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DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA-2011-0023; Amdt. Nos. 191-26; 192-125]

RIN 2137-AE72

Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments

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

ACTION: Final rule.

SUMMARY: PHMSA is revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission pipelines. This final rule addresses congressional mandates, National Transportation Safety Board recommendations, and responds to public input. The amendments in this final rule address integrity management requirements and other requirements, and they focus on the actions an operator must take to reconfirm the maximum allowable operating pressure of previously untested natural gas transmission pipelines and pipelines lacking certain material or operational records, the periodic assessment of pipelines in populated areas not designated as "high consequence areas," the reporting of exceedances of maximum allowable operating pressure, the consideration of seismicity as a risk factor in integrity management, safety features on in-line inspection launchers and receivers, a 6-month grace period for 7-calendar-year integrity management reassessment intervals, and related recordkeeping provisions.

DATES: The effective date of this final rule is **July 1, 2020**. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of

July 1, 2020. The incorporation by reference of ASME/ANSI B31.8S was approved by the Director of the Federal Register as of January 14, 2004.

FOR FURTHER INFORMATION CONTACT: Technical questions: Steve Nanney, Project Manager, by telephone at 713-272-2855. General information: Robert Jagger, Senior Transportation Specialist, by telephone at 202-366-4361.

SUPPLEMENTARY INFORMATION:

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 continue to occur on gas pipeline systems resulting in serious risks to life and property. One such incident occurred in San Bruno, CA, on September 9, 2010, killing 8 people, injuring 51, destroying 38 homes, and damaging another 70 homes (PG&E incident). In its investigation of the incident, the National Transportation Safety Board (NTSB) found among several causal factors that the operator, Pacific Gas and Electric (PG&E), had an inadequate integrity management (IM) program that failed to detect and repair or remove the defective pipe section. PG&E was basing its IM program on incomplete and inaccurate pipeline information, which led to, among other things, faulty risk assessments, improper assessment method selection, and internal assessments of the program that were superficial and resulted in no meaningful improvement in the integrity of the pipeline system nor the IM program itself.

The PG&E incident underscored the need for PHMSA to extend IM requirements and address other issues related to pipeline system integrity. In response, PHMSA published an ANPRM seeking comment on whether IM and other requirements should be strengthened or expanded, and other related issues, on August 25, 2011 (76 FR 53086).

The NTSB adopted its report on the PG&E incident on August 30, 2011, and issued several safety recommendations to PHMSA and other entities. Several of these NTSB recommendations related directly to the topics addressed in the 2011 ANPRM and are addressed in this final rule. Also, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act) was enacted on January 3, 2012. Several of the 2011 Pipeline Safety Act's statutory requirements related directly to the topics addressed in the 2011 ANPRM and are a focus of this rulemaking.

Another incident that influenced this rulemaking was the rupture of a gas transmission pipe operated by Columbia Gas near Sissonville, WV, on December 11, 2012. The escaping gas ignited, and fire damage extended nearly 1,100 feet along the pipeline right-of-way and covered an area roughly 820 feet wide. While there were no fatalities or serious injuries, three houses were destroyed by the fire, and several other houses were damaged. The ruptured pipe was one of three in the area that cross Interstate 77, and the incident closed the highway in both directions for 19 hours until a section of thermally damaged road surface approximately 800 feet long could be replaced. Following this incident, the NTSB finalized an accident report on February 19, 2014, issuing recommendations to PHMSA to include principal arterial roadways, including interstates, other freeways and expressways, and other principal arterial roadways as defined by the Federal Highway Administration, to the list of "identified sites" that establish a high consequence area (HCA) for the purposes of an operator's IM program.

On April 8, 2016, PHMSA published an NPRM to seek public comments on proposed changes to the gas transmission pipeline safety regulations (81 FR 20722). A summary of those proposed changes, and PHMSA's response to stakeholder feedback on the individual provisions, is provided below in section IV of this document (Analysis of Comments and PHMSA Response).

The purpose of this final rule is to increase the level of safety associated with the transportation of gas. PHMSA is finalizing requirements that address the causes of several recent incidents, including the PG&E incident, by clarifying and enhancing existing requirements. PHMSA is also addressing certain statutory mandates of the 2011 Pipeline Safety Act and NTSB recommendations. While the NPRM addressed 16 major topic areas, PHMSA believes the most efficient way to manage the proposals in the NPRM is to divide them into three rulemaking actions. PHMSA is finalizing the provisions in this final rule as a first step. PHMSA anticipates completing a second rulemaking to address the topics in the NPRM regarding repair criteria in HCAs and the creation of new repair criteria for non-HCAs, requirements for inspecting pipelines following extreme events, updates to pipeline corrosion control requirements, codification of a management of change process, clarification of certain other IM requirements, and strengthening IM assessment requirements.[1] A third rulemaking is expected to address requirements related to gas gathering lines that were proposed in the NPRM.[2]

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

Several of the amendments made in this rule are related to congressional legislation from the 2011 Pipeline Safety Act. The Act provides a 6-month grace period, with written notice, for the completion of periodic integrity management reassessments that otherwise would be completed no later than every 7 calendar years.[3] Another requirement is that operators explicitly

[1] RIN 2137-AF39.
[2] RIN 2137-AF38.
[3] 2011 Pipeline Safety Act § 5(e).

consider and account for seismicity in identifying and evaluating potential threats.[4] The Act also requires operators to report exceedances of the maximum allowable operating pressure (MAOP) of gas transmission pipelines.[5,6] PHMSA is incorporating these changes into the PSR at 49 CFR parts 190-199 in this final rule.

This rule also requires operators of certain onshore steel gas transmission pipeline segments to reconfirm the MAOP of those segments and gather any necessary material property records they might need to do so, where the records needed to substantiate the MAOP are not traceable, verifiable, and complete. This includes previously untested pipelines, which are commonly referred to as "grandfathered" pipelines, operating at or above 30 percent of specified minimum yield strength (SMYS). Records to confirm MAOP include pressure test records or material property records (mechanical properties) that verify the MAOP is appropriate for the class location.[7] Operators with missing records can choose one of six methods to reconfirm their MAOP and must keep the record that is generated by this exercise for the life of the pipeline. PHMSA has also created an opportunistic method by which operators with insufficient material property records can obtain such records. These physical material property and attribute records include the pipeline segment's diameter, wall thickness, seam type, grade (the minimum yield strength and ultimate tensile strength of the pipe), and Charpy V-notch toughness values (full-

[4] 2011 Pipeline Safety Act § 29.
[5] 2011 Pipeline Safety Act § 23.
[6] MAOP means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.
[7] PHMSA uses class locations throughout part 192 to provide safety margins and standards commensurate with the potential consequence of a pipeline failure based on the surrounding population. Class locations are defined at § 192.5. A Class 1 location is an offshore area or a class location unit with 10 or fewer buildings intended for human occupancy. A Class 2 location is a class location unit with more than 10 but fewer than 46 buildings intended for human occupancy. A Class 3 location is a class location unit with 46 or more buildings intended for human occupancy, and a Class 4 location is where buildings with 4-or-more stories above ground are prevalent.

size specimen and based on the lowest operational temperatures),[8] if applicable or required. PHMSA considers "insufficient" material property records to be those records where the pipeline's physical material properties and attributes are not documented in traceable, verifiable, and complete records.

PHMSA is requiring operators to perform integrity assessments on certain pipelines outside of HCAs, whereas prior to this rule's publication, integrity assessments were only required for pipelines in HCAs. Pipelines in Class 3 locations, Class 4 locations, and in the newly defined "moderate consequence areas" (MCA)[9] must be assessed initially within 14 years of this rule's publication date and then must be reassessed at least once every 10 years thereafter. These assessments will provide important information to operators about the conditions of their pipelines, including the existence of internal and external corrosion and other anomalies, and will provide an elevated level of safety for the populations in MCAs while continuing to allow operators to prioritize the safety of HCAs. This action fulfills the section 5 mandate from the 2011 Pipeline Safety Act to expand elements of the IM requirements beyond HCAs where appropriate.

This rule also explicitly requires devices on in-line inspection (ILI), launcher or receiver facilities that can safely relieve pressure in the barrel before inserting or removing ILI tools, and requires the use of a device that can indicate whether the pressure has been relieved in the barrel or can otherwise prevent the barrel from being opened if the pressure is not relieved. PHMSA is

[8] A Charpy V-notch impact test and its values indicate the toughness of a given material at a specified temperature and is used in fracture mechanics analysis.
[9] A MCA is defined in § 191.3 as an onshore area within a potential impact circle, as that term is defined in § 192.903, containing either (1) 5 or more buildings intended for human occupancy or (2) any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1*.

finalizing this requirement in this final rule because it is aware of incidents where operator personnel have been killed or seriously injured due to pressure build-up at these stations.

C. Costs and Benefits

Consistent with Executive Order 12866, PHMSA has prepared an assessment of the benefits and costs of the final rule as well as reasonable alternatives. PHMSA estimates the annual costs of the rule to be approximately $32.7 million, calculated using a 7 percent discount rate. The costs reflect additional integrity assessments, MAOP reconfirmation, and ILI launcher and receiver upgrades.

PHMSA is publishing the Regulatory Impact Analysis (RIA) for this rule in the public docket. The table below provides a summary of the estimated costs for the major provisions in this rulemaking (see the RIA for further detail on these estimates). PHMSA finds that the other final rule requirements will not result in incremental costs. PHMSA did not quantify the cost savings from material properties verification under the final rule compared to existing regulations. PHMSA also elected to not quantify the benefits of this rulemaking and instead discusses them qualitatively. PHMSA estimated total annual costs of the rule of $31.4 million using a 3 percent discount rate, and $32.7 million using a 7 percent discount rate.

Summary of Annualized Costs, 2019 – 2039 ($2017 thousands)		
Provision	***Annualized Cost***	
	3% Discount Rate	***7% Discount Rate***
1. MAOP Reconfirmation & Material Properties Verification	$25,848	$27,899
2. Seismicity	$0.00	$0.00
3. Six-Month Grace Period for Seven Calendar-Year Reassessment Intervals	$0.00	$0.00
4. In-Line Inspection Launcher/Receiver Safety	$27.4	$37.5
5. MAOP Exceedance Reports	$0.00	$0.00
6. Strengthening requirements for assessment methods	$0.00	$0.00
7. Assessments outside HCAs	$5,482	$4,713
8. Related Records Provisions	$0.00	$0.00
Total	**$31,357**	**$32,650**

II. Background

A. Detailed Overview

Introduction

Recent significant 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. Changing spatial patterns of natural gas production and use and an aging pipeline network has made improved documentation and data collection 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 2011 Pipeline Safety Act, calling for an examination 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 IM.[10]

This final rule advances the goals established by Congress in the 2011 Pipeline Safety Act and is consistent with the emerging needs of the natural gas pipeline system. This final rule also advances the important discussion about the need to adapt and expand risk-based safety practices. As some severe pipeline incidents have occurred in areas outside HCAs[11] where the application of IM principles are not required, and as gas pipelines continue to experience failures from causes that IM was intended to address, this conversation is increasingly important.

This final rule strengthens IM requirements, including to ensure operators select the appropriate inspection tool or tools to address the pertinent identified threats to their pipeline segments, and clarifies and expands recordkeeping requirements to ensure operators have and retain the basic physical and operational attributes and characteristics of their pipelines. Further, this final rule establishes requirements to periodically assess pipeline segments in locations outside of HCAs where the surrounding population is expected to potentially be at risk from an incident, which are defined in the rule as MCAs. Even though these pipeline segments are not within currently defined HCAs, they could be located in areas with significant populations. This change facilitates prompt identification and remediation of potentially hazardous defects while still allowing operators to make risk-based decisions on where to allocate their maintenance and repair resources.

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[10] The IM regulations specify how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines in HCAs that could, in the event of a leak or failure, affect high consequence areas in the United States. These areas include certain populated and occupied areas. See § 192.903.

[11] HCAs are defined at § 192.903. There are two methods that can be used to determine and HCA, the specific differences of which we do not address here. Very broadly and regardless of which method used, operators must calculate the potential impact radius for all points along their pipelines and evaluate corresponding impact circles to identify what populations are contained within each circle. Potential impact circles with 20 or more structures intended for human occupancy, or those circles with "identified sites" such as stadiums, playgrounds, office buildings, and religious centers, are defined as HCAs.

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 supply of natural gas.[12] One can consider the Nation's natural gas pipeline infrastructure as three interconnected parts – gathering, transmission, and distribution – 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. This final rule applies only to gas transmission lines and does not address gas gathering or natural gas distribution infrastructure and its associated issues. Currently, there are over 300,000 miles of onshore gas transmission pipelines throughout the U.S.[13]

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

Regulatory History

PHMSA and its State partners regulate and enforce the minimum Federal safety standards

[12] U.S. Department of Energy, "Appendix B: Natural Gas," *Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,* p. NG-28, April 2015.
[13] U.S. DOT Pipeline and Hazardous Materials Safety Administration Data as of 4/26/2018

authorized by statute[14] and codified in the PSR for jurisdictional[15] gas gathering, transmission, and distribution systems.

Federal regulation of gas pipeline safety began in 1968 with the creation of the Office of Pipeline Safety and the passage of the Natural Gas Pipeline Safety Act of 1968 (Public Law 90-481). The Office of Pipeline Safety issued interim minimum Federal safety standards for gas pipeline facilities and the transportation of natural and other gas by pipeline on November 13, 1968, and subsequently codified broad-based gas pipeline regulations on August 19, 1970 (35 FR 13248). The PSR were revised 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 MAOP.

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 reduce damage to 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 uniform standards or requirements.

PHMSA began developing minimum IM regulations for both hazardous liquid and gas transmission pipelines in response to a hazardous liquid accident in Bellingham, WA, in 1999 that killed 3 people and a gas transmission incident in Carlsbad, NM, in 2000 that killed 12. PHMSA finalized IM regulations for gas transmission pipelines in a 2003 final rule.[16] The IM regulations are intended to provide a structure to operators to focus resources on improving

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[14] Title 49, United States Code, Subtitle VIII, Pipelines, Sections 60101, *et. seq.*
[15] Typically, onshore pipelines involved in the "transportation of gas"—see 49 CFR 192.1 and 192.3 for detailed applicability.
[16] "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)." 68 FR 69778; December 15, 2003. Corrected April 6, 2004 (69 FR 18227) and May 26, 2004 (69 FR 29903).

pipeline integrity in the areas where a failure would have the greatest impact on public safety. The IM final rule accelerated the integrity assessment of pipelines in HCAs, improved IM systems, and improved the government's ability to review the adequacy of IM plans.

The IM regulations require that operators conduct comprehensive analyses to identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines in HCAs. Approximately 7 percent of onshore gas transmission pipeline mileage is located in HCAs.[17] PHMSA and State inspectors review operators' 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, sweeping changes in the natural gas industry have caused significant shifts in supply and demand, and the Nation's pipeline network faces increased pressures from these changes as well as from the increased exposure caused by a growing and geographically dispersing population. Also, long-identified pipeline safety issues, some of which IM set out to address, remain problems. A records search following the PG&E incident required by Congress in the 2011 Pipeline Safety Act, showed that some pipeline operators do not have the records they need to substantiate the current MAOP of their pipelines, as required under existing regulations, and lacked other critical information needed to properly assess risks and threats and perform effective IM.[18] PHMSA's inspection experience indicates pipelines continue to be vulnerable to failures stemming from outdated construction methods or

[17] Per PHMSA's 2018 Annual Report, accessed April 9, 2019, 20,435 of the 301,227 miles of gas transmission pipelines are classified as being in HCAs.

[18] An effective IM program requires operators to analyze many data points regarding threats to their systems in addition to pipe attributes, including, but not limited to, construction data (year of installation, pipe bending method, joining method, depth of cover, coating type, pressure test records, etc.), operational data (maximum and minimum operating pressures, leak and failure history, corrosion monitoring, excavation data, corrosion surveys, ILI data, etc.).

materials. Finally, some severe pipeline incidents have occurred in areas outside HCAs where the application of IM principles is not required.

Following the significant pipeline incident in 2010 at San Bruno, CA, in which 8 people died and more than 50 people were injured, Congress charged PHMSA with improving the IM regulations. Additionally, the NTSB and Government Accountability Office (GAO) issued recommendations regarding IM.[19] Comments in response to a 2011 ANPRM on these and related topics 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 outside of HCAs that were not 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 demonstrates a common understanding of the need for this strategy.

Through this final rule, PHMSA is making improvements to IM and is improving the ability of operators to engage in 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 increased production dramatically between 2005 and 2017, from 19.5 trillion cubic feet per year to 28.8 trillion cubic feet per year.[20] This growth was enabled by the production of "unconventional" natural gas supplies using improved technology to extract gas from low permeability shales. The increased use of directional drilling[21] and

[19] More information on the NTSB recommendations being addressed in this rule are discussed in further detail in Section II. D. of this document "National Transportation Safety Board Recommendations." See also, GAO-06-946, Natural Gas Pipeline Safety: Integrity Management Benefits Public Safety, but Consistency of Performance Measures Should be Improved," September 8, 2006.
[20] U.S. Department of Energy, Energy Information Administration, "U.S. Natural Gas marketed Production" https://www.eia.gov/dnav/ng/hist/n9050us2a.htm, accessed 6/28/18.
[21] Directional drilling is the practice of drilling non-vertical wells..

improvements to a long-existing industrial technique—hydraulic fracturing,[22] which began as an experiment in 1947—made the recovery of unconventional natural gas easier and economically viable. This has led to decreased prices and increased use of natural gas, despite a reduction in the production of conventional natural gas of about 14 billion cubic feet per day. Unconventional shale gas production now accounts for nearly 70 percent of overall gas production in the U.S.

Growth in unconventional natural gas production has shifted production away from traditionally gas-rich regions towards inland shale gas regions. To illustrate, in 2004, wells in the Gulf of Mexico's produced 5,066,000 million cubic feet of natural gas per year (Mcf/year), approximately 20 percent of the Nation's natural gas production at the time. By 2016, that number had fallen to 1,220,000 Mcf/year, and approximately 4 percent of natural gas production in the U.S. During that same period, Pennsylvania's share of production grew from 197,217 Mcf/year to 5,463,783 Mcf/year, or approximately 17 percent of total natural gas production in the U.S.[23, 24] An analysis conducted by the Department of Energy's 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,[25] and natural gas production is projected to grow from the 2015 levels of 66.5 Bcf/d to more than 93.5 Bcf/d.[26]

Demand Changes

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[22] The extraction of oil or gas deposits performed by forcing open fissures in subterranean rocks by introducing liquid at high pressures.

[23] U.S. Department of Energy, Energy Information Administration, "Gulf of Mexico – Offshore Natural Gas Withdrawals," https://www.eia.gov/dnav/ng/hist/na1060_r3fmtf_2a.htm, accessed 6/28/18.

[24] U.S. Department of Energy, Energy Information Administration, "Pennsylvania Natural Gas Gross Withdrawals," https://www.eia.gov/dnav/ng/hist/n9010pa2a.htm, accessed 6/28/18.

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

[26] *Id.*, at NG-6

The increase in domestic natural gas production has led to lower average natural gas prices.[27] In 2004, the outlook for natural gas production and demand growth was weak. Monthly average spot prices at Henry Hub[28] were high based on historic comparison of prices, 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.[29] 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.[30]

These low prices have fueled consumption growth and changes in markets and spatial patterns of consumption. A shift towards natural gas-fueled electric power generation, cleaner than other types of fossil fuels, is helping to serve the needs of the Nation's growing population, and increased gas production and lower domestic prices have created opportunities for international export.

Plentiful domestic natural gas supply and comparatively low natural gas prices have changed the economics of electric power markets.[31] To accommodate recent growth and expected future growth in natural gas-fueled power, changes in pipeline infrastructure will be needed, including flow reversals of existing pipelines; additional lines to gas-fired generators; looping of existing networks, where multiple pipelines are laid parallel to one another along a single right-of-way to increase the capacity of a single system; and, potentially, new pipelines as well.

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[27] *Id.*, at NG-11

[28] 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)

[29] Energy Information Administration, Natural Gas Spot and Futures Prices, http://www.eia.gov/dnav/ng/ng_pri_fut_s1_m.htm, retrieved August 2018.

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

[31] *Id.*, at NG-9

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

Despite the significant increase in domestic gas production and the widespread distribution of domestic gas demand, significant flexibility and capacity in the existing transmission system mitigates the level of pipeline expansion and investment required. 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 transmission capacity is needed, the network is being expanded by pipeline investments to enhance network capacity on existing lines rather than increasing coverage through new infrastructure. Additionally, operators have avoided building new pipelines by increasing pipeline diameters or operating pressures. In short, the nation's existing pipeline system is facing the brunt of this dramatic increase in natural gas supply and the shifting energy needs of the country.

In cases where use of the existing pipeline network is high, the next most cost-effective solution is to add capacity to existing lines via compression.[32] Compression requires infrastructure investment in the form of more compressor stations along the pipeline route, but it can be less costly, faster, and simpler for market participants in comparison to building a new pipeline. Adding compression, however, raises pipeline operating pressures and can expose previously hidden defects.

New pipeline projects have been proposed to address pending supply constraints and higher prices. However, gaining public acceptance for natural gas pipeline construction has proved to be a substantial challenge. Pipeline expansion and construction projects often face

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[32] Gas can be reduced in volume by increasing its pressure. Therefore, operators can pack more gas into their lines if they can increase the pressure of the gas being transported.

significant challenges in determining feasible right-of-ways and developing community support for the projects.

Data Challenges

Operators and regulators must have an intimate understanding of the threats to, and operations of, their entire pipeline system. Data gathering and integration are important elements of good IM practices, and while operators have made many strides over the years to collect more and better data, several data gaps still exist. Ironically, the comparatively positive safety record of the Nation's gas transmission pipelines to date makes it harder to quantify some of these gaps. Over the 20-year period of 1998-2017, transmission facilities accounted for 50 fatalities and 179 injuries, or about one-sixth to one-seventh of the total fatalities and injuries caused by natural gas pipeline incidents in the U.S.[33] Given the relatively limited number of significant incidents that occur, it can be challenging to project the possible impact of low-probability but high-consequence events. See the RIA included in the public docket for a more detailed analysis of key types of incidents that may be mitigated by this final rule.

On September 9, 2010, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline owned and operated by PG&E ruptured in a residential area of San Bruno, CA. 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 PG&E incident exposed several problems in the way data on pipeline conditions is collected and managed, showing that the operator had inadequate records regarding the physical and operational characteristics of their pipelines. These records are necessary for the correct

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

setting and validation of MAOP, which is critically important for providing an appropriate margin of safety to the public.

Much of operator data is obtained through the assessments and other safety inspections required by IM regulations. 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 evaluate a pipeline's integrity, operators generally choose between three methods of testing a pipeline: inline inspection (ILI), pressure testing, and direct assessment (DA). In 2017, PHMSA estimates that about two-thirds of gas transmission interstate pipeline mileage was suitable for ILI, compared to only about half of intrastate pipeline mileage, and therefore, intrastate operators use more pressure testing and DA than interstate operators.

ILIs are performed using tools, 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, unlike pressure testing, ILI does not risk destroying the pipe, and it is typically less costly to perform on a per-unit basis than other assessment methods.

Pressure tests, also known as hydrostatic tests, are 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, water or an alternative 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 is the visual evaluation of a pipeline at a sample of locations along the line to detect corrosion threats, dents, and stress corrosion cracking of the pipe body and seams. In general, corrosion direct assessments are carried out by performing four steps. Operators will review records and other data, then inspect the pipeline through assessments that do not require excavation or use mathematical models and environmental surveys to find likely locations on a pipeline where corrosion is most likely to occur. For external corrosion, operators must use two or more complementary indirect assessment tools, including, for example, close interval surveys, direct current voltage gradient surveys, and alternating current voltage gradient surveys, to determine potential areas of corrosion to examine. For internal corrosion, operators must analyze data to establish whether water was present in the pipe, determine the locations where water would likely accumulate, and provide for a detailed examination and evaluation of those locations. Areas identified where corrosion may be occurring are then excavated, examined visually, and remediated as necessary. Operators also perform a post-assessment on segments where corrosion direct assessments are used to evaluate the effectiveness of the technique and determine re-assessment intervals as needed.[34]

For cracking, operators collect and analyze data to determine whether the conditions for stress corrosion cracking are present, prioritize potentially susceptible segments of pipelines, and select specific sites for examination and evaluation. A DA would then evaluate the presence of

[34] See PHMSA's fact sheet on DA at https://primis.phmsa.dot.gov/Comm/FactSheets/FSdirectAssessmentGas.htm.

stress corrosion cracking and determine its severity and prevalence. Operators are required to repair anomalies, if found, and determine further mitigation requirements as necessary.

Direct assessment can be prohibitively expensive to use on a wide scale and may not give an accurate representation of the condition of lengths of entire pipeline segments when the high expense leads the operator to select an insufficient number of observations. Further, as DA can only be used to validate specific threats, an operator that relies solely on a DA without performing a thorough risk analysis or running multiple tools specific to multiple threats might be leaving other threats unremediated in their pipelines.

Ongoing research and industry response to the ANPRM[35] and NPRM[36] indicate that ILI and spike hydrostatic pressure testing[37] is more effective than DA for identifying pipe conditions that are related to stress corrosion cracking defects. Regulators and operators agree that improving ILI methods as an alternative to hydrostatic testing is better for 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 be destructive.[38] ILI testing can obtain data along a

[35] "Pipeline Safety: Safety of Gas Transmission Pipelines—Advanced Notice of Proposed Rulemaking," 76 FR 5308; August 25, 2011.
[36] "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines," 81 FR 20722; April 8, 2016.
[37] A "spike" hydrostatic pressure test is typically used to resolve cracks that might otherwise grow during pressure reductions after hydrostatic tests or as the result of operational pressure cycles.
[38] 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.

pipeline not otherwise obtainable via other assessment methods, although this method also has certain limitations.[39]

This final rule expands the range of permissible assessment methods and incorporates new guidelines to help operators in the selection of appropriate assessment methods. Promoting the use of ILI technologies, combined with further research and development by PHMSA as well as stakeholders to make ILI testing more accurate, is expected to drive innovation in pipeline integrity testing technologies that leads to improved safety and system reliability through better data collection and assessment.

Flow Reversals, Product Changes, and Manufacturing Defects

Significant growth of production outside the Gulf Coast region—especially in Pennsylvania and Ohio[40]—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 gas from the Marcellus and Utica shale formations to the southeastern Atlantic region and the Midwest.

Reversing a pipeline's flow can cause added stress on the system due to changes in gas pipeline pressure and temperature, which can increase the risk of internal corrosion. Occasional failures on natural gas transmission pipelines have followed operational changes that include flow reversals and product changes.[41] Operators have recently submitted proposed flow reversals and product changes on gas transmission lines. In response to this phenomenon, PHMSA issued

[39] For example, ILI tools are ideal for gathering certain information about the physical condition of the pipe, including corrosion, deformations, or cracking. However, ILI technology cannot reliably detect other conditions, such as coating damage or environmental issues.

[40] U.S. Energy Information Administration, "Annual Energy Outlook 2019," p. 78 – Dry shale gas production by region. https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf

[41] On September 29, 2013, the Tesoro High Plains pipeline leaked 20,000 barrels of crude oil in a North Dakota field. The location of pressure and flow monitoring equipment had not been changed to account for the reversed flow. On March 19, 2013, Exxon's Pegasus pipeline failed; the flow on that pipeline was reversed in 2006.

an Advisory Bulletin in 2014 notifying operators of the potentially significant impacts such changes may have on the integrity of a pipeline and recommended additional actions operators should consider performing before, during, and after flow reversals, product changes, and conversions to service, including notifications, operations and maintenance requirements, and IM requirements.[42]

Data indicates that some pipelines are vulnerable to issues stemming from outdated construction methods or materials. Some gas transmission infrastructure was made before the 1970s using techniques that have proven to contain latent defects due to the manufacturing process. For example, pipe manufactured using low frequency electric resistance welding is susceptible to seam failure. Because these pipelines were installed before the Federal gas regulations were issued, many of those pipes were exempted from certain regulations, most notably the requirement to pressure test the pipeline segment immediately after construction and before placing the pipeline into service. A substantial amount of this type of pipe is still in service.[43] 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 PG&E incident in San Bruno determined that the pipe failed due to a similar defect, a fracture originating in the partially welded longitudinal seam of the pipe. According to PHMSA's accident and incident database, between 2010 and 2017, 30 other reportable incidents were attributed to seam failures, resulting in over $18 million of reported property damage.

[42] "Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes, and Conversion to Service," *ADB PHMSA-2014-0040*, 79 FR 56121; September 18, 2014.
[43] Currently, PHMSA's data shows that roughly 168,000 of the Nation's 301,000 miles of onshore gas transmission pipelines were installed prior to the 1970 requirement for hydrostatic pressure testing. See https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages.

Protecting the Safety and Integrity of the Nation's Pipeline System Beyond HCAs

The current IM program improves pipeline operators' ability to identify and mitigate the risks to their pipeline systems. IM regulations require that operators adopt procedures and processes to identify HCAs; determine likely threats to the pipeline within the HCA; evaluate the physical integrity of the pipe within the HCA; and repair, remediate, or monitor any pipeline defects found based on severity. Because these procedures and processes are complex and interconnected, effective implementation of an IM program relies on continual evaluation and data integration.

HCAs were first defined on August 6, 2002,[44] 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.[45] In a later NPRM,[46] 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.[47] Previously, only distances from the pipeline centerline related to HCA definitions. PHMSA also proposed using Potential Impact Circles (PIC), Potential Impact Zones, and Potential Impact Radii (PIR) to identify covered segments instead of a fixed corridor width. The final Gas Transmission Pipeline

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

[45] 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 based on case-specific pipe size and operating pressure.

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

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

Integrity Management Rule, incorporating the new HCA definition using the PIR and PIC concepts, was issued on December 15, 2003.[48]

The PG&E incident in 2010 motivated a comprehensive reexamination of gas transmission pipeline safety. In response to the PG&E incident, Congress passed the 2011 Pipeline Safety Act, which directed PHMSA 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[49] that IM requirements have reduced the rate of failures due to deterioration of pipe welds, corrosion, and material failures. However, the NTSB noted that pipeline incidents in HCAs due to other factors increased between 2010 and 2013, and the overall occurrence of gas transmission pipeline incidents in HCAs has remained stable. Since 2013 there have been an average of 9 incidents within HCAs, which is below a peak of 12 incidents per year in 2012 and 2013, but still higher than the number of incidents in 2010 and 2011. The NTSB also found many types of basic data necessary to support comprehensive probabilistic modeling of pipeline risks are not currently available.

Looking at Risk Beyond HCAs

PHMSA posed a series of questions to the public in the context of an August 25, 2011, ANPRM titled "Safety of Gas Transmission Pipelines" (76 FR 53086), including whether the regulations governing the safety of gas transmission pipelines needed changing. In particular, PHMSA asked whether to add prescriptive language to IM requirements, and whether other

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

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

issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. PHMSA sought comment on the definition of an HCA and whether additional restrictions should be placed on the use of DA as an IM assessment method. PHMSA also requested comment on non-IM requirements, including valve spacing and installation, corrosion control, and whether regulations for gathering lines needed to be modified.

PHMSA received 103 submissions containing thousands of comments in response to the ANPRM, which are summarized in more detail below. This feedback helped identify a series of proposed improvements to IM, including improvements to assessment goals such as integrity verification, MAOP verification, and material documentation; adjusted 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. PHMSA published an NPRM on April 8, 2016 (81 FR 20722), which is discussed in more detail below.

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.

Section 23 of the 2011 Pipeline Safety Act required PHMSA to have pipeline operators conduct a records verification to ensure that their records accurately reflect the physical and operational characteristics of their pipelines in certain HCAs and class locations, and to confirm the established MAOP of those pipelines. Based on the data received from operators following the records verification, incidents that have occurred in non-HCA areas, and other knowledge gained since the 2011 Pipeline Safety Act was passed, PHMSA has become increasingly concerned that a rupture on the scale of San Bruno, with the potential to cause death and serious injury, as well as damage to the environment or the disruption of commerce, could occur elsewhere on the Nation's pipeline system in both HCA and non-HCA pipeline segments. There have been several recent incidents in non-HCAs that show significant incidents can occur in non-HCAs. For example, 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 owned by Columbia Gulf Transmission Company ruptured. One of the men was killed, and the other was injured.

Further, on December 11, 2012, a 20-inch-diameter gas transmission line operated by Columbia Gas Transmission Company ruptured 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 approximately 14 hours, and the southbound lanes were closed for approximately 19 hours while the road was resurfaced, causing delays to both travelers and commercial shipping.

Finally, on April 29, 2016, an incident occurred on a Texas Eastern Transmission Corporation gas transmission line operated by Spectra Energy near Delmont, PA, which is approximately 25 miles away from Pittsburgh, PA. The explosion seriously injured one person, destroyed a house, damaged three other homes and vehicles outside, and caused the evacuation of nine other homes in the area. Even though the pipeline was in a Class 1 rural area, it still had a significant impact on the local population.

The Nation's population is growing, moving, and dispersing, leading to changes in population density that can affect the class location of a pipeline segment, as well as whether it is in an HCA. The definition of HCA is not necessarily an accurate reflection of whether an incident will have an 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.

Some pipeline operators have said they 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,"[50] 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. To accomplish this goal, INGAA's members committed to 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. These actions aim to extend protection to people who live near pipelines but not within defined HCAs. Further, this final rule takes important steps toward developing a comprehensive approach for the entire industry by finalizing requirements for assessments outside of HCAs.

[50] 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.

This final rule implements risk management standards that most accurately target the safety of communities while also providing sufficient ability to prioritize areas of greatest possible risk and impact.

Given the results of incident investigations, IM considerations, and the feedback from the ANPRM and the NPRM, 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, to achieve the desired outcome of performing assessments in areas where people live, work, or congregate, while balancing the cost of identifying such locations, PHMSA based the requirements for identifying those locations on effective processes already being implemented by pipeline operators and that protect people on a risk-prioritized basis.

Establishing integrity assessment requirements for non-HCA pipeline segments is important for providing safety to the public. Although those pipeline segments are not within defined HCAs, they will usually be in populated areas, and pipeline accidents in these areas may cause fatalities, significant property damage, or disrupt livelihoods. This final rule adopts a newly defined definition for MCAs to identify additional non-HCA pipeline segments that would require integrity assessments, thus assuring the timely discovery and repair of pipeline defects in MCA segments that could potentially impact people, property, or the environment. At the same time, operators can allocate their resources to HCAs on a higher-priority basis.

B. Pacific Gas and Electric Incident of 2010

On September 9, 2010, a 30-inch-diameter segment of a gas transmission pipeline owned and operated by PG&E ruptured in a residential neighborhood in San Bruno, CA, producing a crater approximately 72 feet long by 26 feet wide. The segment of pipe that ruptured weighed approximately 3,000 pounds, was 28 feet long, and was found 100 feet south of the crater. Over the course of the incident, 47.6 million standard cubic feet of natural gas was released. The escaping gas ignited, and the resultant fire destroyed 38 homes, damaged another 70, killed 8 people, injured approximately 60 people (10 seriously), destroyed or damaged 74 vehicles, and caused the evacuation of over 300 more people. The initial 911 calls described the fire as a "gas station explosion" and a "possible airplane crash." After 91 minutes, PG&E was able to shut off the flow of gas to the rupture site, which allowed firefighters to approach the rupture site and begin containment efforts. Firefighting operations continued for 2 days; more than 900 emergency responders from San Bruno and surrounding areas were part of the emergency response, 600 of which were firefighters and emergency medical services personnel. [51]

The NTSB, in its pipeline accident report for the incident, determined that the probable cause of the accident was PG&E's inadequate quality assurance and control when it relocated the line in 1956 and an inadequate IM program. The NTSB determined that PG&E's IM program was deficient and ineffective because it was based on incomplete and inaccurate pipeline information, did not consider the pipeline's design and materials contribution to the risk of a pipeline failure, and failed to consider the presence of previously identified welded seam cracks as part of its risk assessment. These deficiencies resulted in the selection of an examination method that could not detect welded seam defects and led to internal assessments of PG&E's IM program that were superficial and resulted in no improvements. Ultimately, this inadequate IM program failed to detect and repair or remove the defective pipe section.

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[51] National Transportation Safety Board. 2011. *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. Washington, DC.

The NTSB found that PG&E's inaccurate geographic information system records at the time of the incident indicated that the ruptured segment was constructed from 30-inch-diameter seamless API 5L X42 steel pipe. However, seamless pipe has never been available in 30-inch diameter. According to PG&E employees who testified during the investigation, all 30-inch pipe purchased by PG&E at that time would have been double submerged arc welded, which has been found in cases to be susceptible to weld failure. This inaccuracy was compounded with the discovery that the material code from the journal voucher that PG&E's records were originally composed from erroneously indicated the ruptured segment was X52 grade pipe (52,000 pounds per square inch (psi)), not X42 grade pipe (42,000 psi). X52 pipe has a higher minimum yield strength than X42 pipe,[52] and incorporating such values into MAOP calculations would produce values that would be inconsistent with the pipeline's actual MAOP. PG&E also could not produce any design, material, or construction specifications from the 1956 construction project. In short, no one from PG&E could reliably determine what type of pipe was in the ground that ruptured.

The NTSB also noted that PHMSA's exemption of pipelines installed before 1970 from the regulatory requirement for pressure testing, which likely would have detected the installation defects, was a contributing factor to the accident. When the initial Federal minimum safety standards for natural gas transmission pipelines were finalized in 1970, an exemption was carved out for pre-1970s pipelines from the requirement for a post-construction hydrostatic pressure test. This exemption was not proposed in any of the NPRMs that preceded the initial regulations and was based on an assertion from the Federal Power Commission[53] that "there are thousands of

[52] 52,000 psi vs. 42,000 psi.
[53] The predecessor of the Federal Energy Regulatory Commission.

miles of jurisdictional interstate pipelines installed prior to 1952,[54] in compliance with the then-existing codes, that could not continue to operate at their present pressure levels and be in compliance with [the proposed MAOP determination requirements]."[55] Upon reviewing the operating record of interstate pipeline companies, the Commission found "no evidence that would indicate a material increase in safety would result from requiring wholesale reductions in the pressure of existing pipelines which have been proven capable of withstanding present operating pressures through actual operation." The Office of Pipeline Safety, at the time, determined it "[did] not now have enough information to determine that existing operating pressures are unsafe," and taking into account the statements from the Federal Power Commission, included the "grandfather" clause in the final rule to permit the continued operation of pipelines at the highest pressure to which the pipeline had been subjected during the 5 years preceding July 1, 1970.[56,57] The 5-year limit was prescribed so that operators would be prevented from "using a theoretical MAOP which may have been determined under some formula used 20, 30, or 40 years ago."[58]

The NTSB noted in its investigation that the "grandfathering" of the ruptured line resulted in missed opportunities to detect the defective pipe, as a hydrostatic pressure test to the prescribed levels for a Class 3 location would likely have exposed the defective pipe that led to the accident. Following the PG&E incident, the California Public Utilities Commission (CPUC) required PG&E and other gas transmission pipeline operators regulated by CPUC to either

[54] Between 1935 and 1951, the B31 Code only required a pipeline be tested to a pressure of 50 psig in excess of the pipeline's proposed MAOP. The 1970 regulations required pressure testing to 125 percent in excess of the proposed MAOP.
[55] "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards," 35 FR 13248; August 19, 1970.
[56] 35 FR 13248
[57] This requirement is currently under § 192.619(c).
[58] 35 FR 13248

hydrostatically pressure test or replace certain transmission pipelines with grandfathered MAOPs, stating that gas transmission pipelines "must be brought into compliance with modern standards for safety" and that "historic exemptions must come to an end."[59] Currently, PHMSA's data shows that roughly 168,000 of the Nation's 301,000 miles of onshore gas transmission pipelines were installed prior to the 1970 requirement for hydrostatic pressure testing.[60]

On April 1, 2014, the Department of Justice indicted PG&E for multiple criminal violations of part 192 for the 2010 incident in San Bruno, CA. The trial began on June 14, 2016, and after a 5 ½ week trial, a Federal jury found PG&E guilty of knowingly and willingly violating 5 sections of PHMSA's IM regulations and obstructing the NTSB investigation.

