707—(Line markers). 711—(Repair—gen.). 717—(Repair—perm.).	615— (Emerg. Plan)	• Participation in state one-call system, • Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND • Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in HCAs or class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.

■ 52. Appendix F to part 192 is added to read as follows:

Appendix F to Part 192—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

This appendix defines criteria which must be properly implemented for use of Guided Wave Ultrasonic Testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered ''other technology'' as described by §§ 192.710(c)(7), 192.921(a)(7), and 192.937(c)(7), for which OPS must be notified 180 days prior to use in accordance with § 192.921(a)(7) or 192.937(c)(7). GWUT in the ''Go-No Go'' mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of 5% of cross sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested or replaced prior to completing the integrity assessment on the cased carrier pipe.

I. *Equipment and software: Generation.* The equipment and the computer software used are critical to the success of the inspection. Guided Ultrasonics LTD (GUL) Wavemaker G3 or G4 with software version 3 or higher, or equipment and software with equivalent capabilities and sensitivities, must be used.

II. *Inspection range.* The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.

III. *Complete pipe inspection.* To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

IV. *Sensitivity.*

A. The detection sensitivity threshold determines the ability to identify a cross sectional change. The maximum threshold sensitivity cannot be greater than 5% of the cross sectional area (CSA).

B. The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented.

C. All defect indications in the ''Go-No Go'' mode above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

V. *Wave frequency.* Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

VI. *Signal or wave type: Torsional and longitudinal.* Both torsional and longitudinal waves must be used and use must be documented.

VII. *Distance amplitude correction (DAC) curve and weld calibration.*

A. The Distance Amplitude Correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection.

B. DAC curves provide a means for evaluating the cross sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

VIII. *Dead zone.* The dead zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

IX. *Near field effects.* The near field is the region beyond the dead zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

X. *Coating type.*

A. Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance.

B. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For

example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the cased pipe, then another type of assessment method must be utilized.

XI. *End seal.* Operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.

XII. *Weld calibration to set DAC curve.* Accessible welds, along or outside the pipe segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipe segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by sound engineering analysis and evaluation.

XIII. *Validation of operator training.*

A. There is no industry standard for qualifying GWUT service providers. Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT equipment operators which includes training for:

(1) Equipment operation;

(2) Field data collection; and

(3) Data interpretation on cased and buried pipe.

B. Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment.

C. A Senior level GWUT equipment operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A senior level GWUT equipment operator must have additional training and experience, including but not limited to training specific to cased and buried pipe, with a quality control program which conforms to section 12 of ASME B31.8S.

D. Training and experience minimums for senior level GWUT equipment operators:

(1) Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe

(2) Training, qualification and experience in testing procedures and frequency determination

(3) Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)

(4) Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XIV. *Equipment: Traceable from vendor to inspection company.* The operator must maintain documentation of the version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., in the report.

XV. *Calibration onsite.* The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated. If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.

XVI. *Use on shorted casings (direct or electrolytic).* GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (see § 192.605) to address the effect of shorted casings on the GWUT signal. The equipment operator must clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures. All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures.

XVII. *Direct examination of all indications above the detection sensitivity threshold.*

The use of GWUT in the ''Go-No Go'' mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe. If this cannot be accomplished then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

XVIII. *Timing of direct examination of all indications above the detection sensitivity threshold.* Operators must either replace or conduct direct examinations of all indications identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

Required response to GWUT indications

GWUT Criterion	Operating pressure less than or equal to 30% SMYS	Operating pressure over 30 and less than or equal to 50% SMYS	Operating pressure over 50% SMYS
Over the detection sensitivity threshold (maximum of 5% CSA).	Replace or direct examination within 12 months, and instrumented leak survey once every 30 calendar days.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and maintain MAOP below the operating pressure at time of discovery.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and reduce MAOP to 80% of operating pressure at time of discovery.

Issued in Washington, DC, on March 17, 2016, under authority delegated in 49 CFR part 1.97(a).

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

[FR Doc. 2016–06382 Filed 4–7–16; 8:45 am]

BILLING CODE 4910–60–P