Specifically, with respect to the Federal Pipeline Safety Regulations, the jury found that between 2007 and 2010, PG&E knowingly and willfully failed to: 1) gather and integrate existing data and information that could be relevant to identifying and evaluating potential threats on covered pipeline segments; 2) identify and evaluate all potential threats to each covered pipeline segment; 3) include in its baseline assessment plan all potential threats on a covered segment and to select the most suitable assessment method; 4) prioritize high-risk pipeline segments for assessment where certain changed circumstances rendered the manufacturing threats on those segments unstable; and 5) prioritize pipeline segments containing low-frequency ERW pipe or other similar pipe as a high-risk segment for assessment if certain changed circumstances rendered a manufacturing seam threat on that segment unstable.

Congress required PHMSA, per the 2011 Pipeline Safety Act, to issue regulations to confirm the material strength of previously untested natural gas transmission pipelines located in

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[59] "Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans;" California Public Utilities Commission Order; June 9, 2011.
[60] https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?PortalPages

HCAs and operating at a pressure greater than 30 percent of SMYS. Through this final rule, PHMSA is implementing that congressional directive and other safety measures. This final rule will improve the safety and public confidence of the Nation’s onshore natural gas transmission pipeline system.

C. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an ANPRM to seek public comments regarding the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines. In the 2011 ANPRM, PHMSA requested comments on 122 questions spread through 15 broad topic areas covering both IM and non-IM requirements. Among the issues related to IM that PHMSA considered included whether the definition of an HCA should be revised and whether additional restrictions should be placed on the use of certain pipeline assessment methods. PHMSA also requested comment on non-IM regulations, including whether revised requirements are needed for mainline valve spacing and actuation, whether requirements for corrosion control should be strengthened, and whether new regulations are needed to govern the safety of gas gathering lines and underground natural gas storage facilities. Based on the comments received on several of the ANPRM topics, PHMSA developed proposals for some of those topics in a NPRM that is the basis for this final rule. That NPRM and the comments received, are discussed below. PHMSA did not find it appropriate to address all the topics in a single rulemaking. Those topics that were not discussed further in the NPRM for this final rule have been discussed or will be discussed in other rulemakings.

D. National Transportation Safety Board Recommendations

On August 30, 2011, following the issuance of the ANPRM, the NTSB adopted its report on the gas pipeline incident that occurred on September 9, 2010, in San Bruno, CA. On September 26, 2011, the NTSB issued safety recommendations P-11-8 through -20 to PHMSA. Several of the NTSB's recommendations related directly to the topics discussed in the 2011 ANPRM and 2016 NPRM, and they shaped the direction of this final rule. The NTSB recommendations addressed in this final rule include:

- 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*."
- 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."*
- Incorporating interstates, highways, etc., into the list of "identified sites" that establish a HCA. NTSB Recommendation P-14-1: *"Revise Title 49 CFR Section 903, Subpart O, Gas Transmission Pipeline Integrity Management, 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 an HCA.*

- Increase the use of ILI tools. NTSB Recommendation P-15-20: "*Identify all operational complications that limit the use of in-line inspection tools in piggable pipelines, develop methods to eliminate the operational complications, and require operators to use these methods to increase the use of in-line inspection tools.*"

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

The 2011 Pipeline Safety Act relates directly to the topics addressed in PHMSA's ANPRM of August 25, 2011, and the NPRM issued on April 8, 2016. 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 the expansion of IM system requirements, or elements thereof, beyond HCAs, if appropriate.
- Section 23 – Requires the reporting of each exceedance of the MAOP that exceeds the build-up allowed for the operation of pressure-limiting or -control devices.
- Section 23 – Requires testing to confirm the material strength of previously untested natural gas transmission pipelines and pipelines lacking records that accurately reflect the pipeline's physical and operational characteristics.
- Section 29 – Requires consideration of seismicity when evaluating pipeline threats.

F. *Notice of Proposed Rulemaking*

On April 8, 2016, PHMSA published an NPRM seeking public comments on the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines and gas gathering pipelines (81 FR 20721).[61] When developing the NPRM, PHMSA considered the comments it received from the ANPRM and proposed new pipeline safety requirements and revisions of existing requirements in several major topic areas, including those topics addressing congressional mandates and related NTSB recommendations. A summary of the NPRM proposals and topics pertinent to this rulemaking, the comments received on those specific proposals, and PHMSA's response to the comments received is below under the "Analysis of Comments and PHMSA Response" section.

PHMSA determined it could more quickly move a rulemaking that focuses on the mandates from the 2011 Pipeline Safety Act by splitting out the other provisions contained in the NPRM into two other, separate rules. Promptly issuing a final rule focused on mandates will improve safety and respond to Congress, industry, and public safety groups.

As such, not all the topics from the NPRM nor the comments received on those topics are discussed as a part of this rulemaking. PHMSA intends to issue two additional final rules to address the remaining topics from the NPRM.

III. Analysis of NPRM Comments, GPAC Recommendations, and PHMSA Response

On April 8, 2016, PHMSA published an NPRM (81 FR 20722) proposing several amendments to 49 CFR part 192. The NPRM proposed amendments addressing topic areas including verification of pipeline material properties, MAOP reconfirmation, IM clarifications,

[61] https://www.regulations.gov/document?D=PHMSA-2011-0023-0118

MAOP exceedance reports, ILI launcher and receiver safety, assessing areas outside of HCAs, and recordkeeping. The comment period for the NPRM ended on July 7, 2016. PHMSA received approximately 300 submissions containing thousands of comments on the NPRM. Submissions were received from groups representing the regulated pipeline industry; groups representing public interests, including environmental groups; State utility commissions and regulators; members of Congress; specific pipeline operators; and private citizens.

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

The remaining comments reflect a wide variety of views on the merits of particular sections of the proposed regulations. PHMSA read and considered all the comments posted to the docket for this rulemaking.

The Technical Pipeline Safety Standards Committee, commonly known as the Gas Pipeline Advisory Committee (GPAC; the committee), is a statutorily mandated advisory committee that advises PHMSA on proposed safety standards, risk assessments, and safety policies for natural gas pipelines.[62] The GPAC is one of two pipeline advisory committees that focus on technical safety standards that were established under the Federal Advisory Committee Act (Pub. L. 92-463, 5 U.S.C. App. 1-16) and section 60115 of the Federal Pipeline Safety Statutes (49 U.S.C. Chap. 601). Each committee consists of 15 members, with membership

[62] 49 U.S.C. § 60115.

divided among Federal and State agencies, regulated industry, and the public. The committees consider the "technical feasibility, reasonableness, cost-effectiveness, and practicability" of each proposed pipeline safety standard and provide PHMSA with recommended actions pertaining to those proposals.

Due to the size and technical detail of this rulemaking, the GPAC met five times to discuss this rulemaking throughout 2017 and 2018.[63] During those meetings, the GPAC considered the specific regulatory proposals of the NPRM and discussed various comments made on the NPRM's proposal by stakeholders, including the pipeline industry at large, public interest groups, and government entities. To assist the GPAC in its deliberations, PHMSA presented a description and summary of the major proposals in the NPRM and the comments received on those issues. PHMSA also assisted the committee by fostering discussion and developing recommendations by providing direction on which issues were most pressing.

For the proposals finalized in this rulemaking, the committee came to consensus when voting on the technical feasibility, reasonableness, cost-effectiveness, and practicability of the NPRM's provisions. In many instances, the committee recommended changes to certain proposals that the committee found would make certain proposals more feasible, reasonable, cost-effective, or practicable.

The substantive comments received on the NPRM as well as the GPAC's recommendations are organized by topic below and are discussed in the appropriate section with PHMSA's response and resolution to those comments.

[63] Specifically, the GPAC met on January 11-12, 2017; June 6-7, 2017; December 14-15, 2017; March 2, 2018; and March 26-28, 2018. Information on these meetings can be found at regulations.gov under docket PHMSA-2011-0023 and at PHMSA's public meeting page: https://primis.phmsa.dot.gov/meetings/.

A. Verification of Pipeline Material Properties and Attributes - § 192.607

i. – Applicability

1. Summary of PHMSA's Proposal

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the 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 gas transmission pipelines. Since 2012, operators have submitted information indicating that a portion of transmission pipeline segments do not have adequate records to establish MAOP or that accurately reflect the physical and operational characteristics of the pipeline. Therefore, PHMSA determined that additional regulations are needed to implement this requirement of the 2011 Pipeline Safety Act. Specifically, PHMSA proposed that operators conduct tests and other actions needed to confirm and document the physical and operational characteristics for those pipeline segments where adequate records are not available, and PHMSA proposed standards for performing these actions. PHMSA sought to appropriately address pipeline risk without extending the requirement to all pipelines where risk and potential consequences are not as significant, such as pipelines in remote, sparsely-populated areas. As a result, PHMSA proposed criteria that would require material properties verification for higher-risk locations through a new § 192.607; specifically, by adding requirements for the verification of pipeline material properties for existing onshore, steel, gas transmission pipelines that are located in HCAs or Class 3 or Class 4 locations.

2. Summary of Public Comment

Several citizen and public safety groups, including Pipeline Safety Trust (PST), Pipeline Safety Coalition, National Association of Pipeline Safety Representatives (NAPSR), Coalition to Reroute Nexus, Earthworks, and The Michigan Coalition to Protect Public Rights-of-Way, supported the proposed provisions for establishing adequate material properties documentation and records. Some of these groups noted that the need for this section in the regulations would suggest poor operator implementation of the IM requirements since the inception of subpart O back in 2003.

Trade associations and pipeline industry entities were largely opposed to the material properties verification requirements for several reasons outlined below.

Many trade association and pipeline industry commenters expressed concern that the material properties verification requirements were potentially retroactive. American Petroleum Institute (API) and American Gas Association (AGA) asserted that this proposal would require operators to document and verify the material properties of existing pipelines beyond what was required by the regulations that were in place at the time those pipelines were put into service. These commenters stated that this retroactive requirement extends beyond the congressional authority provided to PHMSA. Several commenters, including AGL Resources, Dominion East Ohio, and New Jersey Natural Gas, expressed concern with the proposed provisions for verifying specific physical characteristics of pipelines, fittings, valves, flanges, and components for existing transmission pipelines. These stakeholders stated that it might be impossible to achieve "reliable, traceable, verifiable, and complete" records on a retroactive basis for existing pipelines. Some commenters, including AGA, stated that a pipeline’s MAOP should be considered confirmed and there should be no need to further document material properties to verify the

MAOP if operators had a pressure test record of a test conducted at 1.25 times MAOP for the pipeline segment.

Commenters also expressed concern about PHMSA's proposed new references to the material properties verification requirements under § 192.607 throughout part 192, which could be interpreted as being applicable not only to a subset of transmission pipelines but also to distribution pipelines. Commenters stated that PHMSA did not provide justification within the NPRM for applying material properties verification requirements to distribution systems, and such requirements would significantly impact distribution systems. These commenters requested that PHMSA explicitly exclude distribution pipelines from the proposed material properties verification requirements. Similarly, some commenters urged PHMSA to restrict these requirements only to gas transmission lines operating at greater than 30 percent SMYS based on the premise that lines operating below 30 percent SMYS, in most cases, tend to leak before rupture and are therefore less risky to the public. Additionally, commenters suggested that PHMSA review the various cross-references in the NPRM and eliminate those that would expand the applicability of the material properties verification requirements beyond onshore steel gas transmission pipelines in HCAs and Class 3 and Class 4 locations.

Some commenters recommended changing the size limit for small components that might trigger the material properties verification requirements from greater-than-or-equal-to 2 inches to greater-than 2 inches. A further comment on components discussed how the material properties verification provisions, as proposed, require the operator to know the weld-end bevel conditions for in-service valves and flanges. Operators noted, however, that once a weld-end is welded to a piece of pipe or other component, there is no method that can be employed to determine the condition of that bevel. Accordingly, the commenters requested this requirement be deleted or clarified. There was also a comment to delete the sampling requirement and not perform material properties verification if, when the applicable pipeline is excavated for repairs, a repair sleeve is installed. Other commenters felt that the proposed material properties verification requirements would not deliver clear, identifiable safety benefits and would lead to several unintended consequences that would decrease the integrity of pipeline systems and cause energy supply disruption. Accordingly, these commenters suggested PHMSA withdraw the proposed requirements for material properties verification.

Multiple commenters also expressed concerns that the revised provisions for establishing MAOP under § 192.619, specifically the requirement for operators to maintain all records necessary to establish and document a pipeline's MAOP as long as the pipeline remains in service, would impose extensive new recordkeeping requirements applicable to operators of distribution pipelines, including retroactive recordkeeping requirements. Commenters requested that PHMSA clarify that the new recordkeeping requirements in § 192.619(f) are applicable only to gas transmission pipelines.

Pipeline industry entities also provided comments on the relationship of the material properties verification requirements in § 192.607 and the MAOP reconfirmation requirements in § 192.624. The Gas Piping Technology Committee (GPTC) suggested that the proposed material properties verification requirements be revised to include an option of using the provisions of § 192.619(a)(1) for establishing MAOP when traceable, verifiable, and complete material property records are not available for calculating design pressure. Similarly, commenters suggested operators should be allowed to establish design yield strengths for unknown pipe grade as described at § 192.107(b)(1). Xcel Energy also stated that if an operator has previously established MAOP as per the § 192.619(a)(2) strength test requirements or will do so per the proposed § 192.624 methodology for pressure test or pressure reduction, the verification of pipeline material proposed in § 192.607 is not necessary for the purpose of ensuring safe operation.

Over the course of the meetings on June 7, 2017, and December 14, 2017, the GPAC had a robust discussion regarding the applicability of the material properties verification requirements. More specifically, the GPAC discussed the fact that two separate activities drive the need for material properties verification: 1) MAOP reconfirmation for pipelines lacking traceable, verifiable, and complete records to support the pipeline's current MAOP; and 2) the application of IM principles, especially where anomaly response and remediation calculations are concerned. The GPAC believed these aspects needed to be addressed separately in the final rule.

Subsequently, on December 14, 2017, the GPAC recommended that PHMSA modify the proposed rule by removing the applicability criteria of the material properties verification requirements and make material properties verification a procedure for obtaining missing or inadequate records or otherwise verifying pipeline attributes if and when required by MAOP reconfirmation requirements or by other code sections. In discussing the issue, the GPAC recognized that the broad applicability of the material properties verification requirements in the proposed rule was PHMSA's attempt to address the issue of inadequate records for MAOP verification, IM requirements and standard pipeline operations. The GPAC believed amending the proposed rule to remove the proposed applicability and instead explicitly refer back to the material properties verification requirements, when needed, in various regulatory sections, would more closely follow Congress' direction in the 2011 Pipeline Safety Act.

This change would also obviate the need for operators to create a material properties verification program plan per the originally proposed requirements, so the GPAC recommended PHMSA remove that requirement from the rule. Further, the committee recommended during a later meeting that PHMSA consider modifying the rule in both §§ 192.607 and 192.619 to clarify that the material properties verification requirements apply to onshore steel gas transmission lines and not to distribution or gathering pipelines.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the scope and requirements for reconfirming the material properties of pipelines with unknown or undocumented properties. PHMSA agrees that the need for this rule is caused, in part, by poor implementation of existing IM requirements. However, PHMSA disagrees that the requirements would not deliver safety benefits or would lead to decreased integrity of pipeline systems and cause energy supply disruption. The basic knowledge of pipeline material properties is essential to pipeline safety.

PHMSA disagrees that material properties verification is not needed if the pipeline segment has been pressure tested to 1.25 times MAOP. Other reasons for needing documented, confirmed material properties (e.g., wall thickness, yield strength, and seam type) include IM program requirements, implementation of pipe repair criteria and determination of the design pressure of the pipeline segment. This rule supplements existing IM requirements by providing operators a method to reconfirm material properties without necessarily performing destructive testing of the pipe material. Operators can use this method in their IM programs, to reconfirm MAOP where needed, to implement repair requirements, and to otherwise comply with part 192 where necessary. Indeed, PHMSA hopes that operators will use this method for material properties verification even when not specifically required by part 192 because it provides a common-sense, opportunistic, and practical approach for gathering the records necessary to substantiate safe MAOPs, properly implement IM, and otherwise ensure the safe operation of the nation's pipeline network.

PHMSA also disagrees that material properties verification is only needed for pipeline segments operating at pressure greater than 30 percent of SMYS. IM requirements apply to all gas transmission pipeline segments in HCAs, including those that operate at less than 30 percent of SMYS. Moreover, the gas transmission subpart O integrity management regulations at § 192.917(b), *Data gathering and integration,* require operators to gather pipe attributes including pipe wall thickness, diameter, seam type and joint factor, manufacturer, manufacturing date, and material properties. These physical properties and attributes are explicitly outlined in ASME/ANSI B31.8S – 2004 Edition, section 4, table 1 - Data Elements for Prescriptive Pipeline Integrity Program, which is incorporated by reference in § 192.7.

PHMSA did not intend that the requirements proposed in § 192.607 would be retroactive or would apply to distribution or gathering lines. Therefore, PHMSA is clarifying the final rule to assure that the provisions finalized in § 192.607 are not retroactive[64] and apply only to transmission lines. However, PHMSA believes that operators with IM programs that are properly following subpart O, specifically § 192.917(b), should already have this pipe information.

[64] The material properties verification requirements are not retroactive as they mandate the creation and retention of records as operators execute the methodology in § 192.607 on a prospective basis. Operators who have not verified their records in accordance with this methodology before the effective date of this rule will not be subject to enforcement action based on § 192.607. After the effective date of the rule, operators with missing or inadequate records must follow the verification methodology in § 192.607.

Regarding material properties verification for non-line pipe components, PHMSA is revising this final rule to apply the requirements to components greater than 2 inches and is removing the requirement to know the weld-end bevel conditions. PHMSA agrees with the GPAC members who commented that 2-inch pipe is not used in mainline applications and need not be subject to additional regulatory requirements to maintain safety. Also, fittings and flanges will have an ANSI class rating that will confirm whether the components meet or exceed the MAOP of the pipeline, so further regulatory requirements for components under 2 inches are not necessary to maintain safety.

To further address comments and the GPAC recommendations related to the scope and applicability of the material properties verification requirements, PHMSA is modifying this final rule to address MAOP reconfirmation and material properties verification separately from the application of IM principles. PHMSA believes this change will improve the organization of the rule. PHMSA is accomplishing this by removing the applicability criteria of the material properties verification requirements and making material properties verification a procedure for obtaining records for physical pipeline properties and attributes that are not documented in traceable, verifiable, and complete records or otherwise verifying physical pipeline properties and attributes when required by MAOP reconfirmation requirements, IM requirements, repair requirements, or other code sections. This obviates the need for all operators to create a material properties verification program plan per the originally proposed requirements, so PHMSA is removing that requirement from the rule as well. Instead, only operators who do not have traceable, verifiable, and complete records will be required to create such a plan.

A. Verification of Pipeline Material Properties and Attributes - § 192.607

ii. – Method

1. Summary of PHMSA's Proposal

The conventional method for determining the properties of unknown steel pipe material is to cut test specimens known as "coupons" out of the pipe and perform destructive testing. Because of the large amount of pipe operators reported in Annual Report submissions for which there are unknown or inadequately documented properties, the cost of such a conventional approach would likely be onerous. Therefore, PHMSA proposed standards in § 192.607 by which operators could develop a material properties verification plan and use an opportunistic sampling technique to re-constitute and document material properties in a more cost-effective manner. More specifically, PHMSA proposed to allow operators to use recently developed technology to perform *in situ*, non-destructive examinations for determining the properties of unknown steel pipe material.

While PHMSA acknowledged in the preamble of the NPRM that such techniques may not be possible in every situation, PHMSA stated that it was aware that this option is already being widely deployed in the pipeline industry. Secondly, PHMSA proposed to allow operators to determine pipe properties at a sampling of similar locations and apply those results to the entire population of pipeline segments. PHMSA proposed to allow operators to take advantage of opportunities when the pipeline is exposed for other reasons, such as during maintenance and repair excavations, by requiring that material properties be verified whenever the pipe is exposed. This would reduce the number of excavations that might otherwise be required. Excavations are a large portion of the cost of re-constituting material properties for unknown pipe.

2. Summary of Public Comment

Several commenters suggested that the data required by the material properties verification process proposed by PHMSA can be obtained only through destructive pipe testing. These commenters asserted that the proposed requirements would lead to unnecessary service outages, increased methane emissions, and increased personnel safety risks due to unnecessary excavation activities. Black Hills Energy stated that their pipeline system consists of mainly smaller-diameter transmission pipelines and that the proposed provisions would force them to take lines out of service to perform costly cutouts. API asserted that the expense and risk required for the excavations necessary to comply with the proposed provisions outweigh the value of obtaining and documenting material pipe properties. Some commenters suggested that it would be less costly for operators to simply replace pipe rather than obtain the material properties for pipe already in the ground. A commenter asserted that the proposed requirements would require unnecessary breaching of the pipeline coating, which is important for effective cathodic protection. API suggested that rather than requiring operators to gather documentation on material properties that may only be of marginal value for assessing pipeline safety, PHMSA should require a combination of hydrostatic pressure testing and ILI. API stated that, as opposed to the proposed rule’s focus on the precise documentation of materials, this would appropriately shift the emphasis of the proposed regulations to confirming MAOP and away from material properties verification.

Several commenters stated that some of the data that PHMSA proposed operators verify is unnecessary for MAOP reconfirmation or other operational reasons. For example, the Interstate Natural Gas Association of America (INGAA) stated that several of the data elements that would need to be verified pursuant to the proposed material properties verification requirements are unnecessary for integrity management-related activities. Commenters suggested that PHMSA limit the required records to what is needed to calculate design pressure in order to determine MAOP. Commenters noted that the proposed requirements would require testing for stress corrosion cracking (SCC) in all cases, and that the requirement should be limited to only pipelines that are susceptible to SCC. Some commenters disagreed with the requirement to determine and keep a record for the chemical composition of steel transmission pipeline segments installed prior to the effective date of the final rule, suggesting that this information has not been previously required. Another commenter stated that the basis for having accurate chemical composition records is unclear. PG&E recommended that PHMSA recognize that chemical composition and manufacturing specifications provide limited information that can be used to evaluate the safety of an existing pipeline system. Piedmont Natural Gas stated that any requirement to retroactively obtain ultimate tensile strength and chemical composition is unnecessarily burdensome and detracts from the ultimate goal of pipeline safety by diverting valuable resources away from other risk-reduction efforts. A similar comment asserted there was no benefit in determining pipeline chemical compositions, as there is a high probability that many pipelines that might otherwise have adequate material documentation would fail the recordkeeping requirements because of a lack of existing chemical composition records and would subsequently be subject to the entire material properties verification process.

Pipeline industry entities also commented on the proposed sampling and testing requirements that would occur during excavations. Commenters asserted that the sampling requirements should be removed, and the number of excavations should not be specified. One commenter stated that the minimum number of excavations should be determined by the operator in their material properties verification plan and through statistical analysis aimed at achieving targeted confidence levels. Texas Pipeline Association (TPA) stated that there is no technical justification for the number of material properties tests being required at each test location by the proposed rule, and that the requirement of five tests in each circumferential quadrant for non-destructive tests and one test in each circumferential quadrant for destructive tests is unsupported in the proposal. TPA further stated that they are unaware of any indication that there is great variability in material properties within the body of a pipe, and that presently, material properties verification involves a single test per cylinder. Additionally, commenters stated this requirement could be unnecessarily costly and have a negative impact on pipeline safety, as the integrity of the pipeline would need to be compromised to perform these evaluations and a new joint of pipe would need to be welded onto the existing pipeline. Lastly, Spectra Energy Partners objected to the requirement that non-destructive testing be validated with unity plots comparing the results from non-destructive and destructive testing. They stated that this severely limits the value of non-destructive testing since the operator will have to remove samples for destructive testing to create the unity plots.

CenterPoint Energy stated that the definition of excavation is unclear, and that pipe may be excavated to a point for many operational activities, including spotting for construction safety and installing cathodic protection tests or current source wires. CenterPoint Energy stated that they do not view these types of excavations as opportunities for material properties verification data gathering because that would require the full exposure of a pipeline segment and the removal of good coating from the pipe. Another commenter suggested that confidence specifications for non-destructive testing would add significant cost due to inherently inaccurate test results.

Similarly, there were comments that encouraged consistency between the material properties verification requirements and the requirements for recordkeeping for materials, pipe design, and pipeline components. These comments suggested that inconsistencies between the documentation and the recordkeeping requirements could create scenarios where operators meet the recordkeeping requirements but do not have adequate documentation to prevent the material properties verification requirements from triggering.

Some commenters opposed the proposed requirement to obtain a “no objection” letter from PHMSA in order to use a new or other technology. PG&E recommended that PHMSA provide additional regulatory language to allow an operator to proceed with the new technology if a "no objection letter" to PHMSA is not received within 45 days prior to the planned use of technology. They stated that operators put in considerable time to set up contracts, schedule work, acquire permits, and that waiting on an approval or disapproval from PHMSA can dramatically impact schedule and costs. Further, commenters suggested that PHMSA’s enforcement and regulatory procedures do not provide for “no objection” letters, and adding a new process that is not well-defined could cause additional confusion.

AGA proposed an alternative approach to material properties verification, MAOP reconfirmation, and integrity assessments outside of HCAs, which other pipeline industry entities supported. The approach included requiring operators to either pressure test or utilize an alternative technology that is determined to be of equal effectiveness on high-risk gas transmission pipelines that do not have a record of a subpart J pressure test or are currently utilizing the grandfather clause for MAOP determination (§ 192.619(c)). AGA suggested a three-tiered approach that prioritized pipelines located in HCAs and operating at pressures greater than 30 percent SMYS. The approach also included the use of ILI tools on all gas transmission pipelines that are able to accommodate inspection by means of an instrumented ILI tool. The ILI tool used would be qualified to find defects that would fail a subpart J pressure test. Commenters stated that this alternative approach is simpler and would allow operators to focus resources on the areas of highest risk within pipeline systems. In conjunction with AGA's approach, commenters recommended including language that would allow the use of advanced ILI and non-destructive evaluations to comply with the proposed material properties verification requirements.

Certain commenters also suggested PHMSA provide a deadline by which operators must implement their material properties verification plan, as it was unclear in the proposal. Following committee discussion and PHMSA feedback, industry groups also recommended to allow operators to use their own statistical sampling plans when undertaking material properties verification rather than have PHMSA specify the number of samples that must be obtained.

At the GPAC meeting on December 14, 2017, the committee recommended that PHMSA modify the method for material properties verification by clarifying that operators are only required to confirm attributes pertinent to the goal of MAOP reconfirmation, integrity management, or other reasons when the material properties verification is being performed. The GPAC also recommended that PHMSA require operators keep records developed using the material properties verification method. The GPAC recommended that PHMSA retain the opportunistic approach of obtaining unknown or undocumented material properties when excavations are performed for repairs or other reasons, using a one-per-mile standard proposed by PHMSA, but allow operators to propose an alternative statistical approach and submit a notification to PHMSA with justification for their method. The GPAC also recommended that if operators notify PHMSA of an alternative sampling approach, and the operator does not receive an objection letter from PHMSA within 90 days of such a notification, the operator can proceed with their chosen method unless PHMSA notifies the operator that additional review time or additional information from the operator is needed for PHMSA to complete its review.

Similarly, the committee recommended PHMSA delete specified program requirements for how to address sampling failures and replace that with a requirement for operators to determine how to deal with sample failures through an expanded sample program that is specific to their system and circumstances. They further recommended that PHMSA require operators to notify PHMSA of the expanded sample program and establish a minimum standard that sampling programs must be based on a minimum 95 percent confidence level.

Further, the committee recommended that PHMSA retain the flexibility for operators to conduct either destructive or non-destructive tests when material properties verification is needed and requested PHMSA drop accuracy specifications but retain the requirement that any test methods used be validated and be performed with calibrated equipment. The GPAC also recommended PHMSA reduce the number of quadrants at which non-destructive evaluation tests be made from four to two.

Regarding the number of test locations and the number of excavations that must be performed, the GPAC recommended PHMSA accommodate situations where a single material properties verification test is needed (e.g., additional information is needed for an anomaly evaluation/repair) and drop the mandatory requirements for testing multiple joints for large excavations. The GPAC also recommended PHMSA clarify the applicability of the requirements for developing and implementing procedures for conducting material properties verification tests on populations of undocumented or inadequately documented pipeline segments and the minimum number of excavations and tests that must be performed for those pipeline segments.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the method for material properties verification. PHMSA disagrees with implementing the alternative approach proposed by AGA, but the underlying comments of AGA and others related to having an alternative approach are discussed in this rulemaking and are addressed below. PHMSA strongly believes that knowledge of pipeline physical properties and attributes are essential for a modern IM program (see § 192.917(b) – *Data gathering and integration*) as well as effective pipeline and public safety. The PG&E incident at San Bruno, CA, was caused, in part, by PG&E mistakenly classifying the pipe that failed as seamless pipe. That pipe was welded seam pipe, and the failure occurred at a partially welded seam.

The NPRM included a list of material properties that could be confirmed using the material properties verification process. One of them in particular, steel toughness, is conventionally obtained only through destructive testing. It was not PHMSA's intent that toughness would need to be confirmed every time an operator was performing material properties verification, thus in effect requiring destructive testing for every location. Therefore, PHMSA is modifying this final rule to address toughness properties in a separate paragraph and is allowing the use of techniques that are reliable without specifying destructive testing. This is intended to accommodate new, non-destructive techniques currently under development. The new paragraph with these requirements also makes it clear that toughness is required only where needed and not necessarily in every case. PHMSA is also modifying other sections of this final rule to provide reasonably conservative default toughness values so that operators may achieve the goals of IM and MAOP reconfirmation using assumed values without the need for destructive testing. These changes will be discussed further in subsequent sections of this document.

Similarly, PHMSA is modifying the verbiage related to the listing of material properties to which the material properties verification process would apply. The clarification will make it clear that the material properties verification process only applies to the pertinent properties needed to achieve the goals of the activity for which material properties verification is needed, such as MAOP reconfirmation or IM. This avoids the potential for requiring that all properties be documented each time an operator goes out to perform material properties verification when only a subset of properties is needed.

PHMSA is also replacing the prescriptive accuracy specifications and unity plot validation for non-destructive testing with more general verbiage that requires that methods are validated and that operators account for the accuracy of the method used. This change will help accommodate new technology and techniques currently under development and avoid situations that might require destructive testing to validate the non-destructive methods.

In response to the comments, PHMSA is relaxing the number of test points for non-destructive tests from four quadrants to two quadrants. This allows the operator to perform material properties verification on the top half of the pipe and would avoid the need to access the bottom half of the pipe when the repair or maintenance activity would not otherwise require it. PHMSA is also removing the proposed requirement to conduct material verification at multiple locations within a single large excavation based on the number of joints of line pipe exposed. PHMSA believes the methods described in this final rule will provide operators accurate material properties information without requiring more excavation activities than necessary.

In this final rule, PHMSA is modifying § 192.607 to specifically list the types of excavations where operators that need to verify material properties should seek to conduct material properties verification. This revision intends to avoid requiring operators perform the material properties verification process at partial excavations that do not expose the pipeline segment. For example, PHMSA considers excavations associated with direct examinations of anomalies to be an opportunity to perform material properties verification. Similarly, PHMSA is modifying the language to acknowledge the need to perform one-time material properties verification activities at specific locations, such as when performing repairs. An operator who has complete material documentation for a particular pipeline segment would not need to undertake the sampling program at excavations on that particular segment. The sampling program is specifically required when the operator needs to document material properties for entire segments of pipelines.

PHMSA disagrees with the removal of the number of samples needed and is maintaining the minimum standard to define the number of excavations in the sampling program as 1 per mile or 150 if the population of pipeline segments is more than 150 miles, whichever is less. However, PHMSA is modifying the rule to provide operators the option of proposing an alternative sampling program if they send a notification and justification of the alternative program to PHMSA in accordance with the new notification procedures at § 192.18. Operators may use an alternative sampling program 91 days after submitting a notification per § 192.18 to PHMSA if the operator has not received a letter of objection or a request from PHMSA for more time to review.

PHMSA is also withdrawing the expanded sampling requirements to address cases where operators identify problems in the initial sampling program. Instead, operators may use an alternative sampling approach that addresses how the operator's sampling plan will address findings that reveal physical pipeline properties and attributes that are not consistent with all available information or existing expectations or assumed physical pipeline properties and attributes used for pipeline operations and maintenance in the past. Operators taking such an approach must notify PHMSA of the adverse findings and provide PHMSA with specific details of the alternative sampling plan with a justification for such a plan in a notification to PHMSA. The alternative sampling program must be designed to achieve a 95 percent confidence level. In accordance with the new notification procedures at § 192.18, operators may use an alternative sampling plan 91 days after submitting a notification to PHMSA if the operator has not received a letter of objection or a request from PHMSA for more time to review.

In response to committee discussion, PHMSA is modifying its notification process broadly throughout part 192 to allow operators to propose using methods and technologies by notifying PHMSA in accordance with the new procedures in § 192.18. If an operator does not receive a letter of objection or a request from PHMSA for more time to review within 90 days of the notification, then the operator may use the proposed method or technology. Some committee members were concerned that some provisions throughout the NPRM would require action from PHMSA in the form of a "no objection" letter. Members noted that such a process can leave companies unable to proceed until PHMSA provided affirmative approval of the request. Committee members suggested that it may be more efficient and less burdensome for PHMSA to issue letters to operators only when they specifically object to proposed plans or solutions, and otherwise allow the operator to proceed as planned in the absence of such a letter. Other members were concerned that PHMSA might authorize sub-optimal plans or technologies by missing a deadline. To this end, members recommended an approach where PHMSA could request additional time for review beyond the 90-day period. PHMSA noted at the meeting that this is a similar process that is used by PHMSA for state waivers and the change should improve regulatory efficiency.

PHMSA's letter or e-mail of objection will specify the reasons PHMSA does not approve of the proposed method or technology, while a request from PHMSA for more time to review the notification will extend the review period beyond 90 days. Further, to establish a verifiable record, it will be PHMSA's policy to send a "no objection" letter or e-mail, either before or after the 90-day review period, when PHMSA does not object to an operator's proposed method or technology. PHMSA is applying this approach to other places in this rulemaking that require notifications and has created a general notification provision in subpart A of part 192.

PHMSA is modifying the recordkeeping requirement for the material properties verification provisions to avoid potential conflicts with other provisions in this rulemaking, such as MAOP reconfirmation, to clarify that operators are required to keep any records created, for the life of the pipeline, when verifying specific properties using the methods in § 192.607. These records must also be traceable, verifiable, and complete. These recordkeeping requirements are not retroactive, as they mandate the creation and retention of records as operators execute the methodology in § 192.607 on a prospective basis.

PHMSA disagrees with commenters that asked for PHMSA to establish a deadline for operators to complete the sampling programs. The opportunistic approach PHMSA proposed and retained for this final rule requires material properties verification activities to occur at excavation sites where operators are directly examining anomalies; performing *in-situ* evaluations; or are performing repairs, remediation, or maintenance. PHMSA does not expect operators to perform material properties verification for unknown pipe properties on pipeline segments exposed during one-call excavations. PHMSA has determined this approach is reasonable and will minimize the cost impacts of this final rule. A deadline for the material properties verification requirements of this rulemaking is not practical because it is impossible to forecast the rate or timing at which opportunities would arise to perform material properties verification for a given population of pipe.

Lastly, operators should have most of the required pipe information from following § 192.917(b) since subpart O of part 192 was codified over 15 years ago in 2003. Section 192.917(b) requires operators to identify and evaluate the potential threats to pipeline segments by gathering and integrating existing data and information on the entire pipeline that could be relevant to the pipeline segment. In performing this identification and evaluation, operators must follow the requirements in ASME/ANSI B31.8S, section 4, and at a minimum gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S. The material properties needed to establish and substantiate MAOP are included in these lists.

B. MAOP Reconfirmation - §§ 192.624 & 192.632

i. – Applicability

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to require operators reconfirm MAOP for the following three categories of pipeline:

1) Grandfathered pipe, in direct response to section 23(d) of the 2011 Pipeline Safety Act and NTSB recommendation P-11-14;
2) Pipe for which documentation is inadequate to support the MAOP, in direct response to section 23(c) of the 2011 Pipeline Safety Act; and

3) Pipe that has experienced a reportable in-service incident 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 spots, or stress corrosion cracking.

It is important to note that a given pipeline segment for which the MAOP reconfirmation process would apply might fit into one, two, or all three of these proposed categories. For pipeline segments where records of the pipeline physical properties and attributes to substantiate the current MAOP are not documented in traceable, verifiable, and complete records, only those segments located within an HCA or a Class 3 or Class 4 location would be subject to the MAOP reconfirmation process under the NPRM.

This proposal directly correlates to section 23 of the 2011 Pipeline Safety Act and NTSB recommendation P-11-14 regarding the need for spike hydrostatic testing where in-service incidents have occurred. The NTSB recommended such testing for all pipe manufactured before 1970.

For pipeline segments where operators established the MAOP in accordance with the grandfather clause at § 192.619(c) (i.e., pipeline segments where the MAOP is based upon the highest actual operating pressure records from a 5-year interval between July 1, 1965, to July 1, 1970, and where operators therefore do not have pressure test or material property records) or for segments with a history of in-service incidents caused by cracks or crack-like defects, PHMSA proposed to restrict the applicability of MAOP reconfirmation to HCAs, Class 3 or Class 4 locations, or MCAs, if the MCA segment can accommodate an ILI tool. The proposed inclusion of pipeline segments in these locations and with these traits slightly expand on the mandate contained in section 23 of the 2011 Pipeline Safety Act, which applied only to previously untested pipeline segments operating at a pressure greater than 30 percent SMYS located in an HCA.

In recommendation P-11-14, the NTSB recommended that all pipe manufactured before 1970 be subjected to a hydrostatic pressure test that would include a spike hydrostatic test, which PHMSA considered in its process for reconfirming MAOP. PHMSA's preliminary evaluation concluded that doing so may not be cost-effective, since a large amount of such pipe could be in remote locations where the likelihood of personal injury or property damage as a result of an incident would be low.

PHMSA's proposal expanded the applicability of MAOP reconfirmation beyond the minimum required by the congressional mandate to include pipe operating at less than 30 percent SMYS. In addition, the NPRM expanded the location criteria to include some non-HCA locations in the form of MCAs and Class 3 and Class 4 locations. As PHMSA proposed in the definitions section of the NPRM, MCAs are areas that, while not meeting the HCA criteria, include 5 or more persons or dwellings intended for human occupation or are otherwise locations where people congregate, including the right-of-ways of major roadways. See section H of this final rule for additional background on the MCA definition. The NPRM also specified that the MAOP reconfirmation process would apply only to MCA pipeline segments able to accommodate an ILI tool. This provision would not preclude an operator from choosing to conduct a pressure test, but it would avoid forcing operators to conduct a pressure test because the pipeline segment was not "piggable."

2. Summary of Public Comment

Many stakeholders provided input on the proposed provisions in § 192.624 that require MAOP reconfirmation for pipeline segments previously excluded from testing by the grandfather clause, pipeline segments without adequate documentation to substantiate the current MAOP, and pipeline segments that have experienced a reportable in-service incident.

Regarding the first criterion above, several commenters, including INGAA, AGA, and NAPSR, generally supported the provision requiring operators of pipeline segments where the MAOP was established via the grandfather clause to reconfirm the MAOP of those segments. Several of the pipeline industry trade associations and industry entities, however, did not support the proposed application of these criteria to all grandfathered pipeline segments within HCAs, Class 3 and Class 4 locations, and Class 1 and Class 2 piggable segments within MCAs. Gas Processors Association's Midstream Association (GPA) and AGA stated that while they support the congressional mandate to conduct testing to confirm the material strength of previously untested gas transmission pipelines in HCAs that operate at a pressure above 30 percent SMYS, they oppose the proposed provisions which extend to additional pipeline segments. INGAA and Washington Gas supported the applicability of MAOP reconfirmation in MCAs for pipelines operating at greater than or equal to 30 percent SMYS but disagreed with the proposed provisions that included MCA pipelines operating at less than 30 percent SMYS.

Some citizen groups, including PST, expressed concern that the proposed changes regarding the grandfather clause did not go far enough and suggested that PHMSA should fully implement the recommendations set forth by the NTSB. They stated that PHMSA should eliminate the grandfather clause given that the proposed provisions would not include the following groups of pipelines: (1) pipelines in non-HCA areas within Class 1 and Class 2 locations; and (2) pipeline segments for which there is an inadequate record of a hydrostatic pressure test in areas newly designated as an MCA that are not capable of being assessed by an in-line tool. Conversely, Northeast Gas Association (NGA) stated that PHMSA should retain the grandfather clause as it prevents existing, historically safe, and maintained pipelines from being subjected to unwarranted requirements.

For pipeline segments where operators do not have adequate documentation to support the current MAOP and that PHMSA proposed would be subject to the new MAOP reconfirmation requirements, some commenters stated that they support the requirement to the extent that it is consistent with the congressional mandate to reconfirm MAOP for pipeline segments with insufficient records within Class 3 and Class 4 locations and Class 1 and Class 2 HCAs. These commenters further stated that § 192.624(a)(2) within the proposed MAOP reconfirmation requirements should be revised to clarify that it applies only to those gas transmission pipeline segments in HCAs and Class 3 and Class 4 locations that were constructed and put into operation since the adoption of the Federal Pipeline Safety Regulations in 1970, stating that otherwise § 192.624(a)(2) would apply to those pipelines put into service prior to the implementation of Federal regulations where the requirement to maintain a pressure test record does not apply. Some commenters also stated that PHMSA should revise § 192.624(a) within the proposed MAOP reconfirmation requirements to make clear that operators that have used one of the proposed allowable methods for establishing MAOP in § 192.624(b) other than the pressure test method are not required to have a pressure test record to comply with the record requirements of the section. Washington Gas asserted that the MAOP reconfirmation requirements should apply to only pipeline segments in HCAs that operate at a pressure of greater than or equal to 30 percent SMYS. Other commenters, including Xcel Energy, stated that the proposed provisions should allow operator discretion regarding what constitutes a reliable, traceable, verifiable, and complete record to determine the necessary documentation to support a pressure test record and the necessary material properties for MAOP verification. Additionally, AGA recommended the deletion of the phrase "reliable, traceable, verifiable, and complete" from the proposed MAOP reconfirmation provisions in § 192.624(a)(2). Similarly, other commenters, including INGAA, recommended omitting "reliable" from the phrase and provided a suggested definition for "traceable, verifiable, and complete."

Lastly, with regard to the third category of applicable pipeline segments to the proposed MAOP reconfirmation requirements, many commenters either disagreed or requested clarification for the requirement that MAOP must be reconfirmed in cases where an in-service incident occurred due to a manufacturing defect listed under § 192.624(a)(1). For example, INGAA stated that an operator can evaluate such manufacturing defects more effectively through ongoing operations and maintenance activities rather than through MAOP reconfirmation, and that the defects PHMSA is concerned with are already addressed through integrity management. Similarly, Boardwalk Pipeline stated that pipelines that have experienced an in-service incident because of the listed defects in § 192.624(a)(1) should be subject to integrity management measures rather than MAOP reconfirmation. TransCanada and TPA recommended adding text to the applicability section of the MAOP reconfirmation requirements that would exclude a pipeline segment from such requirements if the operator has already acted to address the cause of the reported incident. Additionally, one commenter suggested that this requirement should apply only to pipelines in HCAs. Some commenters, including AGA and Consolidated Edison of New York (Con Ed), also requested additional time to comply with the proposed MAOP reconfirmation provisions, asserting that operators would be required to replace many of their transmission mains to comply with the new requirements because their current records would not be satisfactory. Due to the urban density and scale of the service areas of certain operators, AGA and Con Ed stated that this replacement process would take longer than the 15-year schedule provided in the rule. One commenter suggested that if the applicability criteria for pipeline segments with in-service incidents and manufacturing defects remains in the rule, it should be limited to a more contemporary time frame, such as a rolling 15-year window or those in-service incidents that have occurred since 2003. Pipeline Safety Trust, on the other hand, stated that the proposed timeframe of 15 years is too long for operators to reconfirm MAOP in HCAs and complete critical safety work, and they urged PHMSA to adopt significantly shorter timelines in the final rule.

Additionally, AGA asserted that the proposed MAOP provisions do not address how the completion plan and completion dates of the section would apply to pipelines that might experience a failure in the future and would then be subject to the proposed MAOP reconfirmation requirements, or for pipelines that are not currently located in a MCA but may be in the future. Lastly, INGAA stated that section 23 of the 2011 Pipeline Safety Act requires that PHMSA consult with the Chairman of the Federal Energy Regulatory Commission (FERC) and State regulators before establishing timeframes for the testing of previously untested pipes, and it is not evident that PHMSA has complied with this requirement.

As a general comment, several stakeholders, including AGA, Louisville Gas & Electric, New Mexico Gas Company, National Grid, NW Natural, PECO Energy, TECO Pipeline Gas, and New York State Electric and Gas (NYSEG), proposed an alternative method for MAOP reconfirmation where operators would execute two separate sets of actions that they stated could be performed simultaneously or separately. First, operators would either assess high-risk gas transmission pipelines using a pressure test or an alternative technology that is determined to be of equal effectiveness. Operators would categorize these pipelines in three tiers and schedule them for testing depending on the pipeline's SMYS and class location. Second, operators would use an ILI tool on all gas transmission pipelines, regardless of class location, that are capable of accommodating ILI tools. The ILI tool used would be qualified to find defects that would fail a subpart J pressure test. These commenters stated that this alternative methodology was necessary because the proposed provisions would create operational inefficiencies that would likely result in excessive cost and limited public benefit. In addition to providing this alternative proposal, many of these commenters provided other assorted comments on the proposed provisions.

At the GPAC meeting on March 26, 2018, the GPAC recommended that PHMSA revise the scope of the proposed MAOP reconfirmation provisions by excluding lines with previously reported incidents due to crack defects. To go along with this, the GPAC also recommended PHMSA create a new section in subpart O of part 192, the natural gas IM regulations, to address pipeline segments with crack-related incident histories. Doing these actions would eliminate the need for the proposed definitions of "modern pipe," "legacy pipe," and "legacy construction techniques," and the impact of this is discussed later in this document.

The GPAC also recommended that the MAOP reconfirmation provisions be revised to apply to pipeline segments in HCAs or Class 3 or Class 4 locations that do not have traceable, verifiable, and complete records necessary to establish MAOP under § 192.619. Previously, the provisions were applicable to those pipeline segments without traceable, verifiable, and complete subpart J pressure test records. Similarly, the GPAC recommended that the MAOP reconfirmation provisions only apply to grandfathered pipelines in HCAs, Class 3 or Class 4 locations, or MCAs able to accommodate inspection with ILI tools, and that have MAOPs producing a hoop stress greater than or equal to 30 percent SMYS. In the NPRM, the provisions applied to all grandfathered pipelines in those locations regardless of SMYS. In making this recommendation, the GPAC also suggested PHMSA review the costs and benefits of applying the MAOP reconfirmation provisions to non-HCA Class 3 and Class 4 grandfathered pipe with MAOPs less than 30 percent SMYS.

During the meeting on March 27, 2018, the GPAC also recommended revisions to other sections related to the applicability of MAOP reconfirmation provisions, including withdrawing the proposed revisions to § 192.503, which tied general requirements of the subpart J pressure test to alternative MAOP and MAOP reconfirmation provisions, and withdrawing the proposed revisions to § 192.605(b)(5), which cross-referenced several sections related to the MAOP reconfirmation requirements to the requirements regarding an operator's procedural manuals.

The GPAC also examined the provisions related to the completion date of these actions and recommended that PHMSA revise the appropriate paragraph to account for pipelines that may be subject to these requirements in the future, such as for pipelines that are not in an HCA or Class 3 or Class 4 location now, but due to population growth or development may be in such a location in the future. More specifically, the GPAC recommended that an operator would have to complete all actions required by the MAOP reconfirmation provisions on 100 percent of their pipelines that meet the applicability requirements by 15 years after the effective date of the rule or as soon as practicable but no later than 4 years after the pipeline segment first meets the applicability conditions, whichever is later. The GPAC also recommended PHMSA consider a waiver or no-objection procedure if operators cannot meet the requirements within 4 years under this scenario.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the applicability of MAOP reconfirmation. After considering these comments and as recommended by the GPAC input, PHMSA is modifying the rule to address many of these comments.

Regarding the applicability of the new MAOP reconfirmation requirements at § 192.624, PHMSA notes that a simplistic repeal of the "grandfather clause" at § 192.619(c) is not practical because it applies to gathering and distribution lines. As the proposed rule was primarily focused on the safety of gas transmission pipelines, a broad repeal of the grandfather clause was not contemplated in the proposed rule. Further, a major expansion of the MAOP reconfirmation requirements beyond the scope of the congressional mandate in the 2011 Pipeline Safety Act would be costly, and the GPAC noted at the meeting on March 26, 2018, that there may be cost-benefit concerns to test all grandfathered pipelines. The GPAC recommended PHMSA analyze requiring operators to reconfirm the MAOP of all grandfathered lines, and PHMSA considered this as an alternative in the RIA.[65]

In response to the comments received and the recommendations of the GPAC, PHMSA is modifying the applicability of the MAOP reconfirmation requirements as follows: (1) The applicability related to pipeline segments with past in-service incidents is being eliminated. As commenters mentioned, operational failures are already addressed within integrity management and other subparts of part 192. Section 192.617, for example, would require an operator of a gas transmission line that had an in-service incident caused by an incorrect MAOP to determine the proper MAOP of the segment before placing it back into service. Causes of in-service failures are also already incorporated into the risk analyses required by the current IM regulations. If the

[65] See section 5.9.1 of the RIA for further details.

cause of an incident is an incorrect MAOP, for example, then operators would be required to reconfirm it following the incident within their IM program. However, PHMSA is adding a new paragraph to strengthen the IM requirements at § 192.917(e)(6) to specifically include actions operators must take to address pipeline segments susceptible to cracks and crack-like defects. (2) PHMSA is also modifying the applicability of these requirements by specifying the MAOP reconfirmation requirements are applicable to pipeline segments that do not have the pipeline physical properties and attributes needed to establish MAOP documented in traceable, verifiable, and complete records, specifically those records required to establish and substantiate the MAOP in accordance with § 192.619(a), including those records required under § 192.517(a). More specifically, these requirements to verify MAOP would apply to such pipelines without traceable, verifiable, and complete records in HCAs and Class 3 and Class 4 locations as specified in the congressional mandate. Further, PHMSA is dropping the word "reliable" from the applicability section of the regulatory text to be consistent with previous PHMSA advisory bulletins on this topic.[66] (3) PHMSA is modifying the applicability of the MAOP reconfirmation provisions for "grandfathered" pipeline segments to pipelines with an MAOP greater than or equal to 30 percent of SMYS, as specified in the congressional mandate. In addition to these requirements applying to grandfathered pipelines in HCAs, PHMSA is retaining the MAOP reconfirmation applicability requirement for grandfathered pipeline segments in Class 3 and Class 4 locations and in piggable MCAs to address the NTSB recommendation on this topic. As per the committee's suggestion, PHMSA analyzed whether it would be feasible to make the MAOP reconfirmation requirements applicable to non-HCA Class 3 and Class 4 pipe operating below 30 percent SMYS. This analysis is presented as an alternative in the RIA for this

[66] Pipeline Safety: Verification of Records; 77 FR 26822; May 7, 2012; https://www.govinfo.gov/content/FR-2012-05-07/pdf/2012-10866.pdf

rulemaking. Ultimately, PHMSA did not choose to include these categories of pipelines in the scope for the applicability of the MAOP reconfirmation requirements because the GPAC recommended it was cost-effective for the provision to only apply to pipe operating above 30 percent SMYS in Class 3 and 4 locations and because those pipelines present the greatest risk to safety.

With respect to the completion date, PHMSA acknowledges the comments received stating that pipeline segments could meet applicability criteria at some point in the future such that it would be difficult or impossible to meet the 15-year deadline for completion. Therefore, PHMSA agrees with the GPAC recommendation discussed above and is modifying the requirements in this final rule to include an alternative completion deadline of 4 years for pipeline segments that meet the applicability standards at some point in the future, for example for those pipeline segments that were in non-HCA locations that later become HCA locations. However, PHMSA emphasizes that this 4-year timeframe does not supersede, invalidate, or otherwise modify the existing requirements in § 192.611 for operators to confirm or revise the MAOP of segments within 24 months of a change in class location.

PHMSA also acknowledges that some commenters thought the 15-year compliance timeframe for MAOP reconfirmation was too long. PHMSA believes a 15-year timeframe is necessary to be consistent with § 192.939, which allows operators to use a confirmatory direct assessment to confirm their MAOP in two, 7-year inspection cycles. This timeframe was discussed by the GPAC and was approved by unanimous vote. PHMSA will note that operators are required to have 50 percent of the applicable mileage completed within 8 years of the effective date of the rule. PHMSA would expect operators to prioritize and reconfirm the MAOP of the highest-risk segments first.

PHMSA is also withdrawing miscellaneous revisions to § 192.503, which tied general requirements of the subpart J pressure test to alternative MAOP and MAOP reconfirmation provisions, and miscellaneous revisions from § 192.605(b)(5), which cross-referenced several sections related to MAOP requirements to the requirements regarding an operator's procedural manuals. These changes were made to simplify the regulations.

Additionally, because PHMSA has eliminated pipeline segments with past in-service incident history from the scope of the MAOP reconfirmation requirements, PHMSA is striking the proposed references within the MAOP reconfirmation requirements to the alternative MAOP requirements at § 192.620(a)(ii). Operators who used the alternative requirements to establish the MAOP of their pipelines were required to have complete documentation[67] and therefore would not be subject to the MAOP reconfirmation requirements. If an operator had previously established the MAOP of a pipeline segment under the alternative MAOP requirements, but has since lost the records necessary to validate the alternative, they would have to reconfirm MAOP using the alternative MAOP requirements, or apply for a special permit to continue operation.

Per the requirement in section 23 of the 2011 Pipeline Safety Act, PHMSA consulted with members of FERC and State regulators, including representatives from NAPSR and the National Association of Regulatory Utility Commissioners, as appropriate, to establish the timeframes for completing MAOP reconfirmation. As a part of this consultation, which occurred as a function of the GPAC meetings from 2017 through 2018, PHMSA accounted for potential consequences to public safety and the environment while also accounting for minimal costs and service disruptions. These representatives provided both input and positive votes that the provisions surrounding MAOP reconfirmation were technically feasible, reasonable, cost-

[67] "Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines; Final Rule;" October 17, 2008; 73 FR 62148. The effective date of the rule was November 17, 2008.

effective, and practicable if certain changes were made. As previously discussed, PHMSA has taken the GPAC's input into consideration when drafting this final rule and made the according changes to the provisions.

B. MAOP Reconfirmation - §§ 192.624 & 192.632

ii. – Methods

In developing regulations to reconfirm MAOP where necessary, Congress mandated that PHMSA consider safety testing methodologies that include pressure testing and other alternative methods, including in-line inspections, determined to be of equal or greater effectiveness. The NTSB recommended an expansive pressure test approach to address the safety issues identified in their investigation of the PG&E incident through recommendations P-11-14 and P-11-15. In response to the congressional mandate, PHMSA evaluated other methodologies and identified five additional methods that could provide an equivalent or greater level of safety. Therefore, PHMSA proposed to allow the following six methods for MAOP reconfirmation, including the conventional pressure test method.

Summary of PHMSA's Proposal: Method 1 – Pressure Test

A pressure test is the most conventional assessment method by which an operator may reconfirm a pipeline segment's MAOP. PHMSA proposed standards for conducting pressure tests for MAOP reconfirmation in part to meet the intent of NTSB recommendations P-11-14 and P-11-15. First, PHMSA proposed minimum test pressure standards where a pipeline segment's MAOP would be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor. Second, if the pipeline segment might be susceptible to cracks or crack-like defects,[68] then the operator must incorporate a spike pressure feature into the pressure test procedure. PHMSA proposed standards for the spike hydrostatic test in § 192.506. If the operator has reason to believe any pipeline segment may be susceptible to cracks or crack-like defects, the operator would be required to also estimate the remaining life of the pipeline in accordance with the same standards specified in Method 3, the engineering critical assessment method.

Summary of Public Comment: Method 1 – Pressure Test

Several commenters opposed the proposed provisions requiring a spike test to be conducted as part of the pressure test for the purposes of MAOP reconfirmation, and these comments are discussed further under the "spike test" portion of the proposal and comment summary of this rulemaking.

API suggested that a pipeline segment's MAOP can be best established through performing a combination of pressure tests and ILI examinations, and they discussed how operators could conduct hydrostatic pressure testing to determine the in-place yield strength of a segment of pipeline by conducting a "spike" test pressure held for a few minutes followed by a subpart J pressure test approximately 10 percent below the spike level. API further stated that using ILI tools in conjunction with this method would further substantiate the results, as geometry ILI tools capable of measuring inside diameter to detect yielding could further substantiate and quantify the results of the pressure test.

AGA stated that while they believe that pressure testing is a straightforward and well-established method, the proposed Method 1 MAOP reconfirmation requirements are

[68] These pipelines can include pipelines constructed with "legacy pipe" or using "legacy construction techniques;" pipelines with evidence or risk of stress corrosion cracking or girth weld cracks; or pipelines that have experienced an incident due to an original manufacturing-related defects, construction-related defects, installation-related defects, or fabrication-related defects.

unnecessarily complex. AGA further stated that subpart J provides different requirements and specifications for pressure tests based on the type of pipe being tested, and that Method 1 should refer to subpart J rather than to § 192.505(c) specifically, which requires unnecessarily stringent requirements. PG&E supported the proposed provisions and committed to pressure testing all pipes.

INGAA stated that since the basic strength properties of steel pipe do not change over time, PHMSA should not limit allowable tests to only those conducted after July 1, 1965, as was proposed in § 192.619(a)(2)(ii). They emphasized that the test parameters, not the test date, should be considered for MAOP reconfirmation. Further, INGAA stated that recognizing the validity of earlier tests would not necessarily mean that no further pressure tests would be conducted, as periodic testing may be required to ensure the continued integrity of the pipeline segment under the operator's integrity management program. However, such additional tests are managed under IM, which is separate from MAOP reconfirmation.

Certain commenters stated that a spike test is not required to establish an adequate margin of safety for MAOP reconfirmation and suggested PHMSA eliminate spike testing from the pressure test method of MAOP reconfirmation.

Regarding the proposed definitions of "legacy pipe" and "legacy construction," AGA and Xcel Energy commented that as proposed, the definitions could be interpreted to apply to distribution pipelines as well as gas transmission pipelines. Commenters requested that PHMSA explicitly exclude distribution pipelines from these definitions, which would be applicable to all part 192.

On March 26, 2018, the GPAC recommended that PHMSA delete the spike test requirements from the pressure test method of MAOP reconfirmation. The GPAC also recommended that PHMSA require operators to perform a pressure test in accordance with subpart J of part 192 rather than refer to specific requirements in § 192.505. Further, and as discussed during the meetings of December 2017 and March 26, 2018, if the applicable pressure test segment does not have traceable, verifiable, and complete MAOP records, the operator must use the best available information upon which the MAOP is currently based to conduct the pressure test. The GPAC recommended PHMSA create a requirement for the operator of such a pipeline segment to add the test segment to its plan for opportunistically verifying material properties in accordance with the material properties verification provisions. During the meeting, PHMSA noted that most pressure tests would present at least two opportunities for material properties verification at the test manifolds.

PHMSA Response: Method 1 – Pressure Test

PHMSA appreciates the information provided by the commenters regarding the pressure test method of MAOP reconfirmation (Method 1). After considering these comments and as recommended by the GPAC, PHMSA is eliminating the spike testing requirement as part of the pressure test method of MAOP reconfirmation. As commenters stated, spike testing is primarily used for the mitigation of cracks and crack-like defects, and PHMSA has determined it would therefore be more appropriate to be placed within the context of threat management under IM. Additionally, PHMSA is removing the definitions for and related references to “legacy pipe” and “legacy construction” in this final rule because the applicability to pipe with “legacy pipe or construction” leaks or failures was dropped from the applicability criteria for MAOP reconfirmation. PHMSA also modified the rule to refer to subpart J pressure tests rather than paragraph § 192.505(c), specifically, and to recognize the validity of earlier pressure tests.

Lastly, if an operator does not have traceable, verifiable, and complete records for the material properties needed to establish MAOP by pressure testing, PHMSA is requiring that operators test, in accordance with the material verification requirements, the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. Further, if there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with the material properties verification requirements to ensure that the segment of pipe is consistent with operator's sampling program established under § 192.607. This will avoid issues where operators may not have the documented and verified physical pipeline material properties and attributes that would otherwise be necessary to perform a hydrostatic pressure test to reconfirm MAOP.

Summary of Proposal: Method 2 – Pressure Reduction

In the NPRM, PHMSA proposed that pipeline operators could choose to reduce the MAOP of the applicable pipeline segment to reconfirm the segment's MAOP. This approach would use the recent operating pressure as a *de facto* pressure test, and then an operator would set the pipeline segment's MAOP at a slightly lower pressure. PHMSA proposed that operators using this method set the pipeline's MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 18 months preceding the effective date of the final rule divided by the greater of either 1.25 or the applicable class location, which are the same safety factors as used for the pressure testing in Method 1. PHMSA included standards for establishing the highest actual sustained pressure for the purposes of reconfirming MAOP under this method and included standards for addressing class location changes. Additionally, PHMSA proposed that, if the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects, the operator would be required to estimate the remaining life of the pipeline.

Summary of Public Comment: Method 2 – Pressure Reduction

AGA commented that the 18-month look-back time frame listed in the pressure reduction MAOP reconfirmation method is a much too narrow time frame for consideration and that the section should be rewritten to clarify that the pressure reduction should be taken from either (1) the immediate past 18 months, or (2) 5 years from the time the last pressure reduction was taken, stating that tying the baseline pressure to the effective date of the rule is arbitrary. Enterprise Products recommended that PHMSA clarify the derating criteria used for pipes that use this method of reconfirming MAOP. Further, Piedmont expressed concern that this method does not account for the actual gap that can occur between MAOP and operating pressure. Some commenters questioned whether the MAOP from which to take a pressure reduction was based on the most recent pressure test or the historical highest-pressure test, and some commenters suggested PHMSA revise this provision to allow operators to reconfirm the MAOP based on the existing MAOP and not using an 18-month look-back period unless an incident caused by a material-related or construction-related defect has occurred on the pipeline since its last subpart J pressure test.

TPA stated that using this method unfairly penalizes operators in situations where the operator has prepared for future needs and has not operated at MAOP for a period greater than 18 months. Similarly, another commenter suggested that operators who have already reduced MAOP on pipeline segments to be proactive should not be penalized by having to take an additional reduction in MAOP.

Some commenters recommended limiting the applicability of this method to those pipelines operating at 30 percent SMYS or greater.

Regarding the pressure reduction method for MAOP reconfirmation, the GPAC recommended PHMSA increase the look-back period from 18 months to 5 years and remove the requirements for operators selecting to take the pressure reduction to reconfirm MAOP to perform fracture mechanics analysis on those pipeline segments.

PHMSA Response: Method 2 – Pressure Reduction

PHMSA appreciates the information provided by the commenters regarding the pressure reduction method of MAOP reconfirmation (Method 2). After considering these comments and as recommended by the GPAC, PHMSA is increasing the look-back period to 5 years from the publication date of the rule and is removing the requirements for operators to perform fracture mechanics analysis on those pipeline segments where the operator has selected Method 2. PHMSA made this change because the 5-year look-back period is consistent with IM requirements regarding MAOP confirmation.

Summary of PHMSA's Proposal: Method 3 – Engineering Critical Assessment

Method 3 directly addresses the congressional mandate for PHMSA to consider safety testing methodologies that include other alternative methods, including ILI, determined to be of equal or greater effectiveness. Demonstrating that knowledge gained from an ILI assessment provides an equivalent level of safety as a pressure test is technically challenging. PHMSA used best safety practices gained from implementation of integrity management since 2003; development of class location special permits; and technical research on related topics, such as analysis of crack defects and seam defects. PHMSA applied these principles and analytical methods to develop an engineering critical assessment (ECA) methodology, which applies state-of-the-art fracture mechanics analysis to analyze defects in the pipe and determine if those defects would or would not survive a hydrostatic pressure test at the test pressure needed to establish MAOP. In addition, PHMSA proposed that if the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects, the operator would be required to estimate the remaining life of the pipeline using the fracture mechanics standards PHMSA specified.

Summary of Public Comment: Method 3 – Engineering Critical Assessment

Several trade associations and pipeline industry entities stated that ILI is the best and most practical method for MAOP reconfirmation due to its cost-effectiveness and environmentally friendly nature, and that PHMSA should allow operators to use ILI as a reconfirmation method. These commenters, however, also stated that the requirements proposed for the usage of ILI with an ECA are overly complicated and burdensome, and they specifically recommended that the final rule should be simplified so that this method will play a greater role in MAOP reconfirmation in lieu of a pressure test. For example, INGAA asserted that PHMSA should remove the requirements in the ECA related to operations, maintenance, and integrity management, arguing that these requirements do not factor into MAOP reconfirmation and would be covered elsewhere in part 192. Further, INGAA proposed additional alternatives for using the ECA method to obtain necessary data for MAOP reconfirmation, asserting that these alternatives would be less burdensome and equally effective. More specifically, INGAA suggested removing duplicate regulatory language, removing the pre-approval process for ILI, and adding unity plots as a method for operators to demonstrate that ILI is reliable for identifying and sizing actionable anomalies. TransCanada and PECO Energy Co. stated that for the ECA method to be used by industry, the detailed requirements listed under this method in the proposed rule should be replaced with the use of standard ECA best practices.

Some commenters suggested that operators have long relied on sound engineering judgments and conservative assumptions to account for record gaps. Commenters stated that, if stripped of the ability to use sound engineering judgment and conservative assumptions, operators would need to substantially invest in processes, procedures, tests, and project engineering and support to develop and implement a comprehensive material properties verification plan as outlined in the proposed regulations. Another commenter asked for clarification on using assumptions of Grade A pipe (30,000 psi) versus the use of 24,000 psi as noted in § 192.107(b)(2) if the SMYS or actual material yield strength and ultimate tensile strength is unknown or is not documented in traceable, verifiable, and complete records.

Another commenter suggested that in cases where a pipeline has been pressure tested, but not to the level of 1.25 times MAOP, PHMSA should allow operators to augment the original test with an ECA and other analysis to reconfirm the pipeline segment's MAOP under method 3.

The PST stated that there are certain cases in which the ECA method should not be allowed as an alternative to pressure testing. Citing a white paper prepared by Accufacts, Inc. on ECA methodology, the PST recommended that PHMSA prohibit the use of the ECA method for determining the strength of a pipeline segment in cases where there are girth weld crack threats, significant stress corrosion cracking threats, or dents with stress concentrator threats.

During the GPAC meeting on March 27, 2018, the GPAC recommended that PHMSA remove the fracture mechanics analysis for failure stress and crack growth analysis requirements from the ECA method of MAOP reconfirmation and move them to a stand-alone section in the regulations. Further, the GPAC recommended that such a section should not specify when, or for which pipeline segments, fracture mechanics analysis would be required. The GPAC suggested that this new fracture mechanics section outline a procedure by which operators perform fracture mechanics analysis when required or allowed by other sections of part 192, which was similar to its treatment of the proposed material properties verification procedures at § 192.607. Under the GPAC's proposal, the ECA method for MAOP reconfirmation would not contain any specific technical fracture mechanics requirements or Charpy V-notch toughness values but would instead refer to the new fracture mechanics section. Other recommendations related specifically to the new fracture mechanics section are discussed in that area of the proposal and comment summary section of this document.

The GPAC also recommended PHMSA add a requirement to verify material properties in accordance with the rule's material properties verification provisions if the information needed to conduct a successful ECA is not documented in traceable, verifiable, and complete records.

PHMSA Response: Method 3 – Engineering Critical Assessment

PHMSA appreciates the information provided by the commenters regarding the ECA method of MAOP reconfirmation (Method 3). As recommended by the GPAC, PHMSA is removing the fracture mechanics analysis requirements from the ECA method of MAOP reconfirmation and moving them to a new stand-alone § 192.712. PHMSA agrees this change will improve comprehension of the regulations. This new section does not specify when, or for which pipeline segments, fracture mechanics analysis would be required but instead outlines a procedure by which operators perform fracture mechanics analysis when required by other sections of part 192. Section 192.712 is referenced in the pressure reduction, ECA, and "other technology" methods of MAOP reconfirmation under § 192.624, as well as in § 192.917 for cyclic fatigue loading. Therefore, the ECA method for MAOP reconfirmation does not contain any specific technical fracture mechanics requirements or Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) but instead refers to the new § 192.712. Comments related to the assumptions an operator can use when material properties are unknown are addressed in the discussion on § 192.712 below. PHMSA also added a requirement to verify material properties in accordance with the rule's material properties verification provisions at § 192.607 if the information needed to conduct a successful ECA is not documented in traceable, verifiable, and complete records.

PHMSA disagrees that the additional analytical requirements, beyond ILI, are overly complicated or burdensome. To conclude that an ECA is of equal or greater effectiveness as a pressure test for the purposes of MAOP reconfirmation, as mandated by Congress, more than an ILI and repair program is required. A pressure test proves that any flaws in the pipe are small enough to hold the test pressure without leaking. Such subcritical flaws must be analyzed to prove that they would pass a pressure test, even if the pressure test is not conducted. A fracture mechanics analysis is capable of reliably drawing such conclusions but must be carefully and capably performed. Such an analysis also requires accurate data. In the absence of reliable data for key parameters, such as fracture toughness, PHMSA allows the use of appropriately conservative assumptions. This is discussed in more detail in the sections below.

Based on an ASME report and research sponsored by PHMSA,[69] the ECA analysis can be reliably used to ascertain if a pipeline segment would pass a pressure test, even if it has seam weld cracking, and the final rule includes requirements for conducting ILI using tools capable of detecting girth weld cracks. 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.

PHMSA also notes that the final rule addresses cases where a pipeline has been pressure tested, but not to the level of 1.25 times MAOP, by allowing operators to account for those test results and augment the original test with an ECA, or conduct an ILI tool assessment program to characterize defects remaining in the pipe along with using an ECA to establish MAOP, to reconfirm the pipeline segment's MAOP using Method 3. Detailed ILI requirements are addressed in new § 192.493, which is discussed in more detail below.

PHMSA is moving the ECA process requirements in this final rule to a new stand-alone § 192.632. Section 192.624(c)(3) (ECA method of MAOP reconfirmation) and the new § 192.632 will cross-reference each other. PHMSA decided to make this change when finalizing this rulemaking only to improve the readability of the regulations. No substantive changes were made to the requirements in connection with this organizational change.

Summary of PHMSA's Proposal: Method 4 – Pipe Replacement

When reconfirming MAOP on certain pipeline segments, some operators may face significant technical challenges or costs when performing either a pressure test or an ILI

[69] See: American Society of Mechanical Engineers (ASME) Standards Technology Report "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas" (STP-PT-011), and ''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1'' (Task 4.5); https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390

examination, and it may be more economically viable to replace the pipeline. Therefore, PHMSA proposed to allow pipe replacement for operators to reconfirm their MAOP. In such cases, the replacement pipeline would be designed, constructed, and pressure tested according to current standards to establish MAOP.

Summary of Public Comment: Method 4 –Pipe Replacement

Commenters, including Mid-American Energy Company and Paiute Pipeline, stated their support for this method. The GPAC similarly supported this method and did not recommend any changes for this aspect of MAOP reconfirmation.

PHMSA Response: Method 4 – Pipe Replacement

PHMSA appreciates the information provided by the commenters regarding the pipe replacement method of MAOP reconfirmation (Method 4). After considering these comments and as recommended by the GPAC, PHMSA is retaining the proposed rule text for Method 4 in the final rule.

Summary of PHMSA's Proposal: Method 5 – Pressure Reduction for Small, Low-Pressure Pipelines

For low-pressure, smaller-diameter pipeline segments with small potential impact radii (PIR), PHMSA proposed an MAOP reconfirmation method similar to the pressure reduction under Method 2. Operators of pipeline segments for which 1) the MAOP is less than 30 percent SMYS, 2) the PIR is less than or equal to 150 feet, 3) the nominal diameter is equal to or less than 8 inches,[70] and 4) which cannot be assessed using ILI or a pressure test, may reconfirm the MAOP as the highest actual operating pressure sustained by the pipeline segment 18 months preceding the effective date of the final rule, divided by 1.1. In addition to this pressure reduction, operators of these lines would be required to perform external corrosion direct assessments in accordance with the IM provisions, develop and implement procedures to evaluate and mitigate any cracking defects, conduct a specified number of line patrols at certain intervals, conduct periodic leak surveys, and odorize the gas transported in the pipeline segment.

Summary of Public Comment: Method 5 – Pressure Reduction for Small, Low-Pressure Pipelines

AGA stated that PHMSA did not provide enough justification for imposing the additional pressure reduction requirements listed under this method, asserting that this method should require either a 10 percent pressure reduction or the implementation of additional preventative actions that are feasible and practical, but not both. TPA stated that the 18-month criterion penalizes operators who may have operated pipelines at lower capacities to anticipate future needs. Furthermore, TPA urged PHMSA to limit the requirements for MAOP reconfirmation under Method 5 to the reduction in MAOP and not impose additional safety requirements, stating that these pipelines are generally considered low-stress pipelines and that their risk of rupture is very low. Similarly, API stated that the proposed requirements for odorization and frequent instrumented leak surveys are impractical. Some commenters felt that the terms for small potential impact radius and the applicable diameters should be defined.

[70] 8.625 inches actual diameter

On March 27, 2018, the GPAC recommended PHMSA delete the size and pressure criteria of this method and base the applicability solely on a potential impact radius of less than or equal to 150 feet. The GPAC also recommended increasing the look-back period to 5 years from 18 months. Further, the GPAC recommended PHMSA strike the additional requirements in this method related to external corrosion direct assessment, crack analysis, gas odorization, and fracture mechanics analysis. They also recommended PHMSA change the frequency of patrols and surveys to 4 times a year for Class 1 and Class 2 locations, and 6 times per year for Class 3 and Class 4 locations.

PHMSA Response: Method 5 – Pressure Reduction for Small, Low-Pressure Pipelines

PHMSA appreciates the information provided by the commenters regarding the pressure reduction method of MAOP reconfirmation for small, low-pressure pipelines (Method 5). After considering these comments and as recommended by the GPAC, PHMSA is deleting the pipeline segment size and pressure criteria of this method and basing the applicability solely on a potential impact radius of less than or equal to 150 feet. PHMSA believes this change streamlines the regulations while maintaining pipeline safety. PHMSA is increasing the look-back period to 5 years, which is consistent with other sections of part 192, including integrity management. Additionally, PHMSA is deleting the requirements in this method related to external corrosion direct assessment, crack analysis, gas odorization, and fracture mechanics analysis. PHMSA is also changing the frequency of patrols and surveys to 4 times a year for Class 1 and Class 2 locations, and 6 times per year for Class 3 and Class 4 locations. PHMSA believes these changes increase regulatory flexibility while maintaining pipeline safety.

Summary of Proposal: Method 6 – Alternative Technology

PHMSA proposed that operators may use an alternative technical evaluation process that provides a documented engineering analysis for the purposes of MAOP reconfirmation. If an operator elects to use an alternative method for MAOP reconfirmation, it would have to notify PHMSA and provide a detailed fracture mechanics analysis – including the safety factors – to justify the establishment of the MAOP using the proposed alternative method. The notification would have to demonstrate that the proposed alternative method would provide an equivalent or greater level of safety than a pressure test. PHMSA included this option to allow and encourage the continual research and development needed to improve state-of-the-art fracture mechanics analysis, integrity assessment methods, advances in metallurgical engineering, and new techniques.

Summary of Public Comment: Method 6 – Alternative Technology

For the alternative technologies method of MAOP reconfirmation, several stakeholders opposed the timeframes, case-by-case approval process, and procedural barriers PHMSA proposed for using this method. Several commenters, including Cheniere Energy, Delmarva Power & Light, and INGAA, suggested that the procedural hurdles required by the proposed provisions would make this option difficult for operators to use for MAOP reconfirmation as well as for any other provisions PHMSA allows alternative technology use with notification. More specifically, these commenters suggested that a process whereby PHMSA could object to the use of an alternative technology at any time during a project's lifecycle does not provide the level of certainty necessary for operators to move forward with using alternative technologies. That uncertainty would deter the development of what could be better or safer alternatives.

Piedmont stated that it does not believe that the role of PHMSA includes determining the appropriate technologies to be used to reconfirm MAOP. Piedmont further stated that currently under subpart O, operators are required to obtain approval from PHMSA to use alternative technologies for integrity assessment, and that operators have waited more than 180 days for PHMSA to respond to these requests. Piedmont stated that this uncertainty cannot be reconciled with the planning and business considerations that an operator must consider when evaluating how to invest in technology and which methods to use for establishing MAOP. The PST stated that the approval process should be similar to the process used for special permits and that before these methods are approved by PHMSA, they should be subject to public review and comment under the National Environmental Policy Act of 1969 (NEPA).

At the meeting on March 27, 2018, the GPAC recommended PHMSA incorporate the 90-day notification and objection procedure for the use of alternative technology. To summarize, operators would have to notify PHMSA of its intent to use other technology, and PHMSA would have 90 days to respond with an objection if PHMSA had one, or a need for more review time. Otherwise, the operator would be free to use the proposed method or technology.

PHMSA Response: Method 6 – Alternative Technology

PHMSA appreciates the information provided by the commenters regarding the other technology method of MAOP reconfirmation (Method 6). After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to incorporate the 90-day notification and objection procedure the committee recommended. Operators would have to notify PHMSA of its intent to use other technology to reconfirm MAOP in accordance with § 192.18, and PHMSA would have 90 days to respond with an objection if PHMSA had one or a notice that PHMSA required more time for its review, which would extend the timeframe. Without a notice of objection or additional review by PHMSA, the operator would be allowed to use the alternative technology. PHMSA has successfully applied the notification process to other technology assessments under subpart O since its inception and does not believe a special permit process is warranted for every notification for alternative technology. PHMSA believes the changes made in the final rule will address the concerns about timeliness of notification reviews by PHMSA.

B. MAOP Reconfirmation - § 192.624

iii. – Spike Test

1. Summary of PHMSA's Proposal

The "spike" hydrostatic pressure test is a special feature of the pressure testing method of MAOP reconfirmation. PHMSA intends this aspect of the MAOP reconfirmation process to address the intent of NTSB recommendations P-11-14 (related to spike testing for grandfathered pipe) and P-11-15 (related to pressure testing to show that manufacturing and construction-related defects are stable).

PHMSA proposed that a spike test would be required for cases where a pipeline segment might be susceptible to cracks or crack-like defects. Such pipe may include "legacy pipe;" pipe constructed using "legacy" construction techniques; pipelines that have experienced an incident due to an original manufacturing-related defect, a construction-, installation-, or fabrication-related defect; or pipe with stress corrosion cracking or girth weld cracks. Cracks and crack-like defects in some cases may be susceptible to a phenomenon called "pressure reversal," which is the failure of a defect at a pressure less than a pressure level that the flaw has previously experienced and survived. The increased stress from the test pressure may cause latent cracks that are almost, but not quite, large enough to fail to grow during the test. If the crack does not fail before the test is completed, the resultant crack that remains in the pipe may be large enough to no longer be able to pass another pressure test. The spike portion of the pressure test is designed to cause such marginal crack defects to fail during the early, spike phase of the pressure test. The post-spike, long-duration test pressure validates the operational strength of the pipe. Using a short-duration, very high spike pressure followed by a long-duration integrity verification pressure provides greater assurance that the test is not "growing cracks" that could fail in-service after the test is completed. PHMSA proposed standards for the spike hydrostatic test in § 192.506. PHMSA used several technical reports and studies, including PHMSA-sponsored research, to inform the standards proposed for the spike test. Those materials include, American Society of Mechanical Engineers Standards Technology Report "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas" (STP-PT-011), and ''Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase 1'' (Task 4.5).[71]

2. Summary of Public Comment

Some commenters supported the concept of requiring the use of a spike hydrostatic pressure test as part of the MAOP reconfirmation process for establishing MAOP but expressed concern over specific aspects of the provision. For example, AGA urged PHMSA to allow pneumatic pressure tests as well as hydrostatic pressure tests. In addition, AGA disagreed with the allotted test duration provided in the proposal. Similarly, other operators who commented,

[71] https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390

such as CenterPoint Energy and Dominion East Ohio, stated that the proposed spike test target hold pressure of 30 minutes exceeds the time needed to determine the mechanical integrity of the pipeline test segment and will cause pre-existing crack-like defects to grow. Alternatively, Dominion Transmission, Tallgrass Energy Partners, SoCalGas, and Paiute Pipelines stated that a test level of 100 percent SMYS, not 105 percent SMYS, would be sufficient to remediate cracking threats. Enterprise Products stated that the requirements for the design of a spike test should be based on integrity science, such as fatigue life and reassessment intervals, and suggested PHMSA's proposed spike test pressure limits were set at an arbitrary level. Enterprise further stated that the utility of stressing a pipe beyond 100 percent of its yield strength is questionable and potentially damages the pipe. Other commenters, including MidAmerican Energy Co., requested that pneumatic spike tests to 1.5 times MAOP be allowed when the resultant pressure complies with the limitations stated in the table in § 192.503(c).

Trade associations and pipeline industry entities, including INGAA, GPA, and TPA, asserted that PHMSA should eliminate the spike test requirement for establishing MAOP entirely. These commenters stated that the proposed provisions went beyond what was required to reconfirm MAOP for an accepted margin of safety. These commenters further asserted that spike testing is not an appropriate technique for MAOP reconfirmation, and it could result in unintended negative consequences without improving pipeline safety. They stated that spike testing is an aggressive and destructive technique that should be used only in cases in which time-dependent threats, such as a significant risk of stress corrosion cracking, exist.

INGAA and other commenters agreed with PHMSA that the use of spike hydrostatic testing is appropriate for time-dependent threats, such as stress corrosion cracking. INGAA, however, suggested changes to the proposed spike hydrostatic pressure test provisions and the cross-reference to those provisions in the proposed IM assessment method revisions to limit the spike testing requirement to time-dependent threats, to test to a minimum of 100 percent SMYS instead of 105 percent, and to provide an alternative for use of an instrumented leak survey. INGAA agreed that spike testing is the best means of testing a pipeline with a history of environmental cracking, such as stress corrosion cracking that has developed while a pipeline is in service, and noted that a spike test may be of value for in-service pipelines where metallurgical fatigue is of concern. INGAA further stated that pressure cycling should not need to be included in the proposed spike test provisions and that PHMSA should amend the proposed rule to limit spike testing only to those pipeline segments with stress corrosion cracking.

An additional commenter suggested PHMSA should allow operators to use the short-duration spike portion of a spike pressure test to determine the lower bound of the yield strength of the test section, including all pipe and components that are subjected to the test pressure. Such a test, if used for this purpose, must also confirm that yielding beyond that experienced in a standard tensile test to determine yield strength, typically on the order of 0.5 percent, has not occurred. This confirmation may be demonstrated by data from a pressure-volume plot of the test or a post-test geometry tool in-line inspection.

Public interest and other groups, including Pipeline Safety Coalition, Environmental Defense Fund (EDF), and NAPSR, expressed support for spike testing, stating that it would provide for increased pipeline safety. NAPSR further stated that the option of applying to use alternative technology or an alternative technological evaluation process would allow for some flexibility in cases in which a hydrostatic test is impractical. EDF also suggested additional measures to mitigate emissions from methane gas lost during testing.

At the GPAC meeting on March 2, 2018, the GPAC recommended that PHMSA revise the spike test requirements to change the minimum spike pressure to the lesser of 100 percent SMYS or 1.5 times MAOP, reduce the spike hold time to a minimum of 15 minutes after the spike pressure stabilizes, revise the applicable language to refer specifically to "time-dependent" cracking, incorporate the 90-day notification and objection procedure discussed for other sections, and adjust the SME requirements by adding language describing a "qualified technical subject matter expert" where applicable.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the requirements for spike pressure testing. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to change the minimum spike pressure to the lesser of 100 percent SMYS or 1.5 times MAOP, as PHMSA believes these pressures are sufficient to maintain pipeline safety. PHMSA is specifying a spike hold time of a minimum of 15 minutes after the spike pressure stabilizes, rather than a 30-minute overall hold time, to be consistent with pipeline safety. Additionally, PHMSA is modifying the rule to revise the applicable language to refer specifically to "time-dependent" cracking, incorporate the same notification procedure under § 192.18 with the 90-day timeframe for objections or requests for more review time, and adjust the SME requirements by using broader language describing a "qualified technical subject matter expert" where applicable instead of specifying technical fields of expertise such as metallurgy or fracture mechanics. PHMSA believes these changes increase regulatory flexibility while maintaining pipeline safety.

In addition, as stated above, the spike test is being removed from the MAOP reconfirmation requirements. The spike test procedure in the new § 192.506 would be used whenever required by other requirements in part 192 to address crack remediation and the integrity threat of cracks and crack-like defects.

PHMSA disagrees with allowing pneumatic spike tests to 1.5 times MAOP based on safety concerns. Pneumatic pressure tests are allowed in § 192.503(c), with certain limitations, for new, relocated, or replaced pipe. For new, relocated, or replaced pipe, there is knowledge that the pipe is likely sound and is usually manufactured with recent mill pressure tests to confirm the pipe meets applicable standards. A spike test to perform an integrity assessment on *in-situ* pipe with known or suspected cracks or crack-like defects presents a much higher likelihood of the pipeline segment experiencing a leak or rupture during the test with resultant consequences, including the possibility of fire or explosion. PHMSA notes that conducting a pneumatic test using a compressible gas, such as air, nitrogen, or methane, would be a safety concern for the public and operating personnel. Gas that is highly compressed has stored energy that would be suddenly released should there be a flaw in the pipe. Liquids, such as water, do not have the stored energy release that a compressible gas has should the pipe have a flaw that either leaks or ruptures. Therefore, the safety risk of performing a hydrostatic pressure test (with water) is much lower due to the less-compressible nature of liquids. Compressed gas would be a fire or explosion hazard to the public. However, as specified in the proposed and final rules, operators that desire to use a pneumatic spike test may propose using such a test, with justification, by submitting a notification to PHMSA.

B. MAOP Reconfirmation - § 192.624

iv. – Fracture Mechanics

1. Summary of PHMSA's Proposal

In the proposal, PHMSA determined that fracture mechanics analysis is a key aspect of meeting the congressional mandate to consider safety testing methodologies for MAOP reconfirmation of equal or greater effectiveness as a pressure test, including other alternative methods such as ILI. Demonstrating that knowledge gained from an ILI assessment provides an equivalent level of safety as a pressure test is technically challenging. An ILI assessment might reveal the presence of crack flaws and crack-like defects and characterize them within the accuracy of tool performance capabilities, but determining whether those cracks would survive a pressure test to reconfirm MAOP requires very in-depth and highly technical analysis. Such an analysis not only requires an accurate characterization of cracks, it also requires accurate and known metallurgical properties of the pipe. To address these aspects, PHMSA proposed more detailed requirements in § 192.921 for evaluating defects discovered during ILI to account for tool accuracy and other factors to accurately characterize flaw dimensions and support accurate fracture mechanics analysis. In addition, the material properties verification and documentation requirements PHMSA proposed are critical to performing fracture mechanics analysis of ILI-discovered defects that would be accurate enough to establish MAOP in a way that is demonstrably equivalent in safety to a pressure test. In the MAOP reconfirmation provisions, PHMSA proposed new requirements for fracture mechanics analysis for failure stress and cracks, listing specific requirements, standards, and data operators must use when performing a fracture mechanics analysis.

2. Summary of Public Comment

Most industry stakeholders were opposed to the proposed fracture mechanics requirements. AGA, New Mexico Gas Co., and TPA suggested that fracture mechanics have a limited place in preventing pipeline failures or predicting them accurately and should not be a component of MAOP reconfirmation. AGA stated that the rule should not prescriptively require fracture mechanics calculations to be performed for a broad range of applications but should be narrowed to include only transmission pipelines operating at a hoop stress greater than 30 percent SMYS, given that pipelines that operate below 30 percent SMYS have a strong tendency to leak rather than rupture.

Commenters also stated that requiring fracture mechanics as any part of the MAOP reconfirmation process was overly burdensome and unclear. Specifically, API stated that some of the requirements listed under the MAOP reconfirmation requirements were overly conservative and burdensome for most situations where this technique would be used. For instance, a commenter noted that there is no non-destructive evaluation (NDE) methodology for obtaining Charpy V-notch toughness values. Therefore, PHMSA's requirement to obtain Charpy V-notch toughness values eliminates the availability of non-destructive testing. Further, a commenter noted that the proposed ECA analysis prescribed a body toughness of 5-ft.-lbs. and a seam toughness of 1-ft.-lbs., which are arbitrary and very conservative. Vintage pipelines will not have Charpy v-notch toughness data, and requiring an overly conservative assumption of toughness is not reasonable. Toughness can vary depending on the manufacturer, the manufacturing method, and the pipe vintage, and it should not be prescribed in the regulations. The commenter further noted that using the conservative defaults, especially the overly conservative defaults PHMSA proposed, may result in an unacceptably short remaining life of the pipeline.

Similarly, commenters recommended PHMSA allow alternative methods of assessing strength properties that provide a suitable lower bound to the actual strengths. Allowing alternative methods will provide flexibility to consider conservative, but realistic, estimates of material properties. Commenters also stated that SMEs in both metallurgy and fracture mechanics are not needed to validate non-destructive test (NDT) methods. Engineers with knowledge in test validation methods but not necessarily metallurgy and fracture mechanics are capable of validating NDT methods.

More broadly, Energy Transfer Partners suggested that the proposed language for fracture mechanics is misplaced in MAOP reconfirmation and should be moved to the proposed requirements for non-HCA assessments, or elsewhere, since this text more closely resembles an "assessment." Other commenters agreed with that concept, suggesting fracture mechanics is more appropriate under the IM measures for threat mitigation rather than for MAOP reconfirmation.

As previously discussed in this document, the GPAC recommended PHMSA move the fracture mechanics analysis requirements out of the ECA method of MAOP reconfirmation and into a new stand-alone section in the regulations, making it a process for performing fracture mechanics analysis whenever required or allowed by part 192. The committee therefore recommended that PHMSA delete any cross-references to the MAOP reconfirmation and the spike pressure test provisions. The GPAC also recommended that operators make and retain specific records to document fracture mechanics analyses performed.

Along with moving the fracture mechanics analysis requirements to a stand-alone section, the GPAC had several specific recommendations related to how the requirements would function. The GPAC recommended PHMSA remove ILI tool performance specifications and replace them with a requirement for operators to verify tool performance using unity plots or equivalent technologies, and also recommended revisions to the fracture mechanics requirements by striking the sensitivity analysis requirements and replacing them with a requirement for operators to account for model inaccuracies and tolerances.

As it pertains to the Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) used in fracture mechanics analysis, the GPAC recommended that operators could use a conservative Charpy V-notch toughness value based on the sampling requirements of the material properties verification provisions or use Charpy V-notch toughness values from similar-vintage pipe until the actual properties are obtained through the operator's opportunistic testing program. The GPAC recommended that PHMSA clarify that default Charpy V-notch toughness values of 13-ft.-lbs. for pipe body and 4-ft.-lbs. for pipe seam only apply to pipe with suspected low-toughness properties or unknown toughness properties. Further, if a pipeline segment has a history of leaks or failures due to cracks, the GPAC recommended PHMSA require the operator to work diligently to obtain any unknown toughness data. In the interim, operators of such pipeline segments must use Charpy V-notch toughness values of 5-ft.-lbs. for pipe body and 1-ft.-lbs. for pipe seam. The GPAC also recommended PHMSA include a 90-day notification procedure similar to the previously agreed-upon procedure if operators wanted to request the use of differing Charpy V-notch toughness values.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed fracture mechanics requirements. After considering these comments and as recommended by the GPAC, PHMSA is moving the fracture mechanics analysis requirements out of the ECA method of MAOP reconfirmation and into a new stand-alone § 192.712 in the regulations, making it a process by which operators must perform fracture mechanics analysis whenever required by part 192. This change was made to increase the readability of the regulations. As a part of making these provisions into a stand-alone section in the regulations, PHMSA is also deleting the references within § 192.712 to the MAOP reconfirmation and the spike pressure test provisions. PHMSA is adding a requirement for operators to make and retain specific records documenting any fracture mechanics analyses performed. PHMSA is also removing ILI tool performance specifications and sensitivity analysis requirements and replacing them with a requirement for operators to verify tool performance using unity plots or equivalent technologies and to account for model inaccuracies and tolerances. This change will increase regulatory flexibility while maintaining pipeline safety.

Regarding the default Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) used in fracture mechanics analysis when actual values are not known, industry and the GPAC had significant comments. PHMSA is aware of pipe manufactured per API Specification 5L in this decade (2010-2019) with Charpy V-notch toughness values for the weld seam as low as 1-ft. lbs. that has been used in gas transmission pipelines. Furthermore, API 5L does not contain required minimum Charpy V-notch toughness values for the weld seam.

A single default assumed toughness value might be inappropriate or overly conservative under some circumstances, or it might be a proper choice under other circumstances. To address this issue in this final rule, PHMSA is allowing the use of: (1) Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperatures) from the same vintage and the same steel pipe manufacturers with known properties; (2) a conservative Charpy V-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607; (3) maximum Charpy V-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects if the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects; (4) maximum Charpy V-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion if the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects; or (5) other appropriate Charpy V-notch toughness values that an operator demonstrates can provide conservative Charpy V-notch toughness values for the analysis of the crack-related conditions of the line pipe upon submittal of a notification to PHMSA. These modifications will provide flexibility to operators for considering conservative but realistic estimates of material properties.

PHMSA is also clarifying that operators do not need to use distinct metallurgy and fracture mechanics subject matter experts to review fracture mechanics analyses. In this final rule, PHMSA is replacing that requirement with a general requirement stating that fracture mechanics analyses must be reviewed and confirmed by a qualified subject matter expert. PHMSA expects a qualified subject matter expert to be an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. The operator must be able to document that the individual is appropriately knowledgeable and experienced in the subject being assessed.

B. MAOP Reconfirmation - § 192.624

v. - Legacy Construction Techniques / Legacy Pipe

1. Summary of PHMSA's Proposal

PHMSA proposed to add a definition to part 192 for "legacy construction techniques," which defined historical practices used to construct or repair transmission pipeline segments that are no longer recognized as acceptable. In addition, PHMSA proposed a definition for "legacy pipe" that is defined by the presence of specific legacy manufacturing, welding, and joining techniques.

2. Summary of Public Comment

AGA expressed significant concerns with the proposed definitions of legacy pipe and legacy construction techniques for the purposes of part 192, commenting that PHMSA should eliminate the use of the terms entirely or otherwise revise these definitions to exclude currently acceptable manufacturing and construction techniques. AGA stated if PHMSA were to codify the definitions of legacy pipe and legacy construction techniques, then PHMSA should limit its catch-all provisions within the language of the definitions to pipes with a longitudinal joint factor of less than 1.0. Doing so would ultimately include pipes with unknown joint factors, as § 192.113 requires a default longitudinal joint factor of 0.80 for any pipe with an unknown longitudinal joint factor. Similarly, AGL Resources, Alliant Energy, Atmos Energy, and TECO Peoples Gas supported AGA's suggested revisions to the definitions of legacy construction techniques and legacy pipe. API commented that PHMSA's proposed definition of legacy construction technique inappropriately includes the repair technique of puddle welds and recommended PHMSA clarify the definitions of wrought iron and pipe made from Bessemer steel. Dominion Transmission commented there may be instances where the longitudinal seam for modern day pipe is unknown, yet the pipe is not a high-risk seam type. They stated that such pipe does not present an integrity threat and should be excluded from the "legacy pipe" definition.

Gas Piping Technology Committee commented that the proposed definition of legacy construction techniques seems to contain some erroneous information. They asserted that the proposed definition went too far by implying that all the listed methods are no longer used to construct or repair pipelines, stating that while wrinkle bends may no longer be a common construction technique, they are still allowed under § 192.315 for steel pipe operating at a pressure producing a hoop stress of less than 30 percent of SMYS. Similarly, Oleksa and Associates commented that some operators are still installing Dresser couplings.

The Michigan Public Service Commission staff suggested that PHMSA add to the definition of "legacy construction techniques" a subsection that addresses other legacy construction techniques that are not in the current list and include within this subsection language referencing “all other” techniques. Northern Natural Gas proposed PHMSA eliminate the phrase “including any of the following techniques” from the definition of legacy construction techniques as it implies the list is not complete. They suggested that the definition of legacy pipe should differentiate between ductile and brittle pipe by toughness values in both the seam and the pipe body. Lastly, SoCalGas thought it would be more appropriate to reference these definitions under the IM regulations in subpart O instead of defining the terms in the context of the entire part.

These definitions were taken up by the GPAC in the context of the scope of MAOP reconfirmation, and they recommended in the meeting on March 26, 2018, that the definitions be withdrawn. Because the GPAC recommended to revise the scope of MAOP confirmation to not include pipelines with previous reportable incidents due to crack defects, these definitions would no longer be needed in the rule.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed definitions for “legacy pipe” and “legacy construction techniques.” After considering these comments and as recommended by the GPAC, PHMSA is withdrawing these definitions from the final rule. Because the revised scope of MAOP confirmation requirements, discussed in the previous sections, no longer includes pipelines with previous reportable incidents due to crack defects, these definitions are no longer necessary.

C. Seismicity and other Integrity Management Clarifications - § 192.917

1. Summary of PHMSA’s Proposal

Subpart O of 49 CFR part 192 prescribes requirements for managing pipeline integrity in HCAs. It requires operators of covered segments to identify potential threats to pipeline integrity and use that threat identification in their integrity programs. Included within this 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 particular threats such as third-party damage and manufacturing and construction defects.

Following the PG&E incident, the NTSB recommended that PG&E evaluate every aspect of its IM program, paying particular attention to the areas identified in the incident investigation, and implement a revised IM program. PHMSA held a workshop on July 21, 2011, to address perceived shortcomings in the implementation of IM risk assessment processes and the information and data analysis (including records) upon which such risk assessments are based. PHMSA also sought input from stakeholders on these issues in the ANPRM.

Section 29 of the 2011 Pipeline Safety Act requires that operators consider the seismicity of the geographic area in identifying and evaluating all potential threats to each pipeline segment, pursuant to 49 CFR part 192. Pipeline threat analysis is addressed as one program element in the IM regulations in subpart O. Addressing seismicity is already implicitly required by § 192.917 as part of addressing outside force threat through the incorporation by reference of ASME B31.8S. Based on the direction of the mandate, PHMSA proposed to explicitly require that operators analyze seismicity and related geotechnical hazards, such as geology and soil stability, as part of the threat identification IM program element and mitigate those threats of outside force damage. PHMSA determined this would clarify expectations for this requirement and explicitly implement section 29 of the 2011 Pipeline Safety Act.

PHMSA also proposed revisions to § 192.917(e) to clarify that certain pipe designs must be pressure tested to assume that seam flaws are stable and that failures or changes to operating pressures that could affect seam stability are evaluated using fracture mechanics analysis.

2. Summary of Public Comment

There was broad support for explicitly requiring the consideration of the seismicity of a geographic area when identifying and evaluating all potential threats to a pipeline segment, and several stakeholders suggested minor revisions to the proposal. California Public Utilities Commission (CPUC) supported the proposed provisions and recommended adding text that would require consideration of any significant localized threat that could affect the integrity of the pipeline. CPUC further commented that operating conditions on the pipeline must also be a factor when operators identify local threats.

Some commenters, including PG&E and NGA, requested further clarification regarding what would constitute a seismic event for the purposes of identifying threats under the IM program for compliance purposes. AGA requested clarification on the requirements regarding whether operators are expected to conduct a one-time investigation on the risk of seismicity and geology, or if there is an expectation of a periodic requirement for re-investigation.

Multiple commenters disagreed with the proposed requirement in § 192.917(e) for operators to perform annual cyclic fatigue analyses if an operator identifies cyclic fatigue as a threat. INGAA and National Fuel suggested that cyclic fatigue is an uncommon risk for natural gas pipelines and asserted that PHMSA did not provided significant technical justification for this analysis requirement. Some commenters suggested that the proposal to address cyclic fatigue and require pressure tests on seam threats is an overcompensation for the level of risk the threats present. Trade associations and pipeline industries proposed several alternative requirements for the conditions under which cyclic fatigue analyses should be required. API stated that they did not object to the measures listed, but the proposed provisions in § 192.935(b)(2) imply that an operator must take all the actions listed. API asserted that PHMSA should modify this proposed provision to state that operators must consider taking the actions listed but would not be specifically required to take all of them. Other commenters expressed concern that these proposed requirements conflict with the proposed requirements for pipeline segments needing to undertake MAOP reconfirmation because they experienced an incident due to manufacturing and construction (M&C) defects. Specifically, the requirements under § 192.917(e)(3) only allow operators to consider M&C defects stable if they have been subjected to a hydrostatic pressure test of 1.25 times MAOP, which would seemingly disallow or otherwise make fruitless the other methods of MAOP reconfirmation for these types of pipeline segments.

At the GPAC meeting on January 12, 2017, the GPAC recommended that no changes should be made to the proposed provisions on seismicity.

Regarding § 192.917(e)(2), which was discussed during the meeting on June 6-7, 2017, the GPAC noted that, under this provision, operators should be monitoring for condition changes that would cause the threat to potentially activate, and those condition changes should be what triggers a reassessment. The GPAC also noted problems with a suggested revision of performing a cyclic fatigue analysis within a 7-calendar-year period to match certain IM requirements because it would then impose a hard deadline on the continuous monitoring process and would prompt operators to act and again study cyclic fatigue even if the monitoring showed no evidence of cyclic fatigue being a threat. At the meeting, PHMSA suggested that operators could ensure the data involved in a cyclic fatigue analysis is periodically verified within a period not exceeding 7 years to align with IM requirements, but operators would only be required to perform a full evaluation if the data has changed. Following that discussion, the GPAC recommended revising the proposed requirements for cyclic fatigue at § 192.917 based on the discussion of GPAC members and considering PHMSA's proposed language that was presented at the meeting.

At the GPAC meeting on March 26-28, 2018, a public commenter suggested PHMSA remove the word "hydrostatic" from the requirements for considering M&C-related defects stable because any strength test that is approved in subpart J should qualify. Further, that public commenter suggested adding language where a pressure reduction or an ILI assessment with an ECA could be allowed for M&C defects as well. Another public commenter suggested removing references to cracks in these sections if PHMSA was intending to create a new section dedicated to addressing crack defects.

Ultimately, the GPAC recommended PHMSA revise the proposed requirements for M&C defects by deleting a cross-reference with the MAOP reconfirmation requirements, updating an applicability reference, and considering removing the term “hydrostatic” while allowing other authorized testing procedures. For the requirements related to electric resistance welded (ERW) pipe, the GPAC recommended PHMSA delete the phrase related to pipe body cracking and have those requirements be addressed in a new section within the IM regulations related to crack defects.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the consideration of seismicity and manufacturing- and construction-related defects under the IM regulations. After considering these comments as well as recommendations by the GPAC, PHMSA is revising § 192.917(e)(2) to require operators monitor operating pressure cycles and periodically determine if the cyclic fatigue analysis is valid at least once every 7 calendar years, not to exceed 90 months, as necessary. PHMSA is also deleting a reference to the MAOP reconfirmation requirements in § 192.624 and is referencing the new § 192.712 for fracture mechanics analysis. PHMSA believes these changes are consistent with current IM requirements and will increase regulatory flexibility while maintaining pipeline safety.

In § 192.917(e)(3), PHMSA deleted a cross-reference to the MAOP reconfirmation requirements in § 192.624 and replaced it with a requirement to prioritize the pipeline segment if it has experienced an in-service reportable incident since its most recent successful subpart J pressure test due to an original manufacturing-related defect; or a construction-, installation-, or fabrication-related defect. This clarifies that the IM requirement in § 192.917(e)(3) is not part of the MAOP reconfirmation standards. Although the GPAC asked PHMSA to consider removing the term "hydrostatic" and allow other testing procedures, PHMSA is retaining the term "hydrostatic" in § 192.917(e)(3), as the proposed revision, as written, addresses NTSB recommendation P-11-15. The NTSB specifically recommended that PHMSA amend part 192 so that manufacturing- and construction-related defects can only be considered stable following a postconstruction hydrostatic pressure test of at least 1.25 times the MAOP. Therefore, deleting the word "hydrostatic" would be contrary to the letter and intent of this NTSB recommendation.

For the requirements related to ERW pipe in § 192.917(e)(4), PHMSA has deleted the phrase related to pipe body cracking and deleted a cross-reference to the MAOP reconfirmation requirements in § 192.624, referencing the new § 192.712 for fracture mechanics analysis instead for cracking and crack-related issues. PHMSA made these changes to streamline the regulations and increase readability.

D. 6-month Grace Period for 7-calendar-year Reassessment Intervals - § 192.939

1. Summary of PHMSA's Proposal

Section 5 of the 2011 Pipeline Safety Act identifies a technical correction amending 49 U.S.C. 60109(c)(3)(B) to allow the Secretary of Transportation to extend the 7-calendar-year IM 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. The NPRM proposed to codify this technical correction as required by the statute.

2. Summary of Public Comment

PHMSA received a comment regarding the 6-month grace period for the 7-calendar-year reassessment interval from a trade organization expressing general support of the proposed provisions and requesting that PHMSA clarify that the 6-month extension begins after the close of the 7-calendar-year reassessment interval period, which would be consistent with the 2011 Pipeline Safety Act revision to the Federal Pipeline Safety Statutes.

At the GPAC meeting on January 12, 2017, the GPAC voted that the proposed changes on the 6-month grace period for the reassessment intervals are technically feasible, reasonable, cost-effective, and practicable, and did not recommend that PHMSA modify these proposed provisions.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the grace period for IM reassessment intervals. After considering the comment and as recommended by the GPAC, PHMSA is retaining the proposed revisions to § 192.939 in this final rule. The proposed rule clearly stated that the 6-month extension begins after the close of the 7-calendar-year reassessment interval period. This is mirrored in PHMSA's frequently asked questions (FAQ) for the IM program,[72]which clarifies that the maximum interval for reassessment may be set using the specified number of calendar years in accordance with the 2011 Pipeline Safety Act. The use of calendar years is specific to gas pipeline reassessment interval years under IM and does not alter the interval requirements that appear elsewhere in the code for various inspection and maintenance requirements.

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[72] FAQ-41 at https://primis.phmsa.dot.gov/gasimp/faqs.htm.

E. ILI Launcher and Receiver Safety - § 192.750

1. Summary of PHMSA's Proposal

PHMSA determined that more explicit safety requirements are needed when performing maintenance activities that use launchers and receivers for inserting and removing ILI maintenance tools and devices. The current regulations for hazardous liquid pipelines under part 195 have, since 1981, contained safety requirements for scraper and sphere facilities. However, the current regulations for natural gas transmission pipelines do not similarly require controls or instrumentation to protect against an inadvertent breach of system integrity due to the incorrect operation of launchers and receivers for ILI tools, or scraper and sphere facilities. As a result, PHMSA proposed to add a new section to the Federal Pipeline Safety Regulations to require ILI launchers and receivers include 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. While most launchers and receivers are already equipped with such devices, some older facilities may not be so equipped. Under the proposed provisions, operators would be required to have this safety equipment installed consistent with current industry practice.

2. Summary of Public Comment

Stakeholders, including TPA, provided input on PHMSA's changes to the requirements for safety when performing maintenance activities that utilize launchers and receivers for inserting and removing inspection and maintenance tools and devices. TPA supported the proposed safety additions to the regulations but stated that § 192.750 should be included within the regulations for pipeline components rather than the subpart for pipeline maintenance. In addition, TPA suggested PHMSA revise the language to allow 18 months after the effective date of the rule to comply with the provisions. This change would allow for more time to plan, budget, and complete the work safely. Another commenter recommended these provisions be effective prior to the next time an operator would use an applicable launcher or receiver. Public interest groups and others, such as PST and NAPSR, had broad support for the proposed provisions regarding ILI launcher and receiver safety.

At the GPAC meeting on January 12, 2017, a public commenter suggested clarification on PHMSA's use of the term "relief device" or "relief valve" within the proposed provisions. During discussion, the committee noted that there are requirements for "relief valves" elsewhere in the code, and calling a needed safety device for ILI launchers and receivers a "relief valve" would then make it subject to those additional requirements. Based on that discussion, the committee recommended that PHMSA modify the proposed rule to clarify that the rule does not require "relief valves" or use "relief valve" as an officially defined term within the provision, as those terms have distinct meanings within the broader context of the Federal Pipeline Safety Regulations.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding launcher and receiver safety. After considering these comments and the GPAC input, PHMSA is finalizing the provisions as they were proposed in the NPRM, with the exception of a compliance date 1 year after the effective date of the rule. This approach avoids disruption of work planned within a year of the effective date of the rule, and it allows operators that are not planning work until beyond the 1-year grace period to implement the upgrade before the next planned use. Therefore, special modification work would not be required before the launcher or receiver is needed. Operators would not be required to perform the upgrades until the launcher or receiver is to be used.

Consistent with the originally proposed language, this final rule does not use the term "relief valve" and instead uses the generic phrase "device capable of safely relieving pressure." The proposed rule effectively avoided any potential for confusion with respect to the defined term "relief valve" and the requirements associated with those components, therefore no change to this wording was necessary for this final rule.

PHMSA believes that this requirement is appropriately located in subpart M, "Maintenance," of part 192, and notes that the comparable requirement in part 195 for hazardous liquid pipelines is located in subpart F, "Operations and Maintenance."

F. MAOP Exceedance Reporting - §§ 191.23, 191.25

1. Summary of PHMSA's Proposal

Section 23 of the 2011 Pipeline Safety Act requires that operators report each exceedance of a pipeline's MAOP beyond the build-up allowed for the operation of pressure-limiting or control devices. On December 21, 2012 (77 FR 75699), PHMSA published Advisory Bulletin ADB-2012-11 to advise operators of their responsibility under section 23 of the 2011 Pipeline Safety Act to report such exceedances. The advisory bulletin further stated that the reporting requirement is applicable to all gas transmission pipeline facility owners and operators. PHMSA advised pipeline owners and operators to submit this information in the same manner as safety-related condition reports. The information pipeline owners and operators submit should comport with the information listed at § 191.25(b), and pipeline owners and operators submitting such information should use the reporting methods listed at § 191.25(a).

Although this provision of the 2011 Pipeline Safety Act is self-executing, PHMSA proposed to revise the safety-related condition reporting requirements under part 191 to codify this requirement and harmonize part 191 with the statutory requirement by eliminating the reporting exemption and to provide a consistent procedure, format, and structure for operators to submit such reports.

2. Summary of Public Comment

Trade associations, citizen groups, and pipeline industries generally supported PHMSA's codification of the statutory reporting requirements for MAOP exceedances for transmission lines.

API and GPA objected to MAOP exceedance reporting requirements for unregulated gathering pipelines. GPA stated that PHMSA did not sufficiently weigh the benefits of reporting MAOP exceedance against the hurdles to compliance for unregulated gathering pipelines. GPA also questioned whether PHMSA has the authority to require unregulated gathering pipelines report MAOP exceedance, since complying with this reporting requirement would necessitate that unregulated gathering pipelines establish MAOP, which they are currently not required to do. Citizen and other safety groups, including Earthworks, NAPSR, the Pipeline Safety Coalition, and PST, supported the inclusion of unregulated gathering pipelines in this section, stating that it would improve pipeline safety.

Several commenters suggested editorial revisions to streamline and improve these provisions. NGA expressed concern that the proposed provisions could apply to distribution systems and suggested that PHMSA clarify that reporting requirements for MAOP exceedance only apply to transmission pipelines. Additionally, Spectra Energy Partners requested that

PHMSA require reporting of MAOP exceedances only when the operator is unable to respond to MAOP exceedances within the timeframe required elsewhere in part 192.

One operator expressed concern that the proposed change would require operators to submit additional safety-related condition reports anytime the operator had to implement a pressure reduction upon discovering an immediate condition.

At the GPAC meeting on June 7, 2017, there was brief discussion on whether the 5-day reporting requirement was too prescriptive, but the committee agreed that PHMSA was properly implementing the statutory requirement as written and intended by Congress. Following that discussion, the committee recommended that PHMSA modify the proposed rule to clarify that the MAOP exceedance reporting provisions do not apply to gathering lines.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding MAOP exceedance reporting. The 2011 Pipeline Safety Act mandates that an operator report MAOP exceedances on gas transmission lines, regardless of whether the operator corrects the safety-related condition through repair or replacement. After considering the comments PHMSA received on the NPRM and as recommended by the GPAC, PHMSA is inserting the word “only” in the additional MAOP exceedance reporting provision in § 191.23(a)(10) to make it clearer that the amended requirement applies only to gas transmission lines and not to gathering or distribution lines. Conforming changes were made to § 191.23(a)(6). PHMSA notes that the prior safety-related condition reporting requirements and exceptions related to pressure exceedances for gathering and distribution lines have not been altered.

G. Strengthening Assessment Requirements - §§ 192.150, 192.493, 192.921, 192.937, Appendix F

i. Industry Standards for ILI – §§ 192.150, 192.493

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to revise § 192.150 to incorporate by reference a NACE Standard Practice, NACE SP0102-2010, "In-line Inspection of Pipelines," to promote a higher level of safety by establishing consistent standards for the design and construction of pipelines to accommodate ILI devices.

In § 192.493, PHMSA proposed requirements for operators to comply with the requirements and recommendations of API STD 1163, In-line Inspection Systems Qualification Standard; ANSI/ASNT ILI-PQ-2005, In-line Inspection Personnel Qualification and Certification; and NACE SP0102-2010, In-line Inspection of Pipelines. PHMSA also proposed to allow operators to conduct assessments using tethered or remotely controlled tools.

2. Summary of Public Comment

NAPSR supported the proposed provisions in § 192.493, commenting that the incorporation by reference of the three consensus standards provides enhanced guidance for the determination of adequate procedures and qualifications related to in-line inspections of transmission pipelines.

Some industry representatives commented that it is unnecessary to incorporate American Society for Nondestructive Testing (ASNT) ILI-PQ by reference since API 1163 requires that providers of ILI services ensure that their employees are qualified. Others commented that PHMSA should exclude requirements contained in section 11 of API 1163, which pertains to quality management systems. Lastly, industry representatives asserted that ILI vendors may not be able to meet the 90 percent tool tolerance specified in the referenced standards, and PHMSA should relocate these proposed requirements to a different subpart.

Several commenters noted that if PHMSA required compliance with "the requirements and recommendations of" the recommended practices and standards, it would create enforceable requirements out of actions that the standards themselves did not necessarily mandate.

During the GPAC meeting of March 2, 2018, the committee recommended PHMSA revise this provision by striking the phrase "the requirements and the recommendations of," so that recommendations within the incorporated standard would not be made mandatory requirements.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the incorporation by reference of industry standards for ILI. After considering these comments and as recommended by the GPAC, PHMSA is deleting the phrase "the requirements and the recommendations of" from §§ 192.150 and 192.493 so that the recommendations within the incorporated standard would not be made mandatory requirements.

PHMSA believes that the inclusion of the NACE standard at § 192.150 will help to address the NTSB recommendation P-15-20, which asked PHMSA to identify all operational complications that limit the use of ILI tools in piggable pipelines, develop methods to eliminate those complications, and require operators use such methods to increase the use of ILI tools. PHMSA also believes that more pipelines will become piggable in the future as the nation's pipeline infrastructure ages and is eventually replaced. A current provision in the regulations requires that all new and replaced pipeline be piggable, and as operators address higher-risk infrastructure through this rulemaking, there is a likelihood that some previously unpiggable pipe will be replaced.

PHMSA disagrees that ASNT ILI-PQ is unnecessary. The foreword of API 1163 states "*This standard serves as an umbrella document to be used with and complement companion standards. NACE SP0102, In-line Inspection of Pipelines and ASNT ILI-PQ, In-line Inspection Personnel Qualification and Certification.*" These three standards are complimentary and are intended to be used together. PHMSA also disagrees that quality requirements should be excluded from the rule. One of the fundamental objectives of this rule is to establish a minimum standard for quality in conducting ILI. Also, the consensus industry standard API 1163 only uses 90 percent tool tolerance as an example to illustrate key points but does not specify or establish a minimum standard tool tolerance of 90 percent.

G. Strengthening Assessment Requirements - §§ 192.150, 192.493, 192.921, 192.937, Appendix F

ii. Expand Assessment Methods Allowed for IM – §§ 192.921(a) and 192.937(c)

1. Summary of PHMSA's Proposal

In the current Federal Pipeline Safety Regulations, § 192.921 requires that operators with pipelines subject to the IM rules must perform integrity assessments. Currently, operators can assess their pipelines using ILI, pressure test, direct assessment, and other technology that the operator demonstrates provides an equivalent level of understanding of the condition of the pipeline.

In the NPRM, PHMSA proposed to require that direct assessment only be allowed when the pipeline cannot be assessed using ILI. As a practical matter, direct assessment is typically not chosen as the assessment method if the pipeline can be assessed using ILI. Further, PHMSA proposed to add three additional assessment methods to the regulations:

1. A spike hydrostatic pressure test, which is particularly well-suited to address stress corrosion cracking 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 crossings are difficult to assess; and
3. Excavation with direct *in situ* examination.

2. Summary of Public Comment

NAPSR expressed its support for the proposed provisions. Many comments expressed concerns with the proposed provisions for the assessment methods regarding uncertainties in reported results. Multiple commenters stated that operators should be able to run the appropriate assessment or ILI tools for the threats that are known or likely to exist on the pipeline based on its condition. Atmos Energy commented that ASME/ANSI B318.S requirements should be the standard to which operators are required to follow. Enable Midstream Partners proposed that PHMSA add "significant" to make a distinction between significant and insignificant threats and offered specific language to address its concerns. PG&E commented on the proposed provisions for ILI assessments, requesting that PHMSA provide guidance as to how to explicitly consider the numerous uncertainties associated with ILI regarding anomaly location accuracy, detection thresholds, and sizing accuracy, and suggested that PHMSA allow industry guidance and best practices to be used where practical. Some commenters expressed concern that PHMSA proposed to add requirements surrounding the detection of anomalies that many ILI tools could not meet. These commenters stated that there are no tools designed to find girth weld cracks and that most incidents caused by girth weld cracks have third-party excavation damage as a contributing factor. Commenters further stated that this is a threat that is best handled by procedures that require caution around girth welds during excavation and backfilling procedures.

Several entities commented on the proposed qualification requirements under the ILI assessment method provisions, expressing concern that they are redundant with existing operator qualification regulations under the IM regulations at § 192.915 and the proposed revisions to § 192.493 incorporating the industry ANSI standard on ILI personnel qualification. Multiple entities proposed changes to remove such redundancies and improve clarity.

Commenters requested clarification that the proposed text in the IM assessment provisions "apply one or more of the following methods for each threat to which the covered segment is susceptible" does not mean that at least one assessment is required for each threat. Additionally, commenters disagreed with adding an explicit requirement for a "no objection" letter as notification of using "other technology" and suggested that if this notification is required, operators should be allowed to proceed with the technology if they do not receive a "no objection" letter from PHMSA within a certain period.

The NTSB commented that PHMSA's proposal to revise the pipeline inspection requirements to allow the direct assessment method to be used only if a line is not capable of inspection by internal inspection tools directly conflicts with the recommendations of their pipeline safety study, *Integrity Management of Gas Transmission Lines in High Consequence Areas*, which recommended that PHMSA develop and implement a plan for eliminating the use of direct assessment as the sole integrity assessment method for gas transmission pipelines. The

CPUC asserted that direct assessment must always be supplemented with other methods, such as ILI or a pressure test.

Many industry entities argued that PHMSA's proposed changes to the IM assessment provisions limiting direct assessment to unpiggable lines are not technically justified. Several entities, including AGA and API, believed it was unreasonable to limit operators' ability to use direct assessment for pipeline assessments unless all other assessment methods have been determined unfeasible or impractical. PG&E requested that PHMSA recognize that although a pipeline may be considered piggable, it does not mean that ILI technology is available, and they provided specific suggestions for revision. Similarly, AGA stated that free-swimming flow-driven ILI tools are often not compatible with intrastate transmission lines for several reasons, stating that certain conditions must exist to assess a pipeline by ILI and obtain valid data, including adequate flow rate, lack of bends or valves that would impede diameter, and ability to insert and remove the tool from the system. Therefore, AGA provided a suggested definition for "able to accommodate inspection by means of an instrumented in-line inspection tool."

Trade associations asserted that direct assessment is a proven assessment technique that works in addressing the threat of corrosion. INGAA stated that the criteria for when direct assessment can be used should depend on whether direct assessment can provide the necessary information about the pipe condition rather than whether other assessment methods can be used. AGA commented that it is not aware of any industry study that would suggest that direct assessment does not work effectively to identify corrosion defects in certain circumstances, which it describes in its comments. In addition, AGA stated that direct assessment is a predictive tool that identifies areas where corrosion could occur, including time-dependent threats, while other methods can only detect where corrosion has resulted in a measurable metal loss. Atmos

Energy commented that limiting the use of direct assessment only to those pipeline segments that are not capable of inspection by internal inspection tools is not consistent with other requirements of subpart O.

At the GPAC meeting on December 15, 2017, the committee voted to revise the "no objection" process to incorporate language stating that, if an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA of an alternative sampling approach, the operator can proceed with their method. Additionally, the GPAC, during the meeting on March 2, 2018, recommended that PHMSA change these provisions to clarify that operators should select the appropriate assessment based on the threats to which the pipeline is susceptible and remove certain language that is duplicative to another existing section of the regulations. The GPAC also recommended that PHMSA clarify that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable. Further, the GPAC wanted PHMSA to incorporate the notification and objection procedure and 90-day timeframe that the GPAC approved under the material properties verification requirements.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the inclusion of additional assessment methods for integrity assessments. After considering these comments and as recommended by the GPAC, PHMSA is clarifying in this final rule that operators should select the appropriate assessment method based on the threats to which the pipeline is susceptible and is removing language regarding the qualification of persons reviewing ILI results that is duplicative with existing § 192.915. PHMSA is also clarifying in § 192.921 that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable, such as assessing pipe seam threats. In addition, PHMSA incorporated the notification procedure under § 192.18 with the 90-day timeframe and objection process.

PHMSA notes that other comments regarding the determination of suitable assessment methods for applicable threats and ILI tool capabilities relate to long-standing IM regulations that were not proposed for revision. PHMSA did provide substantial additional guidance and standards for implementing the integrity assessment requirements for ILI by incorporating the industry standards in § 192.493, as discussed in the previous sections.

G. Strengthening Assessment Requirements - §§ 192.150, 192.493, 192.921, 192.937, Appendix F

iii. Guided Wave Ultrasonic Testing – Appendix F

1. Summary of PHMSA's Proposal

When expanding assessment methods for both HCA and non-HCA areas, PHMSA proposed to add three additional assessment methods, one being GWUT. Under the existing regulations, GWUT is considered "other technology," and operators must notify PHMSA prior to its use. PHMSA developed guidelines for the use of GWUT, which have proven successful, and proposed to add them under a new Appendix F to part 192 - Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing. As such, future notifications to PHMSA would not be required, representing a cost savings for operators.

2. Summary of Public Comment

Multiple entities commented in support of using GWUT and the inclusion of proposed Appendix F. NAPSR expressed its agreement with and support for the proposed Appendix. American Public Gas Association (APGA) applauded PHMSA for including guidelines for GWUT; however, it cautioned that the guidance only specifies Guided Ultrasonics LTD (GUL) Wavemaker G3 and G4, which use piezoelectric transducer technology, as acceptable technology. APGA recommended that Magnetostrictive Sensor technology also be included as an acceptable guided wave technology, stating that at least one of its members reported good results using this technology for guided wave assessment of an unpiggable segment of a transmission pipeline.

A commenter noted that the requirement of both torsional and longitudinal wave modes in all situations introduces unnecessary complexity into the GWUT data interpretation process. The commenter further noted that PHMSA should specify that torsional wave mode is the primary wave mode when utilizing GWUT, and that longitudinal wave mode may be used as an optional, secondary mode. Other commenters recommended additional changes to Appendix F, such as stating that qualified GWUT equipment operators are trained to understand the strengths, weaknesses, and proper applications of each wave mode and should have the freedom to select the appropriate and most effective wave mode(s) for the given situation. PG&E requested that PHMSA recognize that this technology is used at locations other than casings as implied in the introductory paragraph and commented that double-ended inspections are not always required to meet the specification.

During the GPAC meeting on December 15, 2017, the GPAC agreed with the provisions related to Appendix F and GWUT but recommended PHMSA revise the “no objection” letter process.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding GWUT. After considering these comments and as recommended by the GPAC, PHMSA is removing the reference to GUL equipment for clarity. PHMSA is modifying the notification process to allow operators to proceed with an alternative process for using GWUT if the operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA in accordance with § 192.18. PHMSA believes this change increases regulatory flexibility while maintaining pipeline safety.

In this final rule, PHMSA is retaining the requirement to use both torsional and longitudinal wave modes since that is a long-standing requirement in PHMSA’s guidance for accepting GWUT as an allowed technology under an “other technology” notification. Also, PHMSA recognizes that GWUT is used at locations other than casings, although it is most often deployed for the integrity assessment of cased crossings. However, double-ended inspections would not always be required to meet Appendix F, and Appendix F does not require double-ended inspections. Double-ended inspections are not necessary as long as the guided wave ultrasonic test covers the entire length of the assessment as well as the “dead zone” where the equipment is set up.

The proposed rule already addresses validation of operator training, but in this final rule, PHMSA is deleting the sentence "[t]here is no industry standard for qualifying GWUT service providers" to provide clarity.

H. Assessing Areas Outside of HCAs - §§ 192.3, 192.710

i. MCA Definition - § 192.3

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA introduced a new definition for a Moderate Consequence Area (MCA). The proposed rule defined an MCA as an onshore area, not meeting the definition of an HCA, that is within a potential impact circle, as defined in § 192.903, containing 5 or more buildings intended for human occupancy; an occupied site; or a right-of-way for a designated interstate, freeway, expressway, or other principal four-lane arterial roadway as defined in the Federal Highway Administration's "Highway Functional Classification Concepts, Criteria and Procedures." PHMSA proposed that requirements for data analysis, assessment methods, and immediate repair conditions within these MCAs would be similar to requirements for HCA pipeline segments but with longer timeframes so that operators could properly allocate resources to higher-consequence areas. PHMSA proposed that the 1-year repair conditions that currently exist for HCA pipeline segments would be 2-year repair conditions when found on MCA pipeline segments. These changes would ensure the prompt remediation of anomalous conditions that could potentially affect people, property, or the environment, commensurate with the severity of the defects, while still allowing operators to allocate their resources to HCAs on a higher-priority basis.

2. Summary of Public Comment

The NTSB stated that the proposed provisions to create an MCA category and include a highway size threshold in the definition of an MCA accomplishes part of what the NTSB intended in Safety Recommendation P-14-1. However, the NTSB objected to the proposed highway coverage as being limited to four lanes and stated its support of expanding the highway size threshold as they had specifically recommended in P-14-1. The NTSB asserted that the proposed language would exclude the category of other principal arterial roadways wider than four lanes when, in fact, the wider roadways should be included.

INGAA supported the addition of an MCA category to the Federal Pipeline Safety Regulations but recommended several modifications to the proposed definition. INGAA suggested PHMSA should limit the definition of an MCA to only those pipeline segments that could be assessed through an ILI inspection, amend the MCA definition to avoid ambiguity regarding residential structures, remove "outside areas and open structures" from the portion of the definition of MCA related to "identified sites," include timeframes for incorporating changes to existing MCAs, and permit operators to use the edge of the pavement rather than the highway right-of-way to determine if a roadway intersects with a Potential Impact Circle.

AGA, API, APGA, and several pipeline entities agreed with INGAA's comments on the modification to PHMSA's proposed MCA definition. Additionally, AGA, API, and APGA emphasized PHMSA should remove the reference to "a right-of-way" for the designated roadways, commenting that the MCA definition could be interpreted so that if a Potential Impact Circle touches any portion of the roadway right-of-way, the pipeline segment is an MCA. That interpretation would put undue burden on operators in areas where its pipelines lay at or near the edge of the public right-of-way that would not normally contain “persons or property” that would sustain damage or loss in the event of a pipeline failure. Further, API added that the reference to “a right-of-way” is problematic because roadway right-of-ways are variable, cannot be seen with the naked eye, and are often not included in publicly available data sources.

Commenters also disagreed with the definition of “occupied site” within the MCA definition. GPA asserted that the criterion used in the MCA definition should be limited to interstate highways, and the definition of “occupied site” should be eliminated to more clearly distinguish between MCAs and HCAs and to provide greater clarity in identifying and managing MCAs. Similarly, Enlink Midstream commented that PHMSA should eliminate the definition of occupied site and remove this criterion from the proposed definition of MCA. Doing so would permit the continued focus on HCAs that the IM process was intended to accomplish. AGL Resources also expressed concern with the proposed definition of occupied site, commenting that this definition could require operators to effectively perform a census-like identification of structures to verify the count of persons within that structure.

There were conflicting viewpoints on where the definition of MCA should be placed in the regulations. API and other commenters stated that they preferred a new category and a distinct definition for MCA as opposed to expanding the definition of HCA or making a subcategory in the HCA definition for MCAs, whereas SoCalGas encouraged expanding the scope of HCAs rather than creating a new category.

Enterprise Products commented PHMSA should move the MCA definition to subpart O and remove the "occupied site" criteria from the proposed definition of MCA, which would provide more distinction between MCAs and HCAs in the regulations and would also more appropriately place them under the IM regulations.

AGA and several other organizations expressed concern over the resource-intensive administrative task of identifying MCAs, especially pertaining to recordkeeping requirements. API asserted that the proposed provisions would limit operators' ability to prioritize resources for pipelines that pose the highest risk. They further stated that while they agree with the inclusion of all Class 3 and Class 4 locations, occupied sites, and major roadways in the definition of MCA, they disagree with the proposed threshold of five buildings intended for human occupancy within the potential impact radius. They suggested that a more appropriate threshold would be more than 10 buildings intended for human occupancy, as that number is consistent with longstanding part 192 class location designations.

Multiple groups, such as AGI, INGAA, and Cheniere Energy, also stated objections over various aspects of defining and identifying MCAs and provided suggestions for revised language, including several broad clarifications or deletions to the definition. In addition to requesting modifications to the definition of MCA, INGAA objected to the provided geographic information system (GIS) layer for right-of-way determination, and suggested that PHMSA provide one database for roadway classification. Numerous trade associations and pipeline companies asked PHMSA to consider a qualifier that the definition of MCA only applies to pipelines operating at greater than 30 percent SMYS. EnLink Midstream suggested using a threshold level of 16-inch pipe diameter to identify pipelines that pose a greater risk.

The GPAC had a comprehensive discussion on the MCA definition during the meeting on March 2, 2018, and approved of the definition with some changes. First, the GPAC recommended changing the highway description within the definition to remove reference to the roadway "rights-of-way" and to add language so that the highway consists of "any portion of the paved surface, including shoulders." Secondly, the GPAC recommended clarifying that highways with 4 or more lanes are included, and they also wanted PHMSA to work together with the Federal Highway Administration to provide operators with clear information relative to this aspect of the rulemaking and discuss it in the preamble. The GPAC also recommended that PHMSA discuss in the preamble what they expect the definition of "piggable" to be, as it is critical for aspects of the MCA definition as it relates to MAOP confirmation. Finally, the GPAC recommended PHMSA modify the term "occupied sites" in the MCA definition and in the definitions section of part 192 by removing the language referring to "5 or more persons" and the timeframe of 50 days and tying the requirement into the HCA survey for "identified sites" as discussed by GPAC members and PHMSA at the meeting. The committee noted that such site identification could be made through publicly available databases and class location surveys. The committee suggested PHMSA consider the necessary sites and enforceability of the definition per direction by the committee members.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the definition of moderate consequence area. After considering these comments and the GPAC input, PHMSA is modifying the highway description within the definition to remove reference to the roadway "rights-of-way" and to add language so that the highway consists of "any portion of the paved surface, including shoulders." Also, PHMSA is specifying that highways with 4 or more lanes are included. PHMSA believes these changes provide additional clarity.

Per the GPAC's request that PHMSA provide additional guidance on what roadways are included in the MCA definition as it pertains to "other principal roadways with 4 or more lanes," PHMSA notes that the Federal Highway Administration defines *Other Principal Arterial* roadways[73] as those roadways that serve major centers of metropolitan areas, provide a high degree of mobility, and can also provide mobility through rural areas. Unlike their access-controlled counterparts (interstates, freeways, and expressways), abutting land uses can be served directly. Forms of access for *Other Principal Arterial* roadways include driveways to specific parcels and at-grade intersections with other roadways. For the most part, roadways that fall into the top three functional classification categories (Interstate, Other Freeways & Expressways, and Other Principal Arterials) provide similar service in both urban and rural areas. The primary difference is that there are usually multiple arterial routes serving a particular urban area, radiating out from the urban center to serve the surrounding region. In contrast, an expanse of a rural area of equal size would be served by a single arterial. The MCA definition does not include all roadways that meet this definition but instead is limited to those roadways meeting this definition that have four or more lanes.

With respect to "occupied sites," PHMSA evaluated the comments and the GPAC discussion and concluded that including occupied sites within the MCA definition was not necessary. Industry representatives on the GPAC asserted that most locations meeting the definition of occupied site are, as a practical matter, already included as an identified site and designated as an HCA. Commenters suggested most operators find it expedient to declare sites similar to occupied areas as HCAs instead of counting the specific occupancy of such locations to see if they meet the occupancy standard over the course of a year. Operators then monitor occupancy in subsequent years for changes that might change the site's status as an occupied site. Such an approach would require fewer resources and be more conservative from a public

[73] Federal Highway Administration, Office of Planning, Environment, & Realty (HEP), *Highway Functional Classification Concepts, Criteria and Procedures (2013)* https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/section03.cfm#Toc336872980

safety standpoint. Based on these comments, PHMSA is persuaded that including another category of locations, similar to identified sites in HCAs but with a lower occupancy standard of 5 persons, is unnecessarily burdensome without a comparable decrease in risk.

PHMSA disagrees that the MCA definition should be moved to subpart O. The term is used in sections outside of subpart O. Including the MCA definition in § 192.3 is necessary for it to apply to the sections in which it is used throughout part 192.

H. Assessing Areas Outside of HCAs - §§ 192.3, 192.710

ii. Non-HCA Assessments – § 192.710

1. Summary of PHMSA's Proposal

PHMSA proposed to add a new § 192.710 to require that pipeline segments in Class 3 or Class 4 locations, and piggable segments in MCAs, be initially assessed within 15 years and no later than every 20 years thereafter on a recurring basis. PHMSA also proposed to require assessments in these areas be conducted using the same methods that are currently allowed for HCAs. PHMSA has found that operators have assessed significant non-HCA pipeline mileage in conjunction with performing HCA integrity assessments in the same pipeline. Therefore, PHMSA proposed to allow the use of those prior assessments of non-HCA pipeline segments to comply with the new § 192.710.

In effect, to this limited population of pipeline segments outside of HCAs, PHMSA proposed to expand the applicability of IM program elements related to baseline integrity assessments, remediating conditions found during integrity assessments, and periodic reassessments. In addition, under the proposed provisions, MCAs would be subject to other requirements related to the congressional mandates, including material properties verification and MAOP reconfirmation. Any assessments an operator would conduct to reconfirm MAOP under proposed § 192.624 would count as an initial assessment or re-assessment, as applicable, under the proposed requirements for non-HCA assessments.

2. Summary of Public Comment

The NTSB and multiple citizen groups supported the expansion of IM elements to gas transmission pipelines in areas outside those currently defined as HCAs. However, several entities, including PST, stated that applying a limited suite of IM tools to these areas was insufficient and requested that the full suite of IM elements be applied to the additional pipeline segments. Some citizen groups expressed concern that the 15-year implementation period and 20-year re-inspection period was too long.

While pipeline companies and trade associations generally supported PHMSA's efforts to expand IM elements beyond HCAs, many of them stated concerns over the time and cost required to identify MCAs, the efficacy of the changes, and the language and requirements regarding both the limitation of assessments to pipeline segments accommodating inline inspection tools and (re)assessment periods. Many groups requested a clear, concise set of codified requirements for IM outside of HCAs to simplify identification, recordkeeping, and repairs.

Several commenters provided input on the allowable assessment methods for non-HCAs. AGA suggested that PHMSA create a new subpart consisting of a clear and concise set of codified requirements for the non-HCA assessments, including new definitions regarding the limitation of assessments to pipeline segments accommodating instrumented inline inspection tools. Many trade associations and pipeline companies stated that they thought the direct assessment method could achieve a satisfactory level of inspection in place of costlier in-line inspection, especially given the additional detail added to the in-line inspection assessment method in the proposal. API requested that PHMSA allow operators to rely on any prior assessments performed under subpart O requirements of part 192 in effect at the time of the assessment rather than limit the allowance to ILI. Furthermore, other organizations supported AGA's proposal that mirrors and extends to MCAs the two-methodology approach used to determine HCAs in the existing § 192.903, which allows for identification based on class location or by the pipeline's potential impact radius.

Entities, including API and Atmos Energy, requested clarification regarding assessment periods and reassessment intervals due to the language regarding shorter reassessment intervals "based on the type [of] anomaly, operational, material and environmental conditions […], or as otherwise necessary." Those commenters said that language was vague and subject to varying interpretations, so they suggested revisions to the language for the reassessment intervals. Lastly, AGA suggested that PHMSA define the term "pipelines that can accommodate inspection by means of an instrumented in-line inspection tool" used in proposed §§ 192.710 and 192.624, stating that providing the criteria that a pipeline must meet to be able to accommodate an in-line inspection tool would remove uncertainty and inconsistency in determining which pipelines meet PHMSA's proposed qualifier.

The GPAC discussed the provisions related to assessments outside of HCAs during the meeting on March 2, 2018. The GPAC found the provisions to be technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that direct assessment could be used only if appropriate for the threat being assessed and could not be used to assess threats for which direct assessment is not suitable, and removed the provisions related to low-stress assessments. The GPAC also recommended revising the initial assessment and reassessment intervals for applicable pipeline segments from an initial assessment within 15 years of the effective date of the rule and periodic assessments every 20 years thereafter to an initial assessment within 14 years of the effective date of the rule and periodic assessments every 10 years thereafter. The GPAC stated that the prioritization of initial assessments and reassessments should be based on the risk profiles of the pipelines. The GPAC also wanted PHMSA to apply the assessment and reassessment requirements only to pipelines with MAOPs greater than or equal to 30 percent SMYS.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding integrity assessments outside HCAs. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to specify that direct assessment may be used only if appropriate for the threat being assessed and cannot be used to assess threats for which direct assessment is not suitable, such as assessing pipe seam threats. PHMSA made these changes to provide clarity regarding the proper use of direct assessments.

In addition, PHMSA is revising the applicability of § 192.710 to apply only to pipelines with an MAOP of greater than or equal to 30 percent of SMYS. PHMSA made this change because the GPAC recommended it was cost-effective for the provision to only apply to pipe operating above 30% SMYS in Class 3 and 4 locations and because those pipelines present the greatest risk to safety. Because of this modification, PHMSA is withdrawing provisions related to low-stress assessments since they will no longer be applicable.

Based on the comments and recommendations from the GPAC, PHMSA is also modifying the initial assessment deadline and reassessment intervals for applicable pipeline segments to 14 years after the publication date of the rule and every 10 years thereafter, which was reduced from 15 years and 20 years, respectively. PHMSA believes this change increases regulatory flexibility while maintaining pipeline safety. PHMSA is also adding a requirement that the initial assessments must be scheduled using a risk-based prioritization.

PHMSA disagrees with the need to implement a dual approach to MCA identification that would be similar to the ways that HCAs are identified. Subpart O and the IM regulations were first promulgated before pipeline operators had experience with potential impact radius (PIR) techniques, and incorporating an alternative HCA identification method into the original IM regulations using conventional class locations was convenient and appropriate. Pipeline operators now have over 15 years of experience working with the PIR concept; therefore, PHMSA determined using the PIR method for determining MCAs in the definition of MCAs is appropriate. PHMSA also disagrees that a separate subpart would be preferable and is retaining the requirements for MCA assessments in a new § 192.710.

PHMSA believes the requirement to have a shorter reassessment interval is clear and is not modifying that aspect of the rule. PHMSA included a requirement for operators to not automatically default to the maximum reassessment interval but to establish shorter reassessment intervals "based upon the type anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety" when appropriate. Operators have been required to perform similar analyses and adjustment of reassessment intervals for HCAs since the inception of the IM regulations in 2003 and should be familiar with this process over 15 years later. PHMSA believes that stating the overarching goal of assuring public safety by evaluating each pipeline and its circumstances and establishing appropriate assessment intervals based on those circumstances provides clear intent and is an appropriate approach.

PHMSA believes that the term “piggable segment” is very widely understood in the industry and is not including additional definitions or regulatory language to expand upon this term. PHMSA understands that a pipeline segment might be incapable of accommodating an in-line inspection tool for a number of reasons, including but not limited to short radius pipe bends or fittings, valves (reduced port) that would not allow a tool to pass, telescoping line diameters, and a lack of isolation valves for launchers and receivers. Some unpiggable pipelines can be made piggable with modest modifications, but others cannot be made piggable short of pipe replacement.

PHMSA understands that a pipeline segment is piggable if it can accommodate an instrumented ILI tool without the need for major physical or operational modification, other than the normal operational work required by the process of performing the inline inspection. This normal operational work includes segment pigging for internal cleaning, operational pressure and flow adjustments to achieve proper tool velocity, system setup such as valve positioning, installation of temporary launchers and receivers, and usage of proper launcher and receiver length and setup for ILI tools. In addition, a pipeline segment that is not piggable for a particular threat because of limitations in technology such that an ILI tool is not commercially available, might be piggable for other threats. For example, a pipeline that is unable to accommodate a crack tool might be able to accommodate a conventional MFL or deformation tool, and thus be piggable for those threats. Launcher and receiver lengths are not a reason for a pipeline to be considered unpiggable, since through a minor modification they can be modified to be piggable, and the removal of launchers or receivers from the pipeline segment does not make a pipeline unpiggable either.

I. Miscellaneous Issues

i. Legal Comments

The following section discusses industry comments related to legal and administrative procedure issues with the proposed rule.

Summary of Public Comment

Several commenters asserted that the proposed provisions go beyond PHMSA's statutory authority provided by the 2011 Pipeline Safety Act. Many trade associations and pipeline industry entities stated that PHMSA exceeded the congressional mandates in the proposed provisions by imposing retroactive recordkeeping requirements and retroactive material properties verification requirements. These comments are discussed in more detail in their respective sections above.

Commenters asserted that, in the 2011 Pipeline Safety Act, Congress identified specific factors that PHMSA is required to consider when proposing regulations per the statutory mandates, including whether certain proposed provisions would be economically, technically, and operationally feasible, and that the proposed rule did not adequately address these factors. For example, AGA expressed concerns that PHMSA proposed to adopt NTSB recommendations without independently justifying those provisions based on the specific factors required by Congress or providing the reasoning behind adopting said recommendations.

AGA and INGAA also stated that PHMSA did not adequately consider the impact that the Natural Gas Act of 1968 would have on implementation of the proposed rule. Noting that operators are required to obtain permission from FERC before removing pipelines from service or replacing pipelines, these commenters stated that obtaining permissions could hinder operators from quickly performing required tests and repairs. INGAA and AGA also stated that PHMSA did not consult with FERC and State regulators about implementation timelines for certain provisions, which PHMSA is required to do in accordance with 49 U.S.C. § 60139(d)(3) because gas service would be affected by the proposed rule.

PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the statutory authority for the proposed rule. With regard to the comments about imposing retroactive recordkeeping requirements and retroactive material properties verification requirements, PHMSA explained in this document that the final provisions of this rule are prospective and do not create retroactive requirements. This topic is discussed in more detail in the respective sections about recordkeeping and material properties verification.

Pertaining to PHMSA's broader authority, Congress has authorized the Federal regulation of the transportation of gas by pipeline in the Pipeline Safety Laws (49 U.S.C. §§ 60101 et seq.) and established the current framework for regulating pipelines transporting gas in the Natural Gas Pipeline Safety Act of 1968, Pub. L. No. 90-481. Through these laws, Congress has delegated the 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. As required by law, PHMSA has considered whether the provisions of this rule are economically, technically, and operationally feasible and has provided relevant analysis in the Regulatory Impact Analysis and preamble of this rule.

In accordance with section 23 of the 2011 Pipeline Safety Act, PHMSA consulted with the Federal Energy Regulatory Commission and State regulators as appropriate to establish the timeframes for completing MAOP reconfirmation. As a part of this consultation, PHMSA accounted for potential consequences to public safety and the environment while also accounting for minimal costs and service disruptions. Furthermore, PHMSA will note that both a FERC member and a NAPSR member are on the GPAC, providing both input and positive votes that the provisions were technically feasible, reasonable, cost-effective, and practicable if certain changes were made. As previously discussed, PHMSA has taken the GPAC's input into consideration when drafting this final rule and made the according changes to the provisions.

I. Miscellaneous Issues

ii. - Records

1. Summary of PHMSA's Proposal

Many pipeline 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 data is obtained through testing and inspection under the existing IM requirements. Section 192.917(b) requires operators to gather pipeline attribute data as listed in ASME/ANSI B31.8S – 2004 Edition, section 4, table 1. ASME/ANSI B31.8S – 2004 Edition, section 4.1 states:

> "*Pipeline operator procedures, operation and maintenance plans, incident information, and other pipeline operator documents specify and require collection of data that are*

suitable for integrity/risk assessment. Integration of the data elements is essential in order to obtain complete and accurate information needed for an integrity management program. Implementation of the integrity management program will drive the collection and prioritization of additional data elements required to more fully understand and prevent/mitigate pipeline threats."

However, despite this requirement, 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. Therefore, PHMSA proposed amendments to the records requirements for part 192, specifically under the general recordkeeping requirements, class location determination records, material mechanical property records, pipe design records, pipeline component records, welder qualification records, and the MAOP reconfirmation provisions.

2. Summary of Public Comment

Several commenters provided input on the proposed amendments to the records requirements for part 192. Several public interest groups, including Pipeline Safety Coalition and PST, supported the increased emphasis on recordkeeping requirements, stating that the requirements are a proactive response to NTSB recommendations and are common-sense business best practices.

Several commenters opposed the proposed provisions providing general recordkeeping requirements for part 192. Commenters asserted that these proposed provisions apply significant new recordkeeping requirements on operators by requiring that operators document every aspect of part 192 to a higher and impractical standard than before. Commenters also stated that the proposed recordkeeping requirements appear to be retroactive and stated that it would be inappropriate to require operators to document compliance in cases where there have not been requirements to document or retain records in the past. Commenters also asserted that the Pipeline Safety Laws at 49 U.S.C. § 60104(b) prohibits PHMSA from applying new safety standards pertaining to design, installation, construction, initial inspection, and initial testing to pipeline facilities already existing when the standard is adopted, and that PHMSA does not have the authority to apply these requirements retroactively. These commenters suggested that even the recordkeeping requirements in these non-retroactive subparts could not be changed under PHMSA's current authority. Subsequently, commenters requested that PHMSA confirm that the proposed general, material, pipe design, and pipeline component recordkeeping requirements would not apply to existing pipelines and that recordkeeping requirements for the qualification of welders and qualifying plastic pipe joint-makers would not apply to completed pipeline projects.

Additionally, several commenters also requested that PHMSA clarify that many of the proposed recordkeeping requirements apply only to gas transmission lines. AGA also expressed concern regarding the proposed reference to material properties verification requirements in the proposed general recordkeeping requirements, which, as written, would also require distribution pipelines without documentation to comply with the proposed material properties verification requirements.

Many commenters opposed the proposed application of the term "reliable, traceable, verifiable, and complete" in part 192 beyond the requirements for MAOP records, and AGA recommended the deletion of "reliable, traceable, verifiable and complete" from proposed provisions under MAOP reconfirmation. Similarly, other commenters, including INGAA, recommended omitting "reliable" from the phrase and provided a suggested definition for "traceable, verifiable, and complete" records. Additionally, commenters opposed the use of this term in the general recordkeeping requirements at § 192.13, stating that it would apply a new standard of documentation to part 192. Citing a 2012 PHMSA Advisory Bulletin in which PHMSA stated that verifiable records are those "in which information is confirmed by other complementary, but separate, documentation," INGAA requested that PHMSA acknowledge that a stand-alone record will suffice and a complementary record is only necessary for cases in which the operator is missing an element of a traceable or complete record.[74] INGAA also provided examples of records that they believed to be acceptable, and requested that PHMSA includes these examples in the final preamble.

Several commenters also opposed the proposed Appendix A to part 192 that summarizes the records requirements within part 192 and requested that it be eliminated, stating that Appendix A goes beyond summarizing the existing records requirements and introduces several new recordkeeping requirements and retention times. Commenters also asserted that Appendix A should not be retroactive. Some commenters supported the inclusion of Appendix A, saying that it is a much-needed clarification of record requirements and retention. Noting that the title of Appendix A suggests that it is specific to gas transmission lines but that it does include some record retention intervals for distribution lines, NAPSR recommended that Appendix A be expanded to include records and retention intervals for all types of pipelines. Many commenters requested that PHMSA clarify that the proposed changes to Appendix A apply only to gas transmission lines.

Some commenters also opposed the newly proposed recordkeeping requirements for pipeline components at § 192.205. Commenters, including Dominion East Ohio, stated that PHMSA should exclude pipeline components less than 2 inches in diameter, as these small

[74] https://www.phmsa.dot.gov/regulations-fr/notices/2012-10866; 77 FR 26822; May 7, 2012, "Pipeline Safety: Verification of Records."

components are often purchased in bulk with pressure ratings and manufacturing specifications only printed on the component or box. They further stated that in doing this, PHMSA would be consistent with its proposed material properties verification requirements. Another commenter stated that these requirements should be eliminated because they are duplicative of the current requirements for establishing and documenting MAOP at § 192.619(a)(1).

Some commenters also opposed the proposed recordkeeping requirements regarding qualifications of welders and welding operators and qualifying persons to make joints in §§ 192.227 and 192.285, stating that keeping these records for the life of the pipeline is not needed, nor are they necessary for the establishment of MAOP.

Issues related to records were discussed during all of the GPAC meetings in various capacities. At the meeting in January 2017, several issues were discussed, including: broad records guidance in a general duties clause might be a good idea in theory but might cause unintended consequences, and they discussed the advisability of addressing necessary record components individually in the context of specific code sections.

The GPAC discussed the proposed addition of "reliable" to the phrase "traceable, verifiable, and complete" (TVC) record in the proposed rule. The "TVC" standard was recommended by the NTSB following the PG&E incident. Changing that standard could potentially derail work being done by operators to meet that traceable, verifiable, and complete record standard.

The GPAC also discussed PHMSA's statutory authority to impose the proposed recordkeeping requirements, even in subparts that are retroactive, because PHMSA is not requiring particular types of design, installation, construction, etc., but is requiring that operators keep records relevant to current operation.

At the GPAC meeting on June 6, 2017, the GPAC discussed the proposed recordkeeping requirements for the qualification of welders and welding operators as well as the qualification of persons making joints on plastic pipe systems. Specifically, the discussion revolved around whether the recordkeeping requirements should be for the life of the pipeline, as proposed in the NPRM, or whether it should be for 5 years. Certain members believed it should be a 5-year requirement to be consistent with other operator qualification requirements, and other members believed that a 5-year requirement would be adequate due to the "bathtub curve" phenomenon where pipelines are more likely to fail early or late in their service history. Therefore, having the records for welding qualification within that early period would be sufficient.

Following that discussion, the committee recommended that PHMSA modify the proposed rule to delete the word "reliable" from the records standard to now read "traceable, verifiable, and complete" wherever that standard is used; clarify that documentation be required to substantiate the current class location under § 192.5(d); and modify the recordkeeping provisions related to the qualification of welders and the qualification of persons joining plastic pipe to include an effective date and change the retention period of the necessary records to 5 years.

At the March 2, 2018, meeting, the GPAC recommended that PHMSA withdraw the general duty recordkeeping requirement at § 192.13(e) and Appendix A; modify the recordkeeping requirements for pipeline components to clarify they apply to components greater than 2 inches in nominal diameter; and revise the requirements related to material, pipe design, and pipeline component records to clarify the effective date of the requirements.

At the meeting on March 27, 2018, the GPAC recommended that PHMSA provide guidance in the preamble regarding what constitutes a traceable, verifiable, and complete record.

Further, the GPAC recommended PHMSA clarify that the MAOP recordkeeping requirements in the MAOP establishment section at § 192.619(f) apply only to onshore, steel, gas transmission pipelines, and that they only apply to the records needed to demonstrate compliance with paragraphs (a) through (d) of the section. The GPAC suggested PHMSA could remove examples of acceptable MAOP documents from the rule and include that listing in the preamble of the final rule and through guidance materials.

The GPAC also recommended that PHMSA clarify that the MAOP recordkeeping requirements are not retroactive, that existing records on pipelines installed prior to the rule must be retained for the life of the pipeline, that pipelines constructed after the effective date of the rule must make and retain the appropriate records for the life of the pipeline, and that MAOP records would be required for any pipeline placed into service after the effective date of the rule. Further, the GPAC recommended PHMSA revise the rule by changing other sections, including §§ 192.624 and 192.917, to require when and for which pipeline segments missing MAOP records would need to be verified in accordance with the MAOP reconfirmation and material properties verification requirements of the rulemaking.

3. PHMSA Response

PHMSA appreciates the information provided by the commenters regarding the proposed records requirements. After considering these comments and as recommended by the GPAC, PHMSA is modifying the rule to withdraw the proposed § 192.13(e) and Appendix A to avoid possible confusion regarding recordkeeping requirements. Also, whenever new recordkeeping requirements are included, PHMSA modified the rule to clarify that the new requirements are not retroactive. To the degree that operators already have such records, they must retain them. Operators must retain records created while performing future activities required by the code.

In addition to these general modifications, with regard to specific records requirements, PHMSA is modifying the rule as follows: (1) In § 192.5(d), operators must retain records documenting the current class location (but not historical class locations that no longer apply because PHMSA agrees they are not necessary). (2) In § 192.67, the rule is being modified to delete reference to "original steel pipe manufacturing records" to avoid retroactivity concerns, add wall thickness and seam type to clarify that this manufacturing information must be recorded, and include an effective date to eliminate retroactivity concerns. (3) In § 192.205, records for components are only required for components greater than 2 inches (instead of greater than or equal to 2 inches) (see Section III(A)(i)(3)). (4) In § 192.227, records demonstrating each individual welder qualification must be retained for a minimum of 5 years because PHMSA believes 5 years of welder qualification records are sufficient to evaluate whether systemic issues are present upon inspection and at the start-up of the pipeline. (5) In § 192.285, records demonstrating plastic pipe joining qualifications at the time of pipeline installation in accordance must be retained for a minimum of 5 years because PHMSA believes 5 years of records are sufficient to evaluate whether systemic issues are present upon inspection and at the start-up of the pipeline. (6) In § 192.619, PHMSA clarified that new recordkeeping for MAOP only apply to onshore, steel, gas transmission pipelines. In addition, PHMSA deleted the sentence with examples of records that establish the pipeline MAOP, which include, but are not limited to, design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data to prevent redundancies in the regulations as this list is maintained in § 192.607.

PHMSA notes that the recordkeeping requirements in this final rule under §§ 192.67, 192.127, 192.205, and 192.227(c) applicable to gas transmission pipelines will apply to offshore gathering pipelines and Type A gathering pipelines as well. In accordance with this final rule's requirements, operators of such pipelines must keep any of the pertinent records they have upon this rule's issuance, and they must retain any records made when complying with these requirements following the publication of this rule. PHMSA notes that the requirements for creating records in §§ 192.67, 192.127, 192.205, and 192.227(c) are forward-looking requirements. However, and in accordance with this final rule, operators must retain any records they currently have for their pipelines. Any records generated through the course of operation, including, most notably, records generated by the material properties verification process at § 192.607, must also be retained by operators for the life of the pipeline.

As requested by the GPAC, PHMSA considered moving § 192.619(e) to be a subsection of § 192.619(a) and considered referencing § 192.624 in § 192.619(a). However, PHMSA is retaining the proposed paragraph (e) in the final rule and the reference to § 192.624 within § 192.619(e) because it more clearly requires pipeline segments that meet any of the applicability criteria in § 192.624(a) must reconfirm MAOP in accordance with § 192.624, even if they comply with § 192.619(a) through (d). This also avoids the potential for conflict if this requirement were to be placed in a paragraph that applies to gathering lines and distribution lines. It also makes it clear that pipeline segments with MAOP reconfirmed under § 192.624 are not required to comply with § 192.619(a) through (d).

Lastly, throughout this final rule, PHMSA is deleting the word "reliable" from the records standard to now read "traceable, verifiable, and complete" wherever that description is used. PHMSA issued advisory bulletins ADB 12-06 on May 7, 2012 (77 FR 26822) and ADB

11-01 on January 10, 2011 (76 FR 1504). In these advisory bulletins, PHMSA provided clarification and guidance that all documents are not records and provided additional information on the definition and standard for records. For a document to be a record, it must be traceable, verifiable, and complete. PHMSA provides further explanation of these concepts below.

Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, which include mechanical and chemical properties; purchase requisition; or as-built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.

Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a pipeline segment complemented by pressure charts or field logs. Another example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipeline segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by a qualified individual who observed the test or inspection being performed.

Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking such as a corporate stamp or seal. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipeline segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.

For example, a mill test report must be traceable, verifiable, and complete, which is a typical record for pipelines. For the mill test report to be traceable it would need to be dated in the same time frame as construction or have some other link relating the mill record to the material installed in the pipeline, such as a work order or project identification. For the mill test report to be verified, it would need to be confirmed by the purchase or project specification for the pipeline or the alignment sheet with consistent information. Such an example would be verified by independent records. For the mill test report to be complete, it must be signed, stamped, or otherwise authenticated as a genuine and true record of the material by the source of the record or information, in this example it could be the pipe mill, supplier, or testing lab.

Another common record is a pressure test record, which must be traceable, verifiable, and complete. For the pressure test record to be traceable, it would need to identify a specific and unique segment of pipe that was tested (such as mileposts, survey stations, etc.) or have some other link relating the pressure test to the physical location of the test segment, such as a work order, project identification, or alignment sheet. For the pressure test record to be verified, it would need to be confirmed by the purchase or project specification for the pipeline or the alignment sheet with consistent information. Such an example would be verified by independent records. For the pressure test record to be complete, it should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, elevation information, and any other information required by § 192.517, as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test.

I. Miscellaneous Issues

iii. – Cost/benefit Analysis, Information Collection, and Environmental Impact Issues

NPRM Assumptions / Proposals

U.S. Code, title 49, chapter 601, section 60102 specifies that the U.S. Department of Transportation (U.S. DOT), when prescribing any pipeline safety standard, shall consider relevant available gas and hazardous liquid pipeline safety information, environmental information, the appropriateness of the standard, and the reasonableness of the standard. In addition, the U.S. DOT must, based on a risk assessment, evaluate the reasonably identifiable or estimated benefits and costs expected to result from implementation or compliance with the standard. PHMSA prepared a preliminary regulatory impact analysis (PRIA) to fulfill this statutory requirement for the proposed rule and a new regulatory impact analysis (RIA) for this final rule. In addition, PHMSA's Environmental Assessment (EA) is prepared in accordance with NEPA, as amended, and the Council on Environmental Quality (CEQ) regulations for implementing NEPA (40 CFR parts 1500-1508). When an agency anticipates that a proposed action will not have significant environmental effects, the CEQ regulations provide for the preparation of an EA to determine whether to prepare an environmental impact statement or finding of no significant impact.

Summary of Public Comment

Cost Impacts

Several commenters provided input on the cost analysis conducted in the PRIA, providing comments on the structure, assumptions, and unit costs in the PRIA as well as on the lack of accounting for impacts such as the abandonment of pipelines and the cost increase to electricity ratepayers.

Some public interest groups provided input on the cost analysis in the PRIA. EDF stated that the PRIA reasonably addressed uncertainty and lack of information surrounding certain key data assumptions. EDF further stated that the PRIA aligned with Office of Management and Budget guidance on the development of regulatory analysis for rulemakings. They stated that PHMSA used conservative values when making best professional judgments. PST asserted that the costs included in the PRIA for reconfirmation of MAOP, data gathering, record maintenance, and data integration for lines subject to the IM provisions result from the current IM regulations and practices and should not be attributed to this rulemaking. They further stated that the PRIA should be amended to remove these costs related to lines within HCAs.

Several trade associations and industry pipeline entities provided input on the assumptions, methodology, and unit costs used in the PRIA, stating that PHMSA underestimated the cost of complying with the proposed regulations. AGA stated that the organization of the PRIA by "topic areas" made it difficult to evaluate the cost estimates of the various provisions of the rule and requested that PHMSA provide a RIA with the final rule that addresses each regulatory section as organized in the preamble. Many commenters, including INGAA, AGA, AGL Resources, and Piedmont, stated that the PRIA underestimated the cost impacts of increased material properties verification, recordkeeping, and MAOP reconfirmation requirements. AGL Resources asserted that complying with the proposed record requirements would involve increased labor and investment costs that should be quantified in the final RIA. AGA stated that it was unclear whether or how the PRIA incorporated material properties verification costs related to material documentation, plan creation, revisions, and testing. NYSEG asserted that the PRIA underestimated the cost impact of the proposed rule on smaller local distribution companies with combined transmission and distribution systems and estimated that they would have to perform IM elements on 8 times the mileage currently in their IM program. Lastly, INGAA provided a higher cost for MAOP confirmation than was estimated in the PRIA due in large part to their assumption that industry would continue to rely on pressure testing, as they asserted that the proposed methods for ILI and ECA are not feasible.

INGAA, AGA, and API submitted detailed cost analyses to the rulemaking docket, while many other commenters (approximately 40) provided estimated unit costs for various provisions of the proposed rule that were generally higher than the unit costs used in the PRIA. For example, Southwest Gas stated that the costs included in the PRIA for options such as ILI and pressure testing were not representative of the costs to their system. With regard to the cost of integrity assessments, BG&E stated that it would cost them over $1 million per year to perform integrity assessments on the additional 100 miles of MCA transmission pipelines, a total which equates to a higher cost per mile estimate than was used in the PRIA. Additionally, New Mexico Gas Co. stated that the proposed rule would cost their company $5.6 million per year to perform integrity assessments on 528 miles of MCA transmission pipe. Vectren estimated the impact to its transmission system would cost $22 million annually. Lastly, PG&E stated that their forecasted costs to implement the proposed rule are significantly higher than the estimates in the

PRIA. PG&E provided a comparison of the PRIA costs with their expected expenditures to comply with many provisions in the proposed rule. They projected the cost of compliance would require an upfront investment of $578 million in addition to $222 million per year (as well as a reoccurring cost of $30 million every 7 years) and stated that, comparatively, the PRIA estimates a present value annualized cost of $47 million per year.

Some stakeholders provided input on the estimated number of miles that PHMSA used to determine the regulatory impact of the provisions in the proposed rule. For example, INGAA stated that it assumed the mileage estimated by PHMSA for estimation of MAOP confirmation, material properties verification, and integrity assessments outside HCAs to be accurate with the addition of reportable in-service incidents since last pressure test data. INGAA also asserted that the mileage estimated for MCA transmission pipes should be done on the per-foot basis instead of on the per-mile basis because these pipes are likely to be an aggregation of short pipeline segments that are 1 mile or shorter in length. The North Dakota Petroleum Council asserted that proposed changes in the definition of onshore gathering lines would dramatically increase the number of miles of regulated gathering wells beyond the mileage estimates in the PRIA.

Some commenters asserted that the financial impact of the proposed rule would be immense and that, because operators would not be able to bear these costs alone, they would likely pass the costs on to the ratepayers. For example, APGA stated that all of their member utilities purchase gas and pay transportation charges to transmission pipelines to deliver gas from the producer to the utility. They asserted that ratepayers would pay for the costs that would be incurred by their transmission suppliers to comply with this rule. Similarly, Indiana Utility Regulatory Commission requested that PHMSA consider the costs to ratepayers in its cost analysis. Other commenters stated that this rule could force operators to take significant portions of their pipelines out of service while they are brought into compliance and that the PRIA failed to recognize that FERC requires interstate natural gas pipelines operators to provide demand charge credits to customers when service is disrupted.

Some commenters stated that the proposed rule may cause pipeline abandonment and that these impacts should be considered in the final RIA. Boardwalk Pipeline stated that if a pipe is no longer economic to operate, but FERC does not grant abandonment authority, a pipeline company would be forced to either operate a pipeline that may not meet PHMSA standards or undertake expensive replacement projects. Boardwalk Pipeline further stated that while operators may seek to recover the costs of replacement projects through rate increases, in a competitive pipeline market where operators are forced to discount their pipeline rates in order to retain customers, these costs might be too great to recover. Similarly, the Independent Petroleum Association of America stated that the PRIA failed to account for the costs that could be incurred by operators if pipeline infrastructure is abandoned because the cost that would be required to comply with the rule would necessitate this abandonment. The Public Service Commission of West Virginia suggested that, should operators abandon wells and pipelines due to the requirements of this proposed rule, it could cause an environmental and economic liability for State regulators if operators abandon wells and pipelines without proper clean up.

Several commenters expressed concern that PHMSA's cost-benefit analysis does not meet the requirements established by the 2011 Pipeline Safety Act and the Administrative Procedures Act (APA). Trade associations stated that the PRIA does not fulfill PHMSA's statutory obligations because it omits relevant costs, relies on incorrect assumptions, and contains multiple inconsistencies. INGAA asserted that the PRIA does not comply with the APA because the finding in the PRIA that the proposed benefits outweigh the costs is contingent on an underestimation of the costs of the proposed rule. INGAA also noted that flawed cost-benefit analysis can be grounds for courts to reject agency rulemakings. INGAA asserted that the proposed rulemaking does not comply with the Paperwork Reduction Act (PRA), because PHMSA's estimate of the information collection burden did not include the costs of these additional recordkeeping requirements for transmission pipeline operators.

Benefit Estimates

PHMSA also received comments on the benefits associated with the proposed rule. Physicians for Social Responsibility expressed their support of the proposed rule and the analysis of reduced accidents and increased worker safety in the PRIA. Additionally, Physicians for Social Responsibility stated that many harmful air pollutants, such as nitrous oxide, sulfur dioxide, particulate matter, formaldehyde, and lead, are all associated with gas pipelines and compressor stations. They further stated that this rule would help reduce or mitigate this pollution and that these public health benefits should be accounted for in the benefits calculations.

Other commenters, including AGA and INGAA, stated that PHMSA overestimated the damage caused by incidents in the quantification of benefits in the PRIA. AGA stated that PHMSA allowed one major incident to skew the data in their benefits analysis and proposed that PHMSA adopt a new approach to quantify the benefits of reduced accidents. INGAA stated that using data from the past 13 years skewed the results and that the most recent 5 years of incident history would more reasonably reflect positive developments in pipeline safety, given that significant developments in pipeline safety have occurred within this time period.

Several commenters provided input on the proposed use of the social cost of carbon and the social cost of methane in the PRIA. EDF and National Resource Defense Council supported the use of the social costs of carbon and methane methodology in the PRIA. However, these commenters stated that the estimates for social costs of carbon and methane were likely too conservative and that the values should be higher than those used in the PRIA. These commenters stated that PHMSA should encourage the Interagency Working Group on Social Cost of Carbon to update regularly the social cost of carbon and social cost of methane as new economic and scientific information emerges. API stated that the proposed use of the social cost of methane to calculate the benefits of emissions reductions was flawed due to the discount rates used by PHMSA. They asserted that PHMSA used low discount rates that led to a liberal damage estimate. In addition, API and Industrial Energy Consumers of America asserted that the social cost of carbon values used by PHMSA inappropriately impose global carbon costs on domestic manufacturers, which damages the industry's ability to compete internationally. AGA stated that the process used to develop the social cost of methane values in the PRIA did not undergo sufficient expert and peer review. INGAA stated that PHMSA overestimated the amount of greenhouse gas emissions that the rule would reduce.

Environmental Impacts

Several commenters noted that the 2011 Pipeline Safety Act mandates that PHMSA consider the environmental impacts of proposed safety standards. Citizen groups stated that the proposed regulation fulfills this statutory obligation and is a step forward in reducing methane emissions from natural gas pipelines. Multiple citizen groups emphasized the consequences of climate change, the high global warming potential of methane, and the responsibility of natural gas systems for a significant portion of U.S. methane emissions. Citizen groups underlined the importance of regulating methane leaks and considering methane's climate implications in natural gas regulations. The Lebanon Pipeline Awareness Group addressed local environmental impacts, requesting that pipelines not be permitted to contaminate agricultural soils.

Trade associations asserted that PHMSA did not fulfill its statutory obligation to consider the full environmental impacts of the proposed safety standards, suggesting that PHMSA failed to consider several topics in the NPRM that would have direct environmental impacts. These commenters claimed that certain topics and their impacts, including IM clarifications, MAOP reconfirmation, and hydrostatic pressure testing, were mischaracterized in the EA, and that PHMSA further underestimated the number of excavations that would need to be made per the proposal as well as the impacts of procuring and disposing of water for hydrostatic tests.

Trade associations further expressed concerns that, while PHMSA had addressed the emissions avoided under the proposed rule, PHMSA had not addressed the extent to which the proposed rule would increase emissions. AGA and INGAA noted that operators need to purge lines of natural gas before conducting hydrostatic tests or removing pipelines from service for replacement or repair. These commenters stated that the proposed regulation would increase methane emissions by increasing the number of hydrostatic tests, pipeline replacements, and pipeline repairs required and asserted that the EA did not take the increased emissions from these blowdowns into account. INGAA asserted that not considering these methane emissions constituted a violation of the 2011 Pipeline Safety Act and failure to "engage in reasoned decision making." INGAA also suggested that the methane emissions resulting from this rulemaking would run counter to President Obama's goals of reducing methane emissions.

EDF and PST commissioned a study from M.J. Bradley & Associates (MJB&A) that calculated the extent to which the proposed rule would result in blowdown emissions. MJB&A found that potential methane emissions resultant from the proposed rule would increase annual methane emissions from natural gas transmission systems by less than 0.1 percent and increase annual methane emissions from transmission system routine maintenance by less than one percent. MJB&A also noted five mitigation methods that if implemented, could decrease blowdown emissions by 50 to 90 percent.[75] MBJ&A calculated that the societal benefits of methane reduction outweighed the mitigation costs for all mitigation options considered. Based on this study, EDF asserted that while the marginal increase in emissions from the proposed rule would be small, the total emissions from blowdowns would nonetheless be significant. They stated that PHMSA should require operators to select and implement one of the mitigation options and report to PHMSA information about their blowdown events, such as the mitigation option selected and the amount of product lost due to blowdowns required by the proposed rule. EDF also stated that if operators do not mitigate blowdown emissions, they should be required to provide an engineering or economic analysis demonstrating why mitigation is deemed infeasible or unsafe.

AGA stated that the EA did not address other environmental impacts resultant from hydrostatic pressure testing. AGA noted two anticipated water-related impacts: (1) hydrostatic pressure testing's water demand could aggravate water scarcity in already water-scarce environments, and (2), the water used in hydrostatic tests could introduce contaminants if disposed on-site (or be very expensive to transport to off-site disposal). AGA explained that

[75] The methods are 1) gas flaring; 2) pressure reduction prior to blowdown with inline compressors; 3) pressure reduction prior to blowdown with mobile compressors; 4) transfer of gas to a low-pressure system; and 5) reducing the length of pipe requiring blowdown by using stopples.

wastewater from hydrostatic tests could include hydrocarbon liquids and solids, chlorine, and metals.

AGA also asserted that the EA did not adequately consider the land disturbances that could result from the proposed hydrostatic testing requirements, nor did it consider that performing inline inspections and modifying pipelines to accommodate inline inspection tools would generate waste and disturb natural lands. AGA explained that operators must clean pipelines prior to conducting inline inspections or modifying pipelines for inline inspection tools and that this cleaning could produce large volumes of pipeline liquids, mill scale, oil, and other debris. AGA expressed concerns that the proposed EA did not discuss these environmental impacts associated with requiring MAOP confirmation, given that PHMSA anticipates that most affected pipelines would verify MAOP using ILI and pressure testing.

AGA also provided input on the local environmental impacts of the proposed increased testing and inspection. AGA expressed concerns that the EA had (1), underestimated the quantity of excavations that would be required under the proposed rule, and (2), inadequately assessed the environmental impacts of those excavations. AGA asserted that the EA had insufficiently considered the extent to which more excavations would generate water and soil waste. AGA also suggested that the proposed rule may induce operators to modify or replace pipelines and that these modifications and replacements may affect land beyond existing rights of way. AGA asserted that this additional land area should be considered in the EA.

Trade associations raised other technical issues regarding the EA. AGA expressed concerns that PHMSA provided insufficient information about methods used to calculate values in the EA and that this insufficient documentation interfered with stakeholders' ability to provide comments on the values that PHMSA chose. INGAA asserted that the proposed rule fell short of several legal obligations under NEPA, stating that the EA does not provide the required "hard look" at environmental impacts, that the EA does not adequately discuss the indirect and cumulative effects of the proposed rule, and that the purpose and need statement in the EA do not fulfill NEPA instructions. INGAA also expressed concern that PHMSA did not consider sufficient regulatory alternatives, stating that the EA considered solely the proposed rule, one regulatory alternative, and the no action alternative. INGAA stated that given the many provisions of the proposed rule, this approach was too limited.

Other Impacts

Some trade associations and pipeline industry entities provided input that the PRIA failed to account for the indirect effects of operators shifting resources to comply with the proposed rule. For example, AGA stated that the PRIA did not consider the potential indirect impacts the rule might impose on distribution lines. They asserted that the magnitude and prescriptiveness of the proposed rule would require distribution companies with intrastate transmission and distribution assets to reassign their limited resources to transmission lines.

Some commenters stated that PHMSA did not consider that the proposed rule would divert resources away from voluntary safety programs their companies are initiating, stating that these voluntary safety measures would be scaled back because of the proposed rule. For example, AGA stated that accelerated pipe replacement programs that replace aging cast iron, unprotected steel pipe, and vintage plastic pipe, would lose resources as operators shift staff and capital to comply with the proposed rule. They further asserted that failing to replace these pipes would delay reductions in methane emissions from old, leaky pipes.

PHMSA Response

Cost Impacts

PHMSA has reviewed the comments related to the RIA for the proposed rule and has revised the final analysis consistent with the final rule and in consideration of the comments. PHMSA addressed the comments received on the RIA in two key ways. First, PHMSA revised many of the requirements in the final rule, including (a) revising or clarifying that the final provisions do not apply to gas distribution or gas gathering pipelines; (b) revising MAOP reconfirmation requirements for grandfathered pipelines to include only those lines with MAOP greater than or equal to 30 percent SMYS; (c) streamlining the process for operators to use an alternative technology for MAOP reconfirmation; (d) removing the term "occupied sites" in the MCA definition; and (e) revising the records provisions to remove certain proposed provisions and clarifying that the new requirements are not retroactive. These changes, as well as others made in the final rule, result in less costly and more cost-effective requirements. Second, in response to comments received, PHMSA made several revisions to the analysis conducted in the RIA for the proposed rule, discussed below. Also, in response to comments, PHMSA revised the final RIA to align more closely to the preamble organization.

PHMSA acknowledges the baseline issues associated with establishing MAOP, data collection, and other provisions noted in the comments. In the final RIA, PHMSA is including estimated incremental costs to reconfirm MAOP for lines within HCAs based on a current compliance baseline. Attributing compliance to existing pipeline safety regulations would reduce both the costs and benefits of the final rule. Regarding the comments that the RIA for the proposed rule underestimated the cost impacts of material properties verification, recordkeeping, and MAOP confirmation, as discussed above, the changes to the scope and applicability of the

MAOP reconfirmation, data, and recordkeeping provisions result in common-sense, cost-effective requirements. For example, PHSMA designed the final requirements for material properties verification to allow operators the option of a sampling program that opportunistically takes advantage of repairs and replacement projects to verify material properties simultaneously. The final provisions allow, over time, operators to collect enough information to gain significant confidence in the material properties of pipe subject to this requirement.

Further, as discussed under the section regarding the material properties verification process, the final rule removes the applicability criteria of the material properties verification requirements and makes a procedure for obtaining pipeline physical properties and attributes that are not documented in traceable, verifiable, and complete records or for otherwise verifying pipeline attributes when required by MAOP reconfirmation requirements, IM requirements, repair requirements, or other code sections. Therefore, due to the changes made from the proposed rule, the material properties verification requirements mandated by section 23 of the 2011 Pipeline Safety Act represent a cost savings in comparison to existing regulations, although PHMSA has not quantified those savings.

With regard to the operator-provided cost information or estimates of the proposed rule, the commenters' estimates were not transparent enough for PHMSA to discern the assumptions and inputs underlying the estimates. As a result, PHMSA could not reliably confirm whether the cost information accurately reflected the quantity and character of the actions required by the proposed rule. To improve the transparency of the analysis and address commenters' concerns about PHMSA's reliance on best professional judgment in the RIA for the proposed rule, PHMSA contacted five vendors of pipeline inspection and testing services to obtain updated cost estimates for several unit costs that were based on best professional judgement in the RIA for the proposed rule. These vendors provided representative incremental costs associated with the final rule requirements. In the final RIA, PHMSA used prices provided by vendors to estimate unit costs for all MAOP reconfirmation and integrity assessment methods, as well as for upgrades to launchers and receivers.

Regarding MAOP reconfirmation specifically, in the RIA for the proposed rule PHMSA assumed operators would conduct MAOP reconfirmation using either pressure testing or ILI. In the final RIA, based on feedback received during a GPAC meeting[76], PHMSA assumed that operators would reconfirm MAOP using a mix of all six available compliance methods.

Additionally, in the final RIA, PHMSA analyzed the requirements for MAOP reconfirmation and integrity assessments outside HCAs for each operator individually based on the information they submitted in their Annual Reports. Based on the information in operator Annual Reports and the final rule requirements for MAOP reconfirmation, some operators will incur less of an impact than indicated by their public comments.

Regarding the comment that the proposed changes to the definition of onshore gathering lines would dramatically increase the number of miles of regulated gathering wells beyond the mileage estimates in the RIA for the proposed rule, this final rule does not change the definition of gathering pipelines.

With respect to pipelines located within MCAs, PHMSA confirmed the analysis of the length of gas transmission pipelines located within MCAs in the RIA for the proposed rule by integrating additional spatial data from the U.S. Census Bureau, U.S. Geological Survey, Environmental Systems Research Institute, and Tele-Atlas North America, Inc. For additional details on the MCA GIS analysis, see section 5.7 of the RIA for the final rule. This allowed

[76] GPAC Meeting, March 26-28, 2018. For a transcript of the meeting, see https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=970

PHMSA to confirm the number of impacted miles. Additionally, due to existing state MAOP reconfirmation requirements, PHMSA updated the RIA to reflect that impacts in California are not attributable to the rule. Lastly, PHMSA presented all impacted mileage on a dollar-per-foot basis instead of dollars per mile, based on comments received that these pipeline segments are likely to be an aggregation of short pipeline segments that are a mile or shorter in length.

Regarding the comment that PHMSA underestimated the cost impact of the proposed rule on smaller local distribution companies with combined gas transmission and gas distribution systems, PHMSA conducted an analysis of the rule's impact on small entities by comparing entity-level cost estimates to annual entity revenues and identifying entities for which annualized costs may exceed 1 percent and 3 percent of revenue. As documented in the final Regulatory Flexibility Act (FRFA) analysis, PHMSA relied on conservative assumptions in performing this sales test, which may overstate, rather than understate, compliance costs for small entities. PHMSA found that the final rule will not have a significant economic impact on small entities.

PHMSA does not agree that the final rule requirements constitute a significant energy action. PHMSA agrees with the comment that the costs would be passed on to ratepayers; however, PHMSA disagrees that these costs would be immense. E.O. 13211 requires agencies to prepare a Statement of Energy Effects when undertaking certain agency actions if, among other criteria, the regulation is expected to see an increase in the cost of energy production or distribution in excess of one percent. The annualized cost of these requirements represents less than 0.1 percent of pipeline transportation of natural gas (North American Industry Classification System code 486210) industry revenues ($25 billion), adjusting the 2012 Economic Census value into 2017 dollars using the Gross Domestic Product Implicit Price Deflator Index.

Therefore, in the aggregate it is extremely unlikely that these requirements would cause a significant increase in costs that utilities would pass on to the ratepayer.

Available information supports that, in the baseline, operators are replacing or abandoning certain pipelines regardless of the implementation of this rule as well as taking other actions such as making lines piggable.[77] As discussed above, in the final RIA, PHMSA assumed some use of pipe replacement and abandonment as a means of operators reconfirming MAOP. However, the costs of replacing infrastructure operating beyond the design useful life are not attributable to safety regulations and investment in plant, including a return on investment, are already recovered through rates.

The RIA for the final rule meets all PHMSA's requirements under applicable acts and executive orders. The analysis involves estimating a baseline scenario and changes under the regulation. PHMSA has used its judgement, available data, information, and analytical methods to develop an analysis of the baseline and incremental costs and benefits under the rule. As discussed above, some costs and benefits may be attributable to existing requirements and some may occur in the absence of the rule.

Benefits Estimates

PHMSA agrees that recent data is more reflective of recent improvements in pipeline safety and performance relative to current standards. For the final RIA, PHMSA used more recent data on pipeline incidents from 2010 to 2017 versus the 2003 to 2015 data used in the RIA

[77] PG&E. 2011. "Pacific Gas And Electric Company's Natural Gas Transmission Pipeline Replacement Or Testing Implementation Plan." California Public Utilities Commission; Consolidated Edison Company Of New York. 2016. "Consolidated Edison Company Of New York, Inc. 2017-2019 Gas Operations Capital Programs/Projects." New York State Department of Public Service. http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-G-0061&submit=Search.

for the proposed rule. PHMSA used the data from 2010 on because PHMSA updated its incident reporting methodology in 2010, and this period therefore provides the largest available sample of consistently reported incident data. Regarding the benefits analysis for the preliminary RIA developed for the NPRM potentially being skewed by one major incident (the PG&E incident at San Bruno), there is no evidence that more serious incidents are not possible in the future in the absence of the regulation, and therefore, PHMSA does not exclude this incident when qualitatively assessing benefits. At the same time, and although PHMSA developed this rule to prevent future, similar incidents, PHMSA cannot know with certainty whether a similar incident would occur again absent this rulemaking. According to the historical record, serious incidents, like the one occurring at San Bruno, occur approximately once per decade. For example, on August 19, 2000, a 30-inch-diameter natural gas transmission pipeline operated by the El Paso Natural Gas Company ruptured adjacent to the Pecos River near Carlsbad, NM. The released gas ignited and burned for 55 minutes. Twelve persons camping near the incident location were killed, and their three vehicles were destroyed.[78] Similarly, on March 23, 1994, a 36-inch-diameter natural gas transmission pipeline owned and operated by Texas Eastern Transmission Corporation ruptured in Ellison Township, NJ. The incident caused at least $25 million in damages, dozens of injuries, and the evacuation of hundreds.[79] More detailed data on current pipeline integrity in relation to populations and the environment would enable more detailed predictions of the benefits of regulations.

Due to the speculative nature of predicting the occurrence, avoidance, and character of specific future pipeline incidents, in the final RIA, PHMSA elected not to quantify the rule's

[78] Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico, August 19, 2000, Pipeline Accident Report, NTSB/PAR-03/01, Washington, D.C.
[79] Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Pipeline Accident Report, NTSB/PAR-95-01, Washington, D.C.

benefits. PHMSA uses this approach rather than make highly uncertain predictions about both a specific number of future incidents avoided due to the final rule, and the character of avoided incidents with respect to effects on benefit-analysis endpoints (e.g., fatalities, injuries, evacuation). The quantified benefits for each provision therefore represent the quantity of a given benefit category required to achieve a dollar value equal to the provision's compliance cost.

PHMSA does not have data on harmful air pollutants such as nitrous oxide, sulfur dioxide, particulate matter, formaldehyde, and lead associated with gas pipelines and compressor stations, or the reductions in these pollutants under the rule. Therefore, the analysis did not address the environmental costs associated with these pollutants. PHMSA did not include estimates of benefits based on the social cost of methane for the final rule.

Environmental Impacts

Regarding the comments stating that the preliminary EA did not adequately consider the air emissions that would result from hydrostatic pressure testing, inline inspections, excavations, and MAOP reconfirmation, PHMSA revised the EA to address this issue. Commenters asserted that by increasing the number of hydrostatic tests, pipeline replacements, and pipeline repairs required, the proposed provisions would increase methane "blowdown" emissions that result from the required purging of natural gas pipelines before conducting these actions. PHMSA revised the EA to include a discussion of the study conducted by M.J. Bradley & Associates (MJB&A)[80] that calculated the extent to which the proposed rule would result in blowdown emissions.

[80] The study was commissioned by EDF and PST and is available at http://blogs.edf.org/energyexchange/files/2016/07/PHMSA-Blowdown-Analysis-FINAL.pdf

MJB&A found that unmitigated blowdown from the miles of transmission pipeline that would be required to conduct a MAOP determination would release an average of 1,353 metric tons per year of methane to the atmosphere for the 15-year compliance period[81] proposed by PHMSA. By comparison, historical unintentional releases from natural gas transmission pipelines outside of HCAs with piggable lines greater than 30 percent SMYS (a universe of facilities that could be subject to MAOP reconfirmation in MCAs) averaged 13,500 metric tons per year from 2010 to 2017. These releases were caused by 163 incidents that released an average of 663.4 metric tons per incident[82].

Therefore, if the final rule requirements avoided two average incidents per year, the rule would not result in any net methane releases. MJB&A further stated that the potential methane emissions resultant from the NPRM would increase annual methane emissions from natural gas transmission systems by less than 0.1 percent and increase annual methane emissions from transmission system routine maintenance/upsets by less than one percent. Given these factors, PHMSA does not believe that the final rule will result in a significant, if any, increase in methane releases.

In response to comments, PHMSA revised the EA to also include a discussion of water-related impacts resulting from hydrostatic pressure testing as well as waste generation land disturbances from hydrostatic pressure testing and inline inspections. Operators must conduct all waste and wastewater disposal activities in accordance with federal, state, and local regulations and permit requirements, and the final rule requires processes and procedures in which pipeline operators are already familiar with respect to pipeline IM. Regarding the comments on the

[81] See § 192.624(b)
[82] "Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data." Phmsa.Dot.Gov. 2017. https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data

environmental impacts of pipe replacement, as discussed above, the impacts of replacing infrastructure that is operating beyond the design useful life are not attributable to the final rule requirements. While the final RIA assumes that operators will comply with MAOP reconfirmation using pipe replacement for approximately 300 miles of pipe, PHMSA did not consider these replacements to be incremental costs. Similarly, the environmental impacts are not attributable to the final rule requirements.

Other Impacts

PHMSA disagrees with the analysis of operators shifting resources away from safety programs to comply with the proposed rule. PHMSA has revised and clarified the pipeline safety and integrity applicability of the final rule such that many operators will incur lower costs than previously anticipated. The final rule also provides long compliance schedules to enable planning for efficient compliance actions.

IV. GPAC Recommendations

This section briefly summarizes the NPRM proposals, the GPAC's major comments on the proposals discussed, and the recommendations of the committee regarding how those provisions should be finalized. More detail, the presentations, and the transcripts from all of the meetings are available in the docket for this rulemaking.[83] The provisions, which are presented in the order they were discussed at the GPAC meetings, the changes the committee agreed upon, and the corresponding vote counts are as follows:

[83] https://www.regulations.gov/docket?D=PHMSA-2011-0023

6-Month Grace Period for 7-Calendar-Year Reassessment Intervals (§ 192.939(b)):

In the NPRM, PHMSA proposed to allow operators to request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to the Secretary with sufficient justification of the need for the extension in accordance with the technical correction at section 5 of the 2011 Pipeline Safety Act. The committee had no objections or substantial comments on this provision and voted 12-0 that it was, as published, technically feasible, reasonable, cost-effective, and practicable.

Safety Features on ILI Launchers and Receivers (§ 192.750):

In the NPRM, PHMSA proposed to require operators equip ILI tool launchers and receivers with a device capable of safely relieving pressure in the barrel before the insertion or removal of ILI tools, scrapers, or spheres. Further, PHMSA proposed requiring operators to use a suitable device to indicate that pressure has been relieved in the barrel or otherwise provide a means to prevent the opening of the barrel if pressure has not been relieved. The committee voted 12-0 that this provision was, as published, technically feasible, reasonable, cost-effective, and practicable, as long as PHMSA clarified that the rule language does not require “relief valves” or use “relief valve” as a term. Some committee members were concerned that using language related to “relief valves” would bring in other code requirements, which was not PHMSA’s intent.

Seismicity (§§ 192.917, 192.935(b)(2)):

In the NPRM, PHMSA proposed to include seismicity in the list of factors operators must evaluate for the threat of outside force damage when considering preventative and mitigative measures, as well as include the seismicity of an area as a pipeline attribute in an operator's data gathering and integration when performing risk analyses. The committee had no substantial comments or recommendations on this topic, and they voted 12-0 that this provision was, as published, technically feasible, reasonable, cost-effective, and practicable.

Records (§§ 192.5(d), 192.13(e), 192.67, 192.127, 192.205, 192.227(c), 192.285(e), 192.619(f), 192.624(f), Appendix A):

In the NPRM, PHMSA proposed to clarify that the records required by part 192 must be documented in a reliable, traceable, verifiable, and complete manner. PHMSA summarized the recordkeeping requirements of part 192 in a new Appendix A, and required that operators must re-establish pipeline documentation whenever records were not available and make and retain records demonstrating compliance with part 192. Issues related to records were discussed through the final 4 GPAC meetings over the course of 2017 and 2018. The committee found the assorted provisions related to records as being technically feasible, reasonable, cost-effective, and practicable, if certain changes were made. Specifically, the committee recommended the word "reliable" be deleted from the records standard so that it reads "traceable, verifiable, and complete" records wherever the standard is used. Members noted that the NTSB never used the term "reliable," and a PHMSA advisory bulletin reflects the language without referring to "reliable" records. In the class location requirements at § 192.5, the committee recommended PHMSA clarify that documentation be required to substantiate the current class location and not previous historical ones. The committee also recommended that PHMSA modify the requirements for the qualification of welders and persons joining plastic pipe to include an effective date and change the records retention provision to a period of 5 years.

During the June 2017 GPAC meeting, the committee recommended PHMSA amend provisions related to the general duty clause for records and edit the corresponding reference to retention periods in Appendix A. After further discussion, during the meeting on March 2, 2018, the committee recommended PHMSA withdraw the proposed addition of § 192.13. Similarly, in the June 2017 meeting, the committee recommended PHMSA modify the proposed Appendix A to clarify that it does not apply to distribution or gathering pipelines. After considering the issue at the meeting on March 2, 2018, the committee recommended PHMSA withdraw proposed Appendix A from the rulemaking.

Other changes the committee suggested regarding the proposed recordkeeping requirements included revising the record provisions for materials, pipe design, and components to clarify the effective date of those provisions and recommended PHMSA clarify that the recordkeeping provisions for components only applies to components greater than 2 inches in nominal diameter. The recordkeeping provisions proposed under the MAOP determination and MAOP reconfirmation sections were discussed by the GPAC separately and are expanded upon under the discussions for those specific topics below.

Following those discussions over the course of multiple meetings, the committee voted unanimously that the provisions related to recordkeeping requirements in part 192 were technically feasible, reasonable, cost-effective, and practicable, if PHMSA made the changes outlined above.

IM Clarifications (§§ 192.917(e)(2), (e)(3) & (e)(4)):

In the NPRM, PHMSA proposed several changes to provisions related to how operators use data in their IM programs and manage certain types of defects. PHMSA proposed changes regarding an operator’s analysis of cyclic fatigue and clarifying that certain pipe, such as low-frequency electric resistance welded pipe, must have been pressure tested for an operator to assume that any seam flaws are stable. PHMSA also proposed that any failures or changes to operation that could affect seam stability must be evaluated using a fracture mechanics analysis.

Regarding cyclic fatigue, some GPAC members expressed concern that PHMSA proposed to require an annual analysis of cyclic fatigue even if the underpinning conditions affecting cyclic fatigue had not changed. Certain GPAC members wanted to ensure that it would be a change in conditions that would trigger an evaluation and that operators would not necessarily need to do an evaluation within a certain period otherwise. During the meeting, PHMSA suggested it would consider changing cyclic fatigue analysis from annually to periodically based on any changes to cyclic fatigue data and other changes to loading conditions since the previous analysis was completed, not to exceed 7 calendar years. Further, PHMSA would consider whether there was conflict with this section and the MAOP reconfirmation requirements, which was a concern brought up during the public comment period of the meeting. Following the discussion, the committee voted 11-0, that the provisions related to cyclic fatigue were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the paragraph based on the GPAC member discussion and PHMSA’s proposed language at the meeting.

For the provisions related to the stability of manufacturing- and construction-related defects, PHMSA proposed during the GPAC meeting to provide that an operator could consider manufacturing- and construction-related defects as stable only if the covered segment has been subjected to a subpart J pressure test of at least 1.25 times MAOP and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent subpart J pressure test. Pipeline segments that have experienced a reportable incident since its most recent subpart J pressure test due to an original manufacturing-related defect, a construction-related defect, an installation-related defect, or a fabrication-related defect would be required to be prioritized as a high-risk segment for the purposes of a baseline assessment or a reassessment. PHMSA proposed to explicitly lay out these requirements in the regulations rather than cross-reference these requirements to the MAOP reconfirmation provisions. Additionally, PHMSA indicated it would create a stand-alone section to deal with pipeline cracking issues within the IM regulations and would delete a specific reference to "pipe body cracking" in the provisions related to electric resistance welded pipe.

Following the discussion, the committee voted 12-0 that the provisions related to IM clarifications regarding manufacturing and construction defects were technically feasible, reasonable, cost-effective, and practicable if PHMSA made the changes it proposed during the meeting, created a new, stand-alone section for addressing pipeline cracking within the IM regulations, deleted the phrase related to "pipe body cracking," and considered allowing other test procedures for determining whether manufacturing- and construction-related defects were stable.

MAOP Exceedances (§§ 191.23, 191.25):

In the NPRM, PHMSA proposed requiring operators to report each exceedance of the MAOP that exceeds the build-up allowed for the operation of pressure-limiting or control devices per the congressional mandate provided in the 2011 Pipeline Safety Act, which requires operators to report such exceedances on or before the 5th day following the date on which the exceedance occurs.

During the public comment period of the June 7, 2017, meeting, a commenter expressed concern that being required to report an exceedance within 5 days might be problematic where an ongoing investigation might preclude an operator from being able to complete a full safety-related condition report. The GPAC considered this viewpoint but noted that the 5-day reporting requirement was prescribed by statute, and PHMSA does not have discretion when implementing that deadline. The GPAC, echoing another comment from the public, discussed whether the provision would be applicable to gathering lines. PHMSA, in response, noted that the requirement would be limited to gas transmission lines only. Following the discussion, the GPAC voted 11-0 that the provision was technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that this provision does not apply to gathering lines.

Verification of pipeline material properties and attributes (§ 192.607):

In the NPRM, PHMSA proposed a process for operators to re-establish material properties on pipelines where those attributes may be unknown. The process was an opportunistic sampling approach that did not require any mandatory excavations and allowed operators to verify material properties of pipelines as opportunities presented themselves during normal operations and maintenance, such as excavations for the repair of anomalies.

The GPAC had a robust discussion on the proposed material properties verification requirements and wanted to clarify that two separate activities – MAOP reconfirmation and the application of IM principles – drive the need for material properties verification and should be addressed separately. Overall, the GPAC was supportive of PHMSA's opportunistic approach for verifying material properties. During the public comment period, members representing the pipeline industry suggested PHMSA allow a statistical sampling plan developed by operators instead of prescribing a specific number of samples needed. PHMSA clarified that it expected a 1 pipe-per-mile sampling standard in most cases.

At the December 2017 GPAC meeting, some GPAC members expressed concern with the specific attributes PHMSA was proposing operators collect and verify. There was also some discussion regarding how the notification procedure PHMSA proposed might be cumbersome if operators would be required to wait on a response or action from PHMSA every time an operator wanted to submit an alternative plan. The GPAC suggested adding language where, if PHMSA was to object to an operator notification, they would have to object within 90 days. If PHMSA did not object within 90 days, the operator would be free to go forward with the intended action.

Following the discussion, the GPAC voted 12-0 that the provisions related to material properties verification were technically feasible, reasonable, cost-effective, and practicable if the following changes were made:

- Clarify that material properties verification applies to onshore steel transmission lines only, and not distribution or gathering lines.
- Remove the applicability criteria of the section and make the material properties verification provisions a procedure that operators can use for obtaining missing or inadequate records or verifying pipeline attributes if required by the MAOP reconfirmation provisions or other code sections. The committee agreed to address the applicability of the material properties verification requirements under each of the MAOP reconfirmation methods and other sections as appropriate.
- Delete the requirements for creating a material properties verification program plan.

- Drop the list of mandatory attributes operators would be required to verify but require that operators keep any records developed through this material properties verification method.
- Retain the opportunistic approach of obtaining unknown or undocumented material properties when excavations are performed for repairs or other reasons, using a one-per-mile standard proposed by PHMSA, but allow operators to use their own statistical approach and submit a notification to PHMSA with their method. Establish a minimum standard of a 95% confidence level for operator statistical methods submitted to PHMSA.
- Retain flexibility to allow either destructive or non-destructive tests when verification is needed.
- Incorporate language stating that, if an operator does not receive an objection letter from PHMSA within 90 days of notifying PHMSA of an alternative sampling approach, the operator can proceed with their method. PHMSA will notify the operator if additional review time is needed.
- Revise the paragraph to accommodate situations where a single material properties verification test is needed (e.g., additional information is needed for an anomaly evaluation/repair).
- Drop accuracy specifications (retain requirement that test methods must be validated and that calibrated equipment be used).
- Drop mandatory requirements for multiple test locations for large excavations (multiple joints within the same excavation).
- Reduce number of quadrants at which NDE tests must be made from 4 to 2.

- Delete specified program requirements for how to address sampling failures and replace with a requirement for operators to determine how to deal with sample failures through an expanded sample program that is specific to their system and circumstances. Require notification to provide expanded sample program to PHMSA, and require operators establish a minimum standard that sampling programs must be based on a minimum 95% confidence level.
- Clarify the applicability of § 192.607 (d)(3)(i).

Strengthened Assessment Requirements (Appendix F, §§ 192.493, 192.506, 192.921(a)):

In the NPRM, PHMSA proposed to clarify the selection and conduct of ILI tools per updated industry standards that would be incorporated by reference, clarify the consideration of uncertainties in ILI reported results, add additional assessment methods to allow greater flexibility to operators, and allow direct assessment as a method only if the pipeline was not piggable. PHMSA also proposed to explicitly allow guided wave ultrasonic testing (GWUT) in the list of integrity assessment methods by codifying in a new Appendix F the current guidelines operators use for submitting GWUT inspection procedures.

For the updated ILI standards, some GPAC members requested PHMSA delete the "requirements and recommendations" language in § 192.493 and other places where standards are incorporated by reference to avoid the consequence that non-mandatory recommendations in the standards would become regulatory requirements. Following the discussion, the GPAC voted 10-0 that the provisions related to strengthened assessment requirements pertaining to in-line assessment standards were technically feasible, reasonable, cost-effective, and practicable if

PHMSA struck the phrase "the requirements and recommendations of" from the appropriate paragraph in § 192.493.

Regarding the usage of assessment methods, certain committee members recommended PHMSA allow the direct assessment method whenever appropriate (i.e., do not restrict the use of direct assessments to unpiggable pipeline segments or when other methods are impractical) and incorporate better language to clarify when it is appropriate for operators to use direct assessments. Similarly, the GPAC suggested PHMSA clarify the regulatory language so that it was clear operators must select the appropriate assessment method based on the applicable threats. The clarification would avoid the implication that operators need to run certain tools against certain threats when there is no evidence or susceptibility of that threat for that particular pipeline segment.

The GPAC also recommended that PHMSA delete the proposed requirement in the baseline assessment method that required a review of ILI results by knowledgeable individuals, since it is duplicative with other existing requirements elsewhere in the regulations. Further, some GPAC members expressed concern that all tools cannot meet the 90 percent tool tolerance that is specified in the referenced industry standard. PHMSA representatives noted that the rule would not require that every tool perform within a 90 percent specification rate, but that actual tool performance should be verified and applied when ILI data is interpreted. As in other sections of the proposed regulations, the committee also requested PHMSA adopt the same objection procedure that the GPAC discussed and approved under the material properties verification provisions for any notification under this section.

Following the discussion, the GPAC voted 10-0 that the provisions related to strengthening the conduct of a baseline integrity assessment were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the requirements to clarify that operators must select assessment methods based on the threats to which the pipeline is susceptible and removed language in the provision that is duplicative with requirements elsewhere in the regulations; clarified that direct assessment is allowed where appropriate but may not be used to assess threats for which the method is not suitable; and incorporated the same objection procedure the committee approved for the material properties verification provisions and with a PHMSA review timeframe of 90 days.

In discussing the provisions related to the "spike" hydrostatic pressure test method, the committee had several comments and recommendations. Specifically, some GPAC members recommended that the spike test should be performed at a pressure level of 100 percent SMYS, and not 105 percent, to account for varying elevations and test segment lengths. They also suggested that the 30-minute hold time was too long and requested PHMSA consider minimizing the duration of the spike pressure to avoid growing subcritical cracks. Further, the GPAC recommended PHMSA clarify that spike testing should be performed against the threat of "time-dependent cracking" and remove instances in other sections of the regulations where PHMSA listed the threats for which a spike pressure test is appropriate. Following the discussion, the committee voted 10-0 that the provisions related to the "spike" hydrostatic pressure test method were technically feasible, reasonable, cost-effective, and practicable if PHMSA changed the minimum spike pressure to whichever is lesser: 100 percent SMYS or 1.5 times MAOP, reduced the spike hold time to a minimum of 15 minutes after the spike pressure stabilizes, referred to "time-dependent cracking" in the section, incorporated the same objection procedure the committee approved for the material properties verification provisions and with a PHMSA review timeframe of 90 days, and incorporated the term "qualified technical subject matter expert" (SME) at the SME requirements.

The GPAC did not have major concerns with incorporating the GWUT procedures into the regulations and voted 13-0 that the provisions related to the GWUT process were technically feasible, reasonable, cost-effective, and practicable if PHMSA revised the objection procedure as recommended by GPAC members during the discussion on the proposed material properties verification requirements and considering certain minor technical recommendations made by the GPAC members.

Moderate Consequence Area Definition (§ 192.3):

In the NPRM, PHMSA proposed a new definition for "Moderate Consequence Areas" (MCA) which would be areas operators would have to assess per the proposed requirements for performing integrity assessments outside of HCAs. PHMSA proposed to define an MCA as an area in a "potential impact circle"[84] with 5 or more buildings intended for human occupancy; an "occupied site;" or the right-of-way of an interstate, freeway, expressway, and other principal 4-lane arterial roadway. PHMSA proposed the definition of an "occupied site" to be areas or buildings occupied by 5 or more persons, which was the same as an "identified site" under the HCA definitions at § 192.903, except that the occupancy threshold was lowered from 20 persons to 5 persons.

The GPAC, based on a comment made by a member of the public, asked if PHMSA could provide more guidance on what a "piggable" line is, for the purposes of this definition. The

[84] A "potential impact circle" is defined under § 192.903 as "a circle of radius equal to the potential impact radius," where the "potential impact radius" is the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property.

GPAC asked whether PHMSA believed that qualifier applies to pipelines that can be fully assessed by a traditional, free-swimming ILI tool without further modification to the pipeline, and PHMSA noted during the meeting that a "piggable" line would be one without physical or operational modifications. The GPAC then suggested PHMSA clarify that definition in the preamble of this final rule.

GPAC members representing the public were concerned about PHMSA's proposal during the meeting to eliminate the concept of an "occupied site" from the MCA definition. Industry members argued that, from a practicability standpoint, determining whether five people were in a location at any given time could be difficult, and there was significant overlap between "occupied sites" and the class locations that would need to be assessed per the proposal. The GPAC discussed whether some of these sites would be included within an operator's HCA identification program already and, if not, whether operators would be able to otherwise incorporate "occupied sites" into their identification and assessment programs.

Several GPAC members discussed whether PHMSA should create a database or provide other guidance on which highways should be included in the MCA definition for consistency between PHMSA, State regulators, and operators. Those comments regarding highways were made following a public comment asking whether certain elevated highways needed to be included.

Following the discussion, the GPAC voted 10-0 that the MCA definition was technically feasible, reasonable, cost-effective, and practicable if PHMSA changed the highway description to remove the reference to "rights-of-way" and added language so that the highway description includes "any portion of the paved surface, including shoulders;" clarified that highways with 4 or more lanes are included within the definition; discussed in the preamble what the definition of "piggable" is; and worked with the Federal Highway Administration to provide operators with clear information and discuss it in the preamble of this final rule. Additionally, the GPAC recommended PHMSA modify the term "occupied sites" in the definition by removing "5 or more persons" and the occupancy timeframe of 50 days, and tie the requirement into the HCA survey for "identified sites" as discussed by members and PHMSA at the meeting. Such identification could be made through publicly available databases and class location surveys, and PHMSA was to consider the sites and enforceability per direction by the committee members.

Assessments outside of HCAs (§ 192.710):

In the NPRM, PHMSA proposed to require operators perform integrity assessments of certain pipelines outside of HCAs. Specifically, operators would perform an initial assessment within 15 years and periodic assessments 20 years thereafter of pipelines in Class 3 and Class 4 locations as well as piggable pipelines in newly-defined "moderate consequence areas" as discussed above.

The GPAC, based on a public comment during the meeting, questioned whether the timeframes for the initial assessment and periodic assessments were appropriate. Members debated shortening the time frames and suggested a few timeframes that could be based on a risk-based prioritization and taking into account timeframes for HCA assessments.

Following the discussion, the GPAC voted 10-0 that the provisions related to assessments outside of HCAs were technically feasible, reasonable, cost-effective, and practicable if PHMSA clarified that direct assessment can be used as an assessment method only if appropriate for the threat being assessed but cannot be used to assess threats for which direct assessment is not suitable; revised the initial assessment and reassessment intervals from 15 years and 20 years, respectively, to 14 years and 10 years, respectively, and with a risk-based prioritization; revised the applicability requirements to apply to lines with MAOPs of 30 percent SMYS or greater; and removed the provisions related to low-stress assessments.

MAOP reconfirmation (§ 192.624):

In the NPRM, PHMSA proposed a testing regime for 1) pipelines in HCAs, Class 3 or Class 4 locations, or "piggable" MCAs that experienced a reportable in-service incident due to certain types of defects since its most recent successful subpart J pressure test, 2) pipelines in HCAs or Class 3 or Class 4 locations that lacked the traceable, verifiable, and complete pressure test records necessary to substantiate the current MAOP, and 3) pipelines in HCAs, Class 3 or Class 4 locations, or piggable MCAs where the operator established the MAOP using the "grandfather" clause pursuant to § 192.619(c). PHMSA proposed operators of these pipelines re-confirm the MAOP of those pipelines by choosing and executing one of a variety of methods. Those methods are discussed in more detail in individual sections below.

MAOP reconfirmation scope and completion date

During the discussion on MAOP reconfirmation, some GPAC members suggested PHMSA revise the applicability of the provisions to remove pipeline segments with prior crack or seam incidents, as those issues would be dealt with in an operator's IM program. Certain committee members recommended PHMSA restrict the scope of the MAOP reconfirmation provisions to pipeline segments with MAOPs of 30 percent SMYS or greater. These members argued that threshold was explicit in the congressional mandate as it pertained to previously untested pipe, and that it was based on the concept that lower-stress lines leak rather than rupture. Members further suggested that the benefit in addressing low-stress lines was not commensurate with the cost of doing so. Other committee members supported retaining the scope of PHMSA's proposals in the NPRM in order to address specific NTSB recommendations.

Following the discussion, the committee voted 13-0 that the provisions related to the scope for MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA removed pipelines with previous reportable incidents due to crack defects from the applicability paragraph; addressed pipeline segments with crack incident history in a new paragraph under the IM requirements; withdrew the definitions for "modern pipe," "legacy pipe," and "legacy construction techniques;" revised a reference to necessary records within the applicability paragraph to refer to records needed for MAOP determination and not subpart J pressure test records; and revised the applicability of the requirements for grandfathered lines to apply only to those lines with MAOPs of 30 percent or greater of SMYS. The committee also recommended PHMSA review the costs and benefits of making the requirements applicable to Class 3 and Class 4 non-HCA pipe operating below 30 percent SMYS.

As for the completion date for the MAOP reconfirmation requirements, the GPAC voted 13-0 that the related provisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA addressed how the completion plan and completion dates required by the section would apply to pipelines that currently do not meet the applicability conditions but may in the future. The committee suggested PHMSA could add a phrase stating that operators must complete all actions required by the section on 100 percent of the applicable pipeline mileage 15 years after the effective date of the rule or, as soon as practicable but not to exceed 4 years after the pipeline segment first meets the applicability conditions, whichever date is later. The GPAC also recommended that PHMSA consider a waiver or no-objection procedure for extending that timeline past 4 years, if necessary.

MAOP Reconfirmation: Methods 1 and 2 (Pressure Test and Pressure Reduction)

In the NPRM, PHMSA proposed six methods an operator could use if needing to reconfirm MAOP. Method 1, a hydrostatic pressure test, would be conducted at 1.25 times MAOP or the MAOP times the class location test factor, whichever is greater. PHMSA proposed operators use a "spike" test method on pipeline segments with reportable in-service incidents due to known manufacturing or construction issues, and PHMSA also proposed operators estimate the remaining life of pipeline segments with crack defects. Method 2, a pressure reduction, would allow operators to reduce the pipeline segment's MAOP to the highest operating pressure divided by 1.25 times MAOP or the class location test factor times MAOP, whichever is greater. Similar to Method 1, PHMSA proposed operators taking a pressure reduction to reconfirm MAOP be required to estimate the remaining life of pipeline segments with crack defects.

The GPAC members representing the industry argued that a "spike" test is more appropriate to include under IM requirements and that it is not appropriate for MAOP reconfirmation. During the meeting, PHMSA noted that if the scope of the MAOP reconfirmation provisions was to be revised to delete lines with crack-like defects, the spike test requirement would not be needed. However, PHMSA would expect the spike test provisions to be utilized when otherwise required by the regulations. GPAC members also suggested adding language to address material properties verification requirements with respect to the information that is needed to conduct a pressure test. At the meeting, PHMSA suggested that the GPAC consider explicitly requiring that any information an operator does not have to perform a successful pressure test in accordance with subpart J (or that is not documented in traceable, verifiable, and complete records) be verified in accordance with the material properties verification provisions.

Following the discussion, the GPAC voted 12-0 that the provisions related to the pressure test method for MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA deleted the spike hydrostatic testing component for pipelines with suspected crack defects and referred to subpart J more broadly instead of certain sections within subpart J. The GPAC also recommended that if the pressure test segment does not have traceable, verifiable, and complete MAOP records, operators should use the best available information upon which the MAOP is currently based to perform the pressure test. The committee recommended PHMSA require operators of such pipeline segments add those segments to its plan for opportunistically verifying material properties in accordance with the material properties verification requirements, noting that most pressure tests will present at least two opportunities for material properties verification at the test manifolds.

As for the pressure reduction method of MAOP reconfirmation, the GPAC voted 12-0 that the related provisions were technically feasible, reasonable, cost-effective, and practicable if PHMSA increased the look-back period from 18 months to 5 years and removed the requirement for operators to perform fracture mechanics analysis on those pipeline segments where the pressure is being reduced to reconfirm the MAOP.

MAOP Reconfirmation: Method 3 (Engineering Critical Assessment and Fracture Mechanics)

In the NPRM, PHMSA proposed allowing operators to use an engineering critical assessment (ECA) analysis in conjunction with an ILI assessment to reconfirm a pipeline segment's MAOP where the segment's MAOP would be based upon the lowest predicted failure pressure (PFP) of the segment. This method would require specific technical documentation and material properties verification, and it would require operators analyze crack, metal loss, and interacting defects remaining in the pipe, or that could remain in the pipe, to determine the PFP. The pipeline segment's MAOP would then be established at the lowest PFP divided by 1.25 or by the applicable class location factor listed under the MAOP determination provisions, whichever of those derating factors is greater.

Most of the GPAC discussion on this portion of MAOP reconfirmation related to the specific values used in the fracture mechanics analysis portion of the ECA and whether those requirements would best be located in a section independent from the MAOP reconfirmation requirements. During the meetings, PHMSA noted it would consider creating a stand-alone fracture mechanics section that could be referenced when the procedure is needed or required by other sections of the regulations. PHMSA clarified that fracture mechanics would be needed in the context of MAOP reconfirmation only for the ECA method and "other technology" usage under Method 6 where the applicable pipeline segments have cracks or crack-like defects.

Following the discussion, the GPAC voted 12-0 that the provisions related to the ECA method of MAOP reconfirmation and fracture mechanics were technically feasible, reasonable, cost-effective, and practicable if PHMSA moved the fracture mechanics requirements to a stand-alone section in the regulations. The GPAC recommended the section not specify when, or for which pipeline segments, fracture mechanics analysis would be required, but instead provide a procedure by which operators needing to perform fracture mechanics analysis could do so.

The GPAC recommended several changes to the fracture mechanics requirements, including striking cross-references to the MAOP reconfirmation requirements and spike hydrostatic testing requirements, as well as striking the sensitivity analysis requirements and replacing them with a requirement that operators account for model inaccuracies and tolerances. Additionally, the GPAC recommended PHMSA add a paragraph specifying that any records created through the performance of a fracture mechanics analysis must be retained.

There were several technical GPAC recommendations related to the use of Charpy V-notch toughness values in the fracture mechanics analysis. Specifically, the GPAC recommended operators have the ability to use a conservative Charpy V-notch toughness value based on the sampling requirements of the material properties verification provisions, and that operators could use Charpy V-notch toughness values from similar or the same vintage pipe until the properties are obtained through an opportunistic testing program. Further, the GPAC recommended that the default Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) of 13-ft.-lbs. (body) and 4-ft.-lbs. (seam) only apply to pipe with suspected low-toughness properties or unknown toughness properties. Additionally, the GPAC recommended PHMSA include a requirement for operators of pipeline segments with a history of leaks or failures due to cracks to work diligently to obtain toughness data if unknown and use Charpy V-notch toughness values (full-size specimen, based on the lowest operational temperature) of 5-ft.-lbs. (body) and 1-ft.-lbs. (seam) in the interim. Further, the GPAC suggested PHMSA allow operators to request the use of different default Charpy V-notch toughness values via a 90-day notification to PHMSA.

For the ECA method itself, the committee recommended PHMSA add a requirement to verify material properties in accordance with the material properties verification requirements if the information needed to conduct an ECA is not documented in traceable, verifiable, and complete records. Further, the GPAC recommended that PHMSA not include default Charpy V-notch toughness values or other technical fracture mechanics requirements in the ECA method, as those items would be specified in the new stand-alone fracture mechanics section. Similarly, the GPAC recommended removing ILI tool performance specifications and replacing them with a requirement to verify tool performance using unity plots or equivalent technologies.

MAOP Reconfirmation: Methods 4, 5, and 6 (Pipe Replacement, Small-Diameter & Potential Impact Radius Pressure Reduction, and Other Technology)

In the NPRM, PHMSA proposed three additional methods operators could use to reconfirm a pipeline's MAOP. Method 4, pipe replacement, would require operators to replace pipe for which they have inadequate records or pipe that was not previously tested due to the grandfather clause in § 192.619(c). Method 5, as proposed, was applicable to low-stress, small diameter, and small potential impact radius (PIR) lines,[85] and would require operators to take a 10 percent pressure cut as well as perform more frequent patrols and leak surveys. Method 6, "other technology," would allow operators to use an alternative method, with notification to PHMSA, to reconfirm the MAOP of their applicable pipeline segments.

The GPAC had no major comments regarding Method 4, pipe replacement. For Method 5, GPAC members representing the industry questioned the need for the compensatory safety measures, such as the additional patrols and leak surveys, in conjunction with the 10 percent pressure reduction. They also supported public comments that promoted expanding the applicability of Method 5 beyond the prescribed pipe diameter of less than or equal to 8 inches and the operating pressure of below 30 percent SMYS. During the meeting, PHMSA noted it could drop the diameter and operating pressure requirements from the applicability and use the

[85] These lines would be lines operating below 30 percent SMYS with diameters of 8 inches or less and PIRs of 150 feet or less.

prescribed PIR of 150 feet or less as a proxy for those risk factors. Additionally, PHMSA noted it would expand the look-back period to 5 years to be consistent with committee and public comments regarding the pressure reduction method (Method 2) of MAOP reconfirmation discussed earlier. With regard to the "other technology" method, committee members suggested using the notification procedure developed for the material properties verification requirements, and PHMSA acknowledged it could be included here as well.

Following the discussion, the committee voted 11-0 that the provisions related to the pipe replacement, pressure reduction for small PIR and diameter lines, and "other technology" methods of MAOP reconfirmation were technically feasible, reasonable, cost-effective, and practicable if PHMSA made certain changes. For Method 4, pipe replacement, the committee had no significant comments or changes. For Method 5, the small PIR and diameter pressure reduction method, the GPAC recommended PHMSA delete the size and pressure criteria, limiting the requirement to those lines with a PIR of 150 feet or less; remove the external corrosion direct assessment, crack analysis program, odorization, and fracture mechanics analysis requirements; and change the frequency of patrols and surveys to 4 times per year in Class 1 and Class 2 locations and 6 times per year in Class 3 and Class 4 locations. For Method 6, the "other technology" method, the GPAC recommended PHMSA incorporate the same 90-day notification and objection procedure the GPAC approved for the material properties verification requirements.

MAOP Reconfirmation: Recordkeeping and Notification

The GPAC also voted on the notification procedure and recordkeeping requirements of the MAOP reconfirmation requirements. As there were no substantial GPAC comments on these issues, the GPAC voted 11-0 that the provisions are technically feasible, reasonable, cost-effective, and practicable if PHMSA provided guidance regarding what "traceable, verifiable, and complete" records are in the preamble, and if the notification procedure is retained as it was proposed in the NPRM, but incorporating the same 90-day notification and objection procedure the committee approved for the material properties verification requirements into any notification required under the MAOP reconfirmation requirements.

Other MAOP Amendments (§§ 192.503, 192.605(b)(5), 192.619(a)(2), 192.619(a)(4), 192.619(e), 192.619(f)):

PHMSA presented to the committee issues related to other portions of MAOP determination[86] that had cross-references to MAOP reconfirmation methods or other areas of the proposed regulations. More specifically, the GPAC was to consider recommending PHMSA eliminate duplications in scope between the MAOP determination provisions and the MAOP reconfirmation provisions, and eliminate a duplicative revision to the subpart J pressure test general requirements that was referenced adequately elsewhere in the proposal. PHMSA also proposed that the establishment of MAOP under § 192.619 should rely on traceable, verifiable, and complete records, and therefore cross-referenced the material properties verification provisions with the MAOP determination provisions. Similarly, PHMSA added a paragraph to the existing MAOP determination provisions to more clearly specify that operators must have records to substantiate the MAOP of their pipeline segments. To address an NTSB recommendation from the PG&E incident, PHMSA also proposed requiring that the MAOP pressure limitation factor specified in the MAOP determination section of the regulations for

[86] See § 192.619.

Class 1 pipeline segments be based on the subpart J test pressure divided by 1.25, whereas the existing requirement was the test pressure divided by 1.1. Finally, PHMSA proposed adding a clarification that the requirement for overpressure protection applied to pipeline segments where the MAOP was established using one of the six methods under MAOP reconfirmation. However, PHMSA noted in response to public comment that the clarification seemed to be overly confusing and should be withdrawn.

The GPAC reviewed and discussed PHMSA's proposed changes to the other MAOP-related provisions, voting 12-0 that the provisions are technically feasible, reasonable, cost-effective, and practicable if PHMSA considered editorially restructuring the applicability of the MAOP determination provisions; clarifying that the recordkeeping requirements specified under MAOP determination only apply to onshore, steel, gas transmission pipelines; and clarifying that the MAOP recordkeeping requirements are not retroactive. The GPAC suggested this be clarified by stating existing records for pipelines installed on or before the effective date of the rule must be kept for the life of the pipeline, that pipelines installed after the effective date of the rule must make and retain records as required for the life of the pipeline, and that MAOP records are required for any pipeline placed in service after the effective date of the rule. The GPAC noted that other sections, including the MAOP reconfirmation and material properties verification requirements, would require when and for which pipeline segments where MAOP records are not documented in a traceable, verifiable, and complete manner would need to be verified.

Changes from the GPAC Recommendations

In this final rule, PHMSA considered the recommendations of the GPAC and adopted them as PHMSA deemed appropriate. However, there were recommendations from the GPAC that PHMSA considered but did not adopt. To summarize, the major changes PHMSA made in this rule that deviate from the GPAC recommendations are as follows:

1) When discussing the other proposed issues related to the MAOP requirements, the GPAC recommended PHMSA consider moving § 192.619(e) to be a subsection of § 192.619(a) and consider referencing section § 192.624 in § 192.619(a). PHMSA did not implement this recommendation because MAOP reconfirmation for grandfathered segments is not applicable for new pipeline segments.

2) When considering the IM clarifications at § 192.917, the GPAC recommended PHMSA consider removing the term "hydrostatic" from the testing requirements at § 192.917(e)(3), which deals with manufacturing and construction defects, and allow other authorized testing procedures. PHMSA is not implementing this recommendation because allowing pneumatic tests would be a safety concern to the public and operating personnel.

3) When discussing the assessment requirements for non-HCAs under proposed § 192.710, the GPAC recommended PHMSA change the "discovery of condition" period allotted from 180 to 240 days. PHMSA is not implementing this suggestion from the GPAC and is retaining the 180-day timeframe for operators to determine whether a condition presents a potential threat to the integrity of the pipeline.

4) PHMSA added a notification requirement for the use of other technology under the non-HCA assessment requirements at § 192.710. While the GPAC did not specifically request PHMSA make this change, the GPAC was generally supportive of incorporating the notification procedure the committee agreed to under the proposed material properties verification requirements for other applications.

5) Regarding the requirements for the scope of MAOP reconfirmation, the GPAC recommended PHMSA review the costs and benefits of including Class 3 and Class 4 pipelines not located in HCAs and that operate at less than 30 percent SMYS. PHMSA did consider this as an alternative in the RIA but chose not to move forward with the proposal as suggested as it is outside the scope of the mandate.

6) Regarding the MCA definition, the GPAC recommended PHMSA consider modifying the term "occupied sites" within the definition by removing reference to "5 or more persons" and the timeframe of 50 days and tying the requirement for identifying occupied sites to the HCA "identified sites" survey requirement as discussed by members and PHMSA at the meeting. In this final rule, PHMSA chose to delete the term "occupied sites" from the MCA definition and from the general definitions section of part 192.

7) PHMSA moved the specific ECA requirements outside of the MAOP reconfirmation section into a new stand-alone § 192.632. The MAOP reconfirmation requirements regarding the ECA method at § 192.624(c)(3) and the ECA requirements in § 192.632 will cross-reference each other. PHMSA made this change to streamline the MAOP reconfirmation provisions and improve the readability of the requirements. No substantive changes were made to the procedure in connection with this reorganization; this was a stylistic change only.

V. Section-by-Section Analysis

§ 191.23 Reporting safety-related conditions.

Section 23 of the 2011 Pipeline Safety Act requires operators to report each exceedance of 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 2011 Pipeline Safety Act to report such exceedances. PHMSA is revising § 191.23 to codify this statutory requirement.

§ 191.25 Filing safety-related condition reports.

Section 23 of the 2011 Pipeline Safety Act requires operators to report each exceedance of the MAOP that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices. As described above, PHMSA is revising § 191.23 to codify this requirement. Section 191.25 is also revised to make conforming edits and comply with the mandatory 5-day reporting deadline specified in section 23 of the 2011 Pipeline Safety Act.

§ 192.3 Definitions.

Section 192.3 provides definitions for various terms used throughout part 192. In support of other regulations adopted in this final rule, PHMSA is amending the proposed definition of "*Moderate consequence area*." This change will define this term as it is used throughout part 192.

The definition of a *"moderate consequence area,"* or MCA, is based on similar methodology used to define *"high consequence area,"* or HCA in § 192.903. Moderate consequence areas will define the subset of non-HCA locations where integrity assessments are required (§ 192.710) and where MAOP reconfirmation is required (§ 192.624). The criteria for determining MCA locations differs from the criteria currently used to identify HCAs in that the threshold for buildings intended for human occupancy located within the potential impact radius is lowered from 20 to 5, and identified sites are excluded. In response to NTSB recommendation

P-14-01, which was issued as a result of the incident near Sissonville, WV, the MCA definition also includes locations where interstate highways, freeways, expressways, and other principal 4-or-more-lane arterial roadways are located within the potential impact radius.

PHMSA is also adopting a definition of an "*engineering critical assessment*," as that term will be used in §§ 192.624 and 192.632. More specifically, the ECA is a documented analytical procedure that operators can use to determine the maximum tolerable size for pipeline imperfections based on the MAOP of the particular pipeline segment. Operators can use an ECA in conjunction with an ILI inspection as one of the methods to reconfirm MAOP, if required.

§ 192.5 Class locations.

Section 23 of the 2011 Pipeline Safety 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. This final rule adds a new paragraph, § 192.5(d), to require each operator of transmission pipelines to maintain records documenting the current class location of each pipeline segment and demonstrating how an operator determined each current class location 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 is making conforming amendments to § 192.7 in the rule text to reflect other changes adopted in this final rule.

§ 192.9 What requirements apply to gathering lines?

This final rule codifies new standards for gas transmission pipelines, most of which are not intended to be applied to gas gathering pipelines. PHMSA is making conforming amendments to § 192.9 to clarify which provisions apply only to gas transmission pipelines and not to gas gathering pipelines.

§ 192.18 How to notify PHMSA.

This final rule allows operators to notify PHMSA of proposed alternative approaches to achieving the objective of the minimum safety standards in several different regulatory sections. These notification procedures for alternative actions are comparable to the existing notification requirements in subpart O for the integrity management regulations. Because PHMSA is expanding the use of notifications to pipeline segments for which subpart O does not apply (i.e., to non-HCA pipeline segments), PHMSA is adding a new § 192.18 in subpart A that contains the procedure for submitting such notifications for any pipeline segment.

§ 192.67 Records: Material properties.

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records 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 properties records are complete and accurate. This final rule moves the original § 192.67 to § 192.69 and adds in its place a new § 192.67 that requires each operator of gas transmission pipelines installed after the effective date of this final rule to collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured. The physical characteristics an operator must keep documented include diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition. These requirements also apply to any new materials or components that are put on existing pipelines. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. These recordkeeping requirements apply to offshore gathering lines and Type A gathering lines in accordance with § 192.9.

Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.69 Storage and handling of plastic pipe and associated components.

Previous § 192.67, titled "Storage and handling of plastic pipe and associated components," was created as a part of the Plastic Pipe rule, which was published on November 20, 2018 (83 FR 58716). PHMSA is redesignating that section in this final rule to a new § 192.69. No other changes have been made to the section.

§ 192.127 Records: Pipe design.

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records 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. For pipelines installed after the effective date of this final rule, this final rule adds a new § 192.127 to require each operator of gas transmission pipelines to collect or 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. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.150 Passage of internal inspection devices.

The current pipeline safety regulations in § 192.150 require that pipelines be designed and constructed to accommodate in-line inspection devices. Prior to this rulemaking, part 192 was silent on technical standards or guidelines for implementing requirements to assure pipelines are designed and constructed for in-line inspection assessments. Previously, there was no consensus industry standard that addressed design and construction requirements for in-line inspection assessments. NACE Standard Practice, NACE SP0102-2010, "In-line Inspection of Pipelines," has since been published and provides guidance on this issue in section 7. The incorporation of this standard into the Federal Pipeline Safety Regulations at § 192.150 will promote a higher level of safety by establishing consistent standards for the design and construction of pipelines to accommodate in-line inspection devices.

§ 192.205 Records: Pipeline components.

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records 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. For pipelines installed after the effective date of this final rule, this final rule adds a new § 192.205 to require each operator of gas transmission pipelines to collect or make, and retain for the operational life of the component, records documenting manufacturing and testing information for valves and other pipeline components. For pipelines installed prior to the effective date of this final rule, operators are required to retain for the life of the pipeline all such records in their possession as of the effective date of this final rule. Pipelines that lack the traceable, verifiable, and complete records needed to substantiate MAOP may be subject to the MAOP reconfirmation requirements at § 192.624, as specified in that section.

§ 192.227 Qualification of welders.

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records 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 qualification records are complete and accurate. This final rule adds a new paragraph, § 192.227(c), to require each operator of gas transmission pipelines to make and retain records demonstrating each individual welder's qualification in accordance with this section for a minimum of 5 years following construction. This requirement will apply to pipelines installed after one year from the effective date of the rule.

§ 192.285 Plastic pipe: Qualifying persons to make joints.

Section 23 of the 2011 Pipeline Safety Act requires the Secretary of Transportation to require the verification of records 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 plastic pipeline qualification records are complete and accurate. This final rule adds a new paragraph, § 192.285(e), to require each operator of gas transmission pipelines to make and retain records demonstrating a person's plastic pipe joining qualifications in accordance with this section for a minimum of 5 years following construction. This requirement will apply to pipelines installed after one year from the effective date of the rule.

§ 192.493 In-line inspection of pipelines.

The current pipeline safety regulations at §§ 192.921 and 192.937 require that operators assess the material condition of pipelines in certain circumstances (e.g., IM assessments for pipelines in HCAs) and allow the use of ILI 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. Presently, part 192 is silent on the technical standards or guidelines for performing ILI assessments or implementing these requirements. When the IM regulations were initially promulgated, there were no uniform industry standards for ILI assessments. Three related standards have since been published:

- API STD 1163-2013, "In-Line Inspection Systems Qualification Standard." This Standard serves as an umbrella document to be used with and as a complement to 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-2005 (2010), "In-line Inspection Personnel Qualification and Certification."

API 1163-2013 is more comprehensive and rigorous than the current requirements in 49 CFR part 192. The incorporation of this standard into the Federal 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 ILI 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.
- ILI system selection.
- Qualification of performance specifications.
- System operational validation.
- System results qualification.
- Reporting requirements.

- Quality management system.

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 determined 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 product. 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 tethered or remotely controlled ILI tools. PHMSA determined that many of the provisions in the NACE standard can be applied to tethered or remotely controlled ILI tools. Therefore, PHMSA is amending the Federal Pipeline Safety Regulations to allow the use of these tools, provided they 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 the regulations will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes and software utilized by the ILI 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 final rule adds a new § 192.493 to require compliance with the three consensus standards discussed above when conducting ILI of pipelines.

§ 192.506 Transmission lines: Spike hydrostatic pressure test.

A pressure test that incorporates a short duration "spike" pressure is a proven means to confirm the strength of pipe with known or suspected threats of cracks or crack-like defects (e.g., stress corrosion cracking, longitudinal seam defects, etc.). Currently, part 192 does not include minimum standards for such a spike hydrostatic pressure test. This final rule adds a new § 192.506 to codify the minimum standards for performing spike hydrostatic pressure tests when operators are required to, or elect to, use this assessment method. Under the spike hydrostatic pressure test requirements, an operator may use other technologies or processes equivalent to a spike hydrostatic pressure test with justification and notification in accordance with § 192.18.

§ 192.517 Records: Tests.

Section 192.517 prescribes the recordkeeping requirements for each test performed under §§ 192.505 and 192.507. PHMSA is making conforming amendments to § 192.517 to add the recordkeeping requirements for the new § 192.506.

§ 192.607 Verification of pipeline material properties and attributes: Onshore steel transmission pipelines.

Section 23 of the 2011 Pipeline Safety Act mandates the Secretary of Transportation to require operators of gas transmission pipelines in Class 3 and Class 4 locations and Class 1 and Class 2 locations in HCAs to verify records to ensure the records accurately reflect the physical and operational characteristics of the pipelines and confirm the MAOP of the pipelines established by the operator (49 U.S.C. 60139). 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 Annual Reports (starting for calendar year 2012) indicating that a portion of transmission pipeline segments do not have adequate records to establish MAOP and that some operators do not have traceable, verifiable, and complete records that accurately reflect the physical and operational characteristics of the pipeline. Therefore, PHMSA has determined that additional regulations are needed to implement the 2011 Pipeline Safety Act. This final rule promulgates specific criteria for determining which pipeline segments must undergo examinations and tests to understand and document physical and material properties and reconfirm a proper MAOP. For operators that do not have traceable, verifiable, and complete documentation for the physical pipeline characteristics and attributes of a pipeline segment, PHMSA is adding a new § 192.607 that contains the procedure for verifying and documenting pipeline physical properties and attributes that are not documented in traceable, verifiable, and complete records and to establish standards for performing these actions. For operators of certain pipelines lacking the necessary records to substantiate MAOP, PHMSA is also adding § 192.624, which provides operators several methods for reconfirming a pipeline segment's MAOP.

The new material properties verification requirements at § 192.607 include the scope of information needed and the methodology for verifying material properties and attributes of pipelines. The most difficult information to obtain, from a technical perspective, is the strength of the pipeline's steel. Conventional techniques to obtain that data would include cutting out a piece of pipe and destructively testing it to determine the yield and ultimate tensile strength. In this final rule, PHMSA is providing operators with flexibility by allowing the use of non-destructive techniques that have been validated to produce accurate results for the grade and type of pipe being evaluated (see § 192.624).

Another issue regarding material properties verification is the cost associated with excavating the pipeline to verify material properties and determining how much pipeline needs to be exposed and tested to have assurance of the accuracy of the verification. PHMSA addresses these issues within this final rule by specifying that operators can take advantage of opportunities when the pipeline is already being exposed, such as when maintenance activity is occurring and when anomaly repairs are being made, to verify material properties that are not documented in traceable, verifiable, and complete records. For example, PHMSA considers excavations associated with the direct examination of anomalies, pipeline relocations at road crossings and river or stream crossings, pipe upgrades for class location changes, pipe cut-outs for hydrostatic pressure tests, and excavations where pipe is replaced due to anomalies to be opportunities to perform material properties verification. Over time, pipeline operators will develop a substantial set of traceable, verifiable, and complete material properties data, which will provide assurance that material properties are reliably known for the population of segments that did not have pipeline physical properties and attributes documented in traceable, verifiable, and complete records previously. Through this final rule, PHMSA is requiring that operators continue this opportunistic material properties verification process until the operator has completed enough verifications to obtain a high level of confidence that only a small percentage of pipeline segments have physical pipeline characteristics and attributes that are not verified or are otherwise inconsistent with all available information or operators' past assumptions. This final rule specifies the number of excavations required for operators to achieve this level of confidence.

Operators may use an alternative sampling approach that differs from the sampling approach specified in the requirements if they notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.

Requirements are also included in the material properties verification section to ensure that operators document the results of the material properties verification process in records that must be retained for the life of the pipeline.

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

The NTSB report on the PG&E incident 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 final rule revises the test pressure factors in § 192.619(a)(2)(ii) to correspond to at least 1.25 times MAOP for pipelines installed after the effective date of this rule.

The NTSB also recommended repealing § 192.619(c), commonly referred to as the "grandfather clause," 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). Similarly, section 23 of the 2011 Pipeline Safety Act requires that selected pipeline segments in certain locations with previously untested pipe (i.e., the MAOP is established under § 192.619(c)) or without MAOP records be tested with a pressure test or equivalent means to reconfirm the pipeline's MAOP. These requirements are addressed in the new § 192.624 and are described in more detail in the following section. This final rule also makes conforming changes to § 192.619 to require that operators of pipeline segments to which § 192.624 applies establish and document the segment's MAOP in accordance with § 192.624.

§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

Section 23 of the 2011 Pipeline Safety Act requires the verification of records for pipe in Class 3 and Class 4 locations, and high-consequence areas in Class 1 and Class 2 locations, to ensure they accurately reflect the physical and operational characteristics of the pipelines and confirm the established MAOP of the pipelines. Operators have submitted information in annual reports (beginning in calendar year 2012) indicating that some gas transmission pipeline segments do not have adequate material properties records or testing records to confirm physical and operational characteristics and to establish MAOP. For these pipelines, the 2011 Pipeline Safety Act requires that PHMSA promulgate regulations to require operators to reconfirm MAOP as expeditiously as economically feasible. The statute also requires PHMSA to issue regulations that require previously untested pipeline segments located in HCAs and operating at greater than 30 percent SMYS be tested to confirm the material strength of the pipelines. 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 PG&E incident, the NTSB issued two related recommendations. NTSB recommended that PHMSA repeal § 192.619(c), commonly referred to as the "grandfather clause," 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). The 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 pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the MAOP (P-11-15).

Through this final rule, PHMSA is finalizing a new § 192.624 to address these mandates and recommendations. This final rule requires that operators reconfirm and document MAOP for certain onshore steel gas transmission pipelines located in HCAs or MCAs that meet one or more of the criteria specified in § 192.624(a). More specifically, this section applies to (1) pipelines in HCAs or Class 3 or Class 4 locations lacking traceable, verifiable, and complete records necessary to establish the MAOP (per § 192.619(a)) for the pipeline segment, including, but not limited to, hydrostatic pressure test records required by § 192.517(a); and (2) pipelines where the MAOP was established in accordance with § 192.619(c)**,** the pipeline segment's MAOP is greater than or equal to 30 percent of SMYS, and the pipeline is located in an HCA, a Class 3 or Class 4 location, or an MCA that can accommodate inspection by means of instrumented inline inspection tools (i.e., "smart pigs"). This approach implements the mandate in the 2011 Pipeline Safety Act for pipeline segments in HCAs and Class 3 and Class 4 locations (49 U.S.C. 60139). In addition, the scope includes pipeline segments in the newly defined MCAs. 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. Though PHMSA is subjecting certain grandfathered pipeline segments to the MAOP reconfirmation requirements of § 192.624, PHMSA is not repealing § 192.619(c) for pipeline segments located outside of HCAs, Class 3 or Class 4 locations, or MCAs that can accommodate inspection by means of instrumented ILI tools. Previously grandfathered pipelines that reconfirm MAOP using one of the methods of § 192.624 that operate above 72 percent SMYS may continue to operate at the reconfirmed pressure.

The methods to reconfirm MAOP are specified in § 192.624 and are as follows:

Method 1 – Pressure test. The pressure test method as specified in section 23 of the 2011 Pipeline Safety Act. Operators choosing to pressure test must also verify material property records in accordance with § 192.607. PHMSA notes that a pressure test requires the cutout of pipe at test manifold sites and those pipe cutouts would be a prime example of pipe that could and should be tested through the material properties verification procedure, if necessary. In accordance with the statute, PHMSA determined that the following methods (2) through (6) are equally effective as a pressure test for the purposes of reconfirming MAOP.

Method 2 – Pressure reduction. De-rating the pipeline segment so that the new MAOP is less than the historical actual sustained operating pressure by using a pressure test safety factor of 0.80 (for Class 1 and Class 2 locations) or 0.67 (for Class 3 and Class 4 locations) 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 Class 1 and Class 2 locations and 1.5 times MAOP for Class 3 and Class 4 locations).

Method 3 – Engineering critical assessment. An in-line inspection, previously performed pressure test, or alternative technology and engineering critical assessment process using technical analysis with acceptance criteria to establish a safety margin equivalent to that provided by a new pressure test. PHMSA organized the ECA process requirements under a new § 192.632 and established the technical requirements for analyzing the predicted failure pressure as a part of the ECA analysis in a new § 192.712. If an operator chooses the ECA method for MAOP reconfirmation but does not have any of the material properties necessary to perform an ECA analysis (diameter, wall thickness, seam type, grade, and Charpy V-notch toughness values, if applicable), the operator must include the pipeline segment in its program to verify the undocumented information in accordance with the material properties verification requirements at § 192.607.

Method 4 – Pipe replacement. Replacement of the pipe, which would require a new pressure test that conforms with subpart J before the pipe is placed into service.

Method 5 – Pressure reduction for pipeline segments with small potential impact radii. For pipeline segments with a potential impact radius of less than or equal to 150 feet, a pressure reduction using a safety factor of 0.90 times the sustained operating pressure is allowed (equivalent to a pressure test of 1.11 times MAOP), supplemented with additional preventive and mitigative measures specified in this final rule.

Method 6 – Alternative technology. Other technology that the operator demonstrates provides an equivalent or greater level of safety, provided PHMSA is notified in advance in accordance with § 192.18.

Lastly, this final rule includes a new paragraph, § 192.624(f), to clearly specify that records created while reconfirming MAOP must be retained for the life of the pipeline.

§ 192.632 Engineering critical assessment for maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

The requirements for reconfirming MAOP in the new § 192.624 include an option for operators to perform an engineering critical assessment, or ECA, to reconfirm MAOP in lieu of pressure testing and the other methods provided. The requirements for conducting such an ECA were proposed under the MAOP reconfirmation requirements at § 192.624(c)(3); however, PHMSA has moved the ECA requirements to a new, stand-alone section and cross-referenced those requirements in order to improve the readability of the MAOP reconfirmation requirements.

Operators choosing the ECA method for MAOP reconfirmation may perform an in-line inspection and a technical analysis with acceptance criteria to establish a safety margin equivalent to that provided by a pressure test. PHMSA established the technical requirements for analyzing the predicted failure pressure as a part of the ECA analysis in a new § 192.712, and those requirements are cross-referenced within this ECA process.

Although PHMSA expects that most operators will use an ECA in conjunction with in-line inspection, PHMSA would also allow operators with past, valid pressure tests to calculate the largest defects that could have survived the pressure test and analyze the postulated defects to calculate a predicted failure pressure with which to establish MAOP. This approach might be desirable for operators in certain circumstances, such as for line segments that have valid pressure test records, but that lack other records (such as material strength or pipe wall thickness) necessary to determine design pressure and establish MAOP under the existing § 192.619(a). Another situation for which operators could use this approach would be if the operator has a valid pressure test, but it was not conducted at a test pressure that was high enough to establish the current MAOP.

Operators with pressure test records meeting the subpart J test requirements may use an ECA by calculating the largest defect that could have survived the pressure test and estimating the flaw growth between the date of the test and the date of the ECA. The ECA is then performed using these postulated defect sizes. In addition, operators must calculate the remaining life of the most severe defects that could have survived the pressure test and establish an appropriate re-assessment interval in accordance with new § 192.712.

If an operator chooses to use ILI to characterize the defects remaining in the pipe segment and the ECA method for MAOP reconfirmation but does not have one or more of the material properties necessary to perform an ECA analysis (diameter, wall thickness, seam type, grade, and Charpy v-notch toughness values, if applicable), the operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with the material properties verification requirements at § 192.607.

§ 192.710 Transmission lines: Assessments outside of high consequence areas.

Section 5 of the 2011 Pipeline Safety Act requires, if appropriate, the Secretary of Transportation to issue regulations expanding IM system requirements, or elements thereof, beyond HCAs. 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 are therefore not subject to subpart O. However, only approximately 7 percent of onshore gas transmission pipelines are located in HCAs. Through this final rule, operators are required to periodically assess Class 3 locations, Class 4 locations, and MCAs that can accommodate inspection by means of an instrumented inline inspection tool. The periodic assessment requirements under this section apply to pipelines in these locations with MAOPs greater than or equal to 30 percent of SMYS.

Industry has, as a practical matter, assessed portions of pipelines in non-HCA segments coincident with integrity assessments of HCA pipeline segments. For example, INGAA has noted in comment submissions that approximately 90 percent of Class 3 and Class 4 mileage not in HCAs are presently assessed during IM assessments. This is because, in large part, ILI or pressure testing, by their nature, assess large continuous pipeline segments that may contain some HCA segments but that could also contain significant amounts of non-HCA segments.

While INGAA does not represent all pipeline operators subject to part 192, it does represent the majority of gas transmission operators. PHMSA has determined that, given this level of assessment, it is appropriate and consistent with industry direction to codify requirements for operators to periodically assess certain gas transmission pipelines outside of HCAs to monitor for, detect, and remediate pipeline defects and anomalies. Additionally, 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 is basing the requirements for identifying those locations on processes already being implemented by pipeline operators. More specifically, the MCA definition assumes a similar process used for identifying HCAs, with the exception that the threshold for buildings intended for human occupancy located within the potential impact circle is reduced from 20 to 5.

Because significant non-HCA pipeline mileage has been previously assessed in conjunction with the regular assessment of HCA pipeline segments, PHMSA is allowing operators to count those prior assessments as compliant with the new § 192.710 for the purposes of assessing non-HCAs if those assessments were conducted, and threats remediated, in conjunction with an integrity assessment required by subpart O.

This final rule also requires that the assessment required by the new § 192.710 be conducted using the same methods as adopted for HCAs (see § 192.921, below). Operators may use "other technology" as an assessment method, provided the operator notifies PHMSA in accordance with § 192.18.

§ 192.712 Analysis of predicted failure pressure.

The new requirements for reconfirming MAOP in the new § 192.624 include an option for operators to perform an engineering critical assessment, or ECA, to reconfirm MAOP in lieu of pressure testing and the other methods provided. A key aspect of the ECA analysis is the detailed analysis of the remaining strength of pipe with known or assumed defects. The current Federal Pipeline Safety Regulations in subparts I and O refer to methods for predicting the failure pressure for pipe with corrosion metal loss defects. However, the regulations are silent on performing such analysis for pipe with cracks (including crack-like defects such as selective seam weld corrosion). Therefore, in this final rule, PHMSA is inserting a new section to address the techniques and procedures for analyzing the predicted failure pressures for pipe with corrosion metal loss and cracks or crack-like defects. Examples of technically proven models for calculating predicted failure pressures include: for the brittle failure mode, the Newman-Raju Model[87] and PipeAssess PI™ software;[88] and for the ductile failure mode, Modified Log-Secant Model,[89] API RP 579-1[90] – Level II or Level III, CorLas™ software,[91] PAFFC Model,[92] and PipeAssess PI™ software. All failure models used for the ECA analysis must be used within its technical parameters for the defect type and the pipe or weld material properties. Conforming changes are being made to applicable sections in subparts I and O to refer to this new section, for consistency, but the basic techniques are unchanged.

As a part of this section, PHMSA is including a new paragraph to address cracks and crack-like defects, which as stated above is a critical function of the ECA analysis. The ECA analysis 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; the failure mode (ductile, brittle, or both) for the microstructure; the defect's location and type; the pipeline's operating conditions (including pressure cycling); and failure stress and crack

[87] Newman, J.C., and Raju; "Stress Intensity Factors for Cracks in Three Dimensional Finite Bodies Subjected to Tension and Bending Loads;" *Computational Methods in the Mechanics of Fracture*; Elsevier; 1986; pp. 311-334.
[88] Interim Report for Phase II – Task 5 of the Comprehensive Study to Understand Longitudinal ERW Seam Failures, "Summary Report for an Integrity Management Software Tool," May 2017. https://primis.phmsa.dot.gov/matrix/FilGet.rdm?fil=11469.
[89] ASTM International, ASTM STP 536, "Failure Stress Levels of Flaws in Pressurized Cylinders," 1973.
[90] American Petroleum Institute and American Society of Mechanical Engineers, API 579-1/ASME FFS-1, "Fitness-For-Service," Second Edition, June 2007.
[91] NACE International, NACE Corrosion 96 Paper 255, "Effect of Stress Corrosion Cracking on Integrity and Remaining Life of Natural Gas Pipelines," March 1996.
[92] Pipeline Research Council International, Inc., Topical Report NG-18 No. 193, "Development and Validation of a Ductile Flaw Growth Analysis for Gas Transmission Line Pipe," June 1991.

growth analysis to determine the remaining life of the pipeline. An ECA must use the techniques and procedures developed and confirmed through the research findings provided by PHMSA and other reputable technical sources for longitudinal seam and crack growth, such as the 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 online at: https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390. Operators wanting to use assumed Charpy v-notch toughness values differing from the prescribed values as a part of fracture mechanics analysis must notify PHMSA in accordance with § 192.18.

§ 192.750 Launcher and receiver safety.

PHMSA has determined that more explicit requirements are needed for safety when performing maintenance activities that use launchers and receivers to insert and remove maintenance tools and devices, as such facilities are subject to pipeline system pressures. The current regulations for hazardous liquid pipelines at 49 CFR part 195 have, since 1981, contained such safety requirements for scraper and sphere facilities (§ 195.426). However, the regulations for natural gas pipelines do not similarly require controls or instrumentation to protect against inadvertent breaches of system integrity due to the incorrect operation of launchers and receivers for ILI tools, scraper, and sphere facilities. Accordingly, this final rule is adding a new § 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.

§ 192.805 Qualification Program

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.805 to refer to the new § 192.18.

§ 192.909 How can an operator change its integrity management program?

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.909 to refer to the new § 192.18.

§ 192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

Section 29 of the 2011 Pipeline Safety Act requires operators to consider seismicity when evaluating threats. Accordingly, PHMSA is revising § 192.917(a)(3) to include seismicity of the area in evaluating the threat of outside force damage. To address NTSB recommendation P-11-15, PHMSA is also revising the criteria in § 192.917(e)(3) for addressing the threat of manufacturing and construction defects by requiring that a pipeline segment must have been pressure tested to a minimum of 1.25 times MAOP to conclude latent defects are stable. Section 192.917(e)(4) has additional requirements for the assessment of low-frequency ERW pipe with seam failures. It now requires usage of the appropriate technology to assess low-frequency ERW pipe, including seam cracking and selective seam weld corrosion. Pipe with seam 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 § 192.712.

Lastly, the integrity management requirements to address specific threats in § 192.917(e) include requirements for the major causes of pipeline incidents, such as corrosion, third-party damage, cyclic fatigue, manufacturing and construction defects, and electric resistance welded pipe. However, § 192.917(e) does not address cracks and crack-like defects. Therefore, PHMSA is adding a new paragraph, § 192.917(e)(6), to include specific IM requirements for addressing the threat of cracks and crack-like defects (including, but not limited to, stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) comparable to the other types of threats addressed in § 192.917(e).

§ 192.921 How is the baseline assessment to be conducted?

Section 192.921 requires that pipelines subject to the IM regulations have an integrity assessment. The current regulations allow operators to use ILI tools; 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 PG&E incident, PHMSA determined that the baseline assessment methods should be clarified and strengthened to emphasize ILI use 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 nor appropriate for the pipeline seam type and the threats to the pipeline. Therefore, this final rule requires that direct assessment only be allowed to assess the threats for which the specific direct assessment process is appropriate.

This final rule also adds three additional assessment methods for operators to use: (1) a "spike" hydrostatic pressure test, which is particularly well-suited to address time-dependent threats, such as stress corrosion cracking and other cracking or crack-like defects that can include manufacturing- and construction-related defects; (2) guided wave ultrasonic testing (GWUT), which is particularly appropriate in cases where short pipeline segments, such as road or railroad crossings, are difficult to assess; and (3) excavation with direct *in situ* examination. Based upon the threat assessed, examples of appropriate non-destructive examination methods for *in situ* examination can include ultrasonic testing, phased array ultrasonic testing, inverse wave field extrapolation, radiography, or magnetic particle inspection.

The current regulations indicate that ILI tools are an acceptable assessment method for the threats that the particular ILI tool type can assess. PHMSA is clarifying in this final rule that the use of ILI tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges, and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), and hard spots with cracking. As discussed above, this final 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-2005 when conducting in-line inspection of pipelines. Accordingly, PHMSA revises § 192.921(a)(1) in this final rule to require compliance with § 192.493 instead of ASME B31.8S for baseline ILI assessments for covered segments.

GWUT has been used 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 to use GWUT. In 2007, PHMSA developed guidelines for how it would evaluate notifications for the use of GWUT. These guidelines have been effectively used for over 9 years, and PHMSA has confidence that operators can use GWUT to assess the integrity of short segments of pipe against corrosion threats. In this final rule, PHMSA is incorporating these guidelines into a new Appendix F, which is referenced in § 192.921. Therefore, operators would no longer be required to notify PHMSA to use GWUT.

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 is clarifying its requirements to explicitly add excavation and direct *in situ* examination as an acceptable assessment method. As previously discussed under § 192.710, PHMSA intends for operators to assess non-HCA pipe with the same methods as HCA pipe. Therefore, PHMSA has standardized the assessment methods between both the IM and non-IM sections. Operators wishing to use “other technology” differing from the prescribed acceptable assessment methods must notify PHMSA in accordance with § 192.18.

§ 192.933 What actions must be taken to address integrity issues?

PHMSA is revising the Federal Pipeline Safety Regulations to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.933 to refer to the new § 192.18.

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

Section 29 of the 2011 Pipeline Safety Act requires operators to consider seismicity when evaluating threats. Accordingly, PHMSA is revising § 192.935(b)(2) to include seismicity of the area when evaluating preventive and mitigative measures with respect to the threat of outside force damage.

§ 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 pipeline segments and periodically evaluate the integrity of each covered pipeline segment. PHMSA determined that conforming amendments would be needed to implement, and be consistent with, the changes discussed above for § 192.921. Accordingly, this final rule requires that reassessments use the same assessment methods specified in § 192.921. Operators wishing to use "other technology" differing from the prescribed acceptable assessment methods must notify PHMSA in accordance with § 192.18.

§ 192.939 What are the required reassessment intervals?

Section 192.939 specifies reassessment intervals for pipelines subject to IM requirements. Section 5 of the 2011 Pipeline Safety 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 expects that any justification, at a minimum, must demonstrate that the extension does not pose a safety risk. In this final rule, PHMSA is codifying this technical correction.

As explained in PHMSA IM FAQ-41, the maximum interval for reassessment may be set using the specified number of calendar years. The use of calendar years is specific to gas pipeline reassessment interval years and does not alter the actual year interval requirements which appear elsewhere in the code for various inspection and maintenance requirements.

Additionally, PHMSA is revising § 192.939 to include a new § 192.18 that provides instructions for submitting notifications to PHMSA whenever required by part 192. PHMSA is making conforming changes to § 192.939 to refer to the new § 192.18.

§ 192.949 How does an operator notify PHMSA? (Removed and Reserved)

This rulemaking includes several requirements that allow operators to notify PHMSA of proposed alternative approaches to achieving the objective of the minimum safety standards. This is comparable to existing notification requirements in subpart O for pipelines subject to the

IM regulations. Because PHMSA is expanding the use of notifications to pipeline segments for which subpart O does not apply (i.e., to non-HCA pipeline segments), PHMSA is adding a new § 192.18 that contains the procedure for submitting such notifications. As such, § 192.949 is no longer needed and is being removed and reserved.

Appendix F to Part 192– Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

As discussed under § 192.921 above, a new Appendix F to part 192 is needed 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 applies GWUT technology in a manner that does not conform with the guidelines in Appendix F, it would be considered "other technology" for the purposes of §§ 192.710, 192.921, and 192.937.

VI. Standards Incorporated by Reference

A. Summary of New and Revised Standards

Consistent with the amendments in this document, PHMSA is incorporating by reference several standards as described below. Some of these standards are already incorporated by reference into the Federal Pipeline Safety Regulations and are being extended to other sections of the regulations. Other standards provide a technical basis for corresponding regulatory changes in this final rule.

- API STD 1163, "In-Line Inspection Systems Qualification," Second edition, April 2013, Reaffirmed August 2018.

This standard covers the use of ILI systems for onshore and offshore gas and hazardous liquid pipelines. This includes, but is not limited to, tethered, self-propelled, or free-flowing systems for detecting metal loss, cracks, mechanical damage, pipeline geometries, and pipeline location or mapping. The standard applies to both existing and developing technologies. This standard is an umbrella document that provides performance-based requirements for ILI systems, including procedures, personnel, equipment, and associated software. The incorporation of this standard into the Federal Pipeline Safety Regulations will provide rigorous processes for qualifying the equipment, people, processes, and software used in in-line inspections.

- ANSI/ASNT ILI-PQ-2005(2010), “In-line Inspection Personnel Qualification and Certification,” Reapproved October 11, 2010.

This standard establishes minimum requirements for the qualification and certification of in-line inspection personnel whose jobs demand specific knowledge of the technical principles of in-line inspection technologies, operations, regulatory requirements, and industry standards as those are applicable to pipeline systems. The employer-based standard includes qualification and certification for Levels I, II, and III. The incorporation of this standard into the Federal Pipeline Safety Regulations provides for certification and qualification requirements that are not otherwise addressed in part 192 and will promote a higher level of safety by establishing consistent standards to qualify the equipment, people, processes, and software used in in-line inspections.

- NACE Standard Practice 0102-2010, “In-Line Inspection of Pipelines,” Revised 2010-03-13.

This standard outlines a process of related activities that a pipeline operator can use to plan, organize, and execute an ILI project, and it includes guidelines pertaining to ILI data management and data analysis. This standard is intended for individuals and teams, including engineers, O&M personnel, technicians, specialists, construction personnel, and inspectors, involved in 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 used in in-line inspections.

PHMSA is also extending the applicability of the following three currently incorporated-by-reference standards to new sections of the Federal Pipeline Safety Regulations:

- ASME/ANSI B16.5-2003, “Pipe Flanges and Flanged Fittings,” October 2004, IBR approved for § 192.607(f).

This standard covers pressure-temperature ratings, materials, dimensions, tolerances, marking, testing, and methods of designating openings for pipe flanges and flanged fittings. The standard includes requirements and recommendations regarding flange bolting, flange gaskets, and flange joints. This standard is intended for manufacturers, owners, employers, users, and others concerned with the specification, buying, maintenance, training, and safe use of valves with pressure equipment. The incorporation of this standard promotes industry best practices and operational, cost, and safety benefits.

- ASME/ANSI B31G-1991 (Reaffirmed 2004), “Manual for Determining the Remaining Strength of Corroded Pipelines,” 2004, IBR approved for §§ 192.632(a) and 192.712(b).

This document provides guidance for the evaluation of metal loss in pressurized pipelines and piping systems. It is applicable to all pipelines and piping systems that are part of the scope of the transportation pipeline codes that are part of ASME B31 Code for Pressure Piping, namely: ASME B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids; ASME B31.8, Gas Transmission and Distribution Piping Systems; ASME B31.11, Slurry Transportation Piping Systems; and ASME B31.12, Hydrogen Piping and Pipelines, Part PL.

- AGA, Pipeline Research Committee Project, PR-3-805, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe,” (December 22, 1989), IBR approved for §§ 192.632(a) and 192.712(b).

This document was developed from the Modified B31G method to allow assessment of a river bottom profile of a corroded area on a pipeline to provide more accurate predictions of the pipeline’s remaining strength, and it was adapted into a software program known as RSTRENG. Pipeline operators can use RSTRENG to calculate a pipeline’s predicted failure pressure and safe pressure when determining operating pressures and anomaly response times.

The incorporation by reference of ASME/ANSI B31.8S was approved for §§ 192.921 and 192.937 as of January 14, 2004. That approval is unaffected by the section revisions in this final rule.

B. 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 (SDO). In general, SDOs update and revise their published standards every 2 to 5 years to reflect modern technology and best technical practices. ASTM often updates some of its more widely used standards every year, and sometimes multiple editions of standards are published in a given year.

In accordance with the National Technology Transfer and Advancement Act of 1995 (Pub. L. 104-113), PHMSA has the responsibility for determining 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 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 of that law 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 website." 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 website." 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.

On November 7, 2014, the Office of the Federal Register issued a final rule that revised 1 CFR 51.5 to require that Federal agencies include a discussion in the preamble of the final rule "the ways the materials it incorporates by reference are reasonably available to interested parties and how interested parties can obtain the materials." 79 FR 66278. In relation to this rulemaking, PHMSA has contacted each SDO and has requested free public access of each standard that has been incorporated by reference. The SDOs agreed to make viewable copies of the incorporated standards available to the public at no cost. Pipeline operators interested in purchasing these standards can contact the individual and applicable standards organizations. The contact information is provided in this rulemaking action, see § 192.7.

In addition, PHMSA will provide individual members of the public temporary access to any standard that is incorporated by reference that is not otherwise available for free. Requests for access can be sent to the following email address: PHMSAPHPStandards@dot.gov.

VII. Regulatory Analysis and Notices

A. Statutory/Legal Authority for this Rulemaking

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

PHMSA is revising the "Authority" entry for parts 191 and 192 to include a citation to a provision of the Mineral Leasing Act (MLA), specifically, 30 U.S.C. § 185(w)(3). Section 185(w)(3) provides that "[p]eriodically, but at least once a year, the Secretary of the Department of Transportation shall cause the examination of all pipelines and associated facilities on Federal lands and shall cause the prompt reporting of any potential leaks or safety problems." The Secretary has delegated this responsibility to PHMSA (49 CFR 1.97). PHMSA has traditionally complied with § 185(w)(3) through the issuance of its pipeline safety regulations, which require annual examinations and prompt reporting for all or most of the pipelines they cover. PHMSA is making this change to be consistent with and make clear its long-standing position that the agency complies with the MLA through the issuance of pipeline safety regulations.

B. Executive Orders 12866 and 13771, and DOT Regulatory Policies and Procedures

Executive Order 12866 requires agencies to regulate in the "most cost-effective manner," to make a "reasoned determination that the benefits of the intended regulation justify its costs," and to develop regulations that "impose the least burden on society." This action has been determined to be significant under Executive Order 12866. It is also considered significant under the Regulatory Policies and Procedures of the Department of Transportation because of substantial congressional, State, industry, and public interest in pipeline safety. The final rule has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866 (Regulatory Planning and Review) and is consistent with the Executive Order 12866 requirements and 49 U.S.C. 60102(b)(5)-(6). Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*, the Office of Information and Regulatory Affairs designated this rule as not a "major rule," as defined by 5 U.S.C. 804(2). This final rule is considered an Executive Order 13771 regulatory action. Details on the estimated costs of this final rule can be found in the rule's RIA.

The table below summarizes the annualized costs for the provisions in the final rule. These estimates reflect the timing of the compliance actions taken by operators and are annualized, where applicable, over 21 years and discounted to 2017 using rates of 3 percent and 7 percent. PHMSA estimates incremental costs for the final requirements in Section 5 of the

RIA. PHMSA finds that the other final rule requirements will not result in an incremental cost. Additionally, PHMSA did not quantify the cost savings from the material properties verification provisions under this final rule compared to the existing regulations. The costs of this final rule reflect incremental integrity assessments, MAOP reconfirmation actions, and ILI launcher and receiver upgrades; PHMSA estimates the annualized cost of this rule is $32.7 million at a 7 percent discount rate.

Summary of Annualized Costs, 2019 – 2039 ($2017 thousands)

Provision	Annualized Cost	
	3% Discount Rate	7% Discount Rate
1. MAOP Reconfirmation & Material Properties Verification	$25.9	$27.9
2. Seismicity	0	0
3. Six-Month Grace Period for Seven Calendar-Year Reassessment Intervals	0	0
4. In-Line Inspection Launcher/Receiver Safety	$0.03	$0.04
5. MAOP Exceedance Reports	0	0
6. Strengthening Requirements for Assessment Methods	0	0
7. Assessments Outside HCAs	$5.48	$4.71
8. Related Records Provisions	0	0
Total	**$31.4**	**$32.7**

The benefits of the final rule will depend on the degree to which compliance actions result in additional safety measures, relative to the current baseline, and the effectiveness of these measures in preventing or mitigating future pipeline releases or other incidents. For the final rule RIA, PHMSA did not monetize benefits. The rule’s benefits are discussed qualitatively instead.

For more information, please see the RIA in the docket for this rulemaking.

C. 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 a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the Administrative Procedure Act unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities. PHMSA prepared a FRFA which is available in the docket for the rulemaking.

D. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

PHMSA analyzed this final rule per the principles and criteria in Executive Order 13175, "Consultation and Coordination with Indian Tribal Governments." Because this final 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.

E. 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. On April 18, 2016, PHMSA published an NPRM seeking public comments on the revision of the Federal Pipeline Safety Regulations applicable to the safety of gas transmission pipelines and gas gathering pipelines. During that time, PHMSA proposed changes to information collections that are no longer included in this final rule. PHMSA determined it would be more effective to advance a rulemaking that focuses on the mandates from the 2011 Pipeline Safety Act and split out the other provisions contained in the NPRM into two other separate rules. As such, PHMSA has removed all references to those collections previously contained in the NPRM and will submit information collection revision requests to OMB based on the requirements solely contained within this final rule.

PHMSA estimates that the proposals in this final rule will impact the information collections described below. These information collections are contained in the PSR, 49 CFR parts 190–199. The following information is provided for each information collection: (1) Title of the information collection, (2) OMB control number, (3) Current expiration date, (4) Type of request, (5) Abstract of the information collection activity, (6) Description of affected public, (7) Estimate of total annual reporting and recordkeeping burden, and (8) Frequency of collection. The information collection burden for the following information collections are estimated to be revised as follows:

1. Title: Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137-0049.

Current Expiration Date: 09/30/2021.

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, 25 new recordkeeping requirements are being added to the pipeline safety regulations for owners and operators of natural gas pipelines. Therefore, PHMSA expects to add 24,609 responses and 3,740 hours to this information collection because of the provisions in this final rule.

<u>Affected Public</u>: Natural Gas Pipeline Operators

<u>Annual Reporting and Recordkeeping Burden:</u>

Total Annual Responses: 3,861,470.

Total Annual Burden Hours: 1,674,810.

<u>Frequency of Collection</u>: On occasion.

<u>2. Title</u>: Notification Requirements for Gas Transmission Pipeline Operators.

<u>OMB Control Number</u>: New Collection. Will Request from OMB.

<u>Current Expiration Date:</u> TBD.

<u>Abstract:</u> A person owning or operating a natural gas pipeline facility is required to provide information to the Secretary of Transportation at the Secretary's request. Based on the proposed revisions in this rule, 10 new notification requirements are being added to the pipeline safety regulations for owners and operators of natural gas pipelines. Therefore, PHMSA expects to add 721 responses and 1,070 hours because of the notification requirements in this final rule.

<u>Affected Public</u>: Gas Transmission operators.

<u>Annual Reporting and Recordkeeping Burden:</u>

Total Annual Responses: 721.

Total Annual Burden Hours: 1,070.

<u>Frequency of Collection</u>: On occasion.

3. Title: Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137-0522.

Current Expiration Date: 8/31/2020.

Abstract: This information collection covers the collection of annual report data from natural gas pipeline operators. PHMSA is revising the Gas Transmission and Gas Gathering Annual Report (form PHMSA F7 100.2-1) to collect additional information including mileage of pipe subject to the MAOP reconfirmation and MCA criteria. Based on the proposed revisions, PHMSA estimates that the Annual Report will take an additional 5 hours per report to complete to include the newly required data, increasing the burden for each report to 47 burden hours for an overall burden increase of 7,200 burden hours across all operators.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 10,852

Total Annual Burden Hours: 83,151.

Frequency of Collection: On occasion.

4. Title: Incident for Natural Gas Pipeline Operators.

OMB Control Number: 2137-0635.

Current Expiration Date: 4/30/2022.

Abstract: This information collection covers the collection of incident report data from natural gas pipeline operators. PHMSA is revising the Gas Transmission Incident Report to have operators indicate whether incidents occur inside Moderate

Consequence Areas. PHMSA does not expect there to be an increase in burden for the reporting of Gas Transmission incident data.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 301

Total Annual Burden Hours: 3,612.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue, S.E., 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.

Those desiring to comment on these information collections should send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street, N.W., Washington, D.C. 20503. Comments should be submitted on or prior to October 31, 2019. Comments may also be sent via e-mail to the Office of Management and Budget at the following address: oira_submissions@omb.eop.gov. OMB is required to make a decision concerning the collection of information requirements contained in this final rule between 30 and 60 days after publication of this document in the Federal Register. Therefore, a comment to OMB is best assured of having its full effect if received within 30 days of publication.

F. Unfunded Mandates Reform Act of 1995

An evaluation of Unfunded Mandates Reform Act (UMRA) considerations is performed as part of the Final Regulatory Impact Assessment. PHMSA determined that this final rule does not impose enforceable duties on State, local, or tribal governments or on the private sector of $100 million or more, adjusted for inflation, in any one year and therefore does not have implications under Section 202 of the UMRA of 1995. A copy of the RIA is available for review in the docket.

G. National Environmental Policy Act

PHMSA analyzed this final rule in accordance with the National Environmental Policy Act (42 U.S.C. 4332) and determined this action will not significantly affect the quality of the human environment. The Environmental Assessment for this final rule is in the docket.

H. Executive Order 13132: Federalism

PHMSA analyzed this final rule in accordance with Executive Order 13132 (“Federalism”). The final 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 rulemaking action does not impose substantial direct compliance costs on State and local governments. The pipeline safety laws, specifically 49 U.S.C. 60104(c), prohibits State safety regulation of interstate pipelines. Under the pipeline safety law, States have the ability to augment pipeline safety requirements for intrastate pipelines regulated by PHMSA, but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility PHMSA does not regulate. It is these statutory provisions, not the rule, that govern preemption of State law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

I. Executive Order 13211

This final 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 final rule as a significant energy action.

J. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement, published on April 11, 2000 (65 FR

19476), in the Federal Register at: ***https://www.govinfo.gov/content/FR-2000-04-11/pdf/00-8505.pdf***.

K. Regulation Identifier Number (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

MAOP exceedance, Pipeline reporting requirements.

49 CFR part 192

Incorporation by reference, Integrity assessments, Material properties verification, MAOP reconfirmation, Pipeline safety, Predicted failure pressure, Recordkeeping, Risk assessment, Safety devices.

In consideration of the foregoing, PHMSA is amending 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: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et. seq.*, and 49 CFR 1.97.

2. In § 191.23, paragraph (a)(6) is revised, paragraph (a)(10) is added, and paragraph (b)(4) is revised to read as follows:

§ 191.23 Reporting safety-related conditions.

(a) * * *

(6) Any malfunction or operating error that causes the pressure – plus the margin (build-up) allowed for operation of pressure limiting or control devices – to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an underground natural gas storage facility, or the maximum allowable working pressure of an LNG facility that contains or processes gas or LNG.

* * * * *

(10) For transmission pipelines only, 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 the applicable requirements of §§ 192.201, 192.620(e), and 192.739. The reporting requirement of this paragraph (a)(10) is not applicable to gathering lines, distribution lines, LNG facilities, or underground natural gas storage facilities (*See* paragraph (a)(6) of this section).

(b) * * *

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report. Notwithstanding this exception, a report must be filed for:

(i) Conditions under paragraph (a)(1) of this section, unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline; and

(ii) Any condition under paragraph (a)(10) of this section.

* * * * *

3. 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 (9) must be filed (received by the Associate Administrator) in writing within 5 working days (not including Saturday, Sunday, or Federal holidays) after the day a representative of an operator first determines that the condition exists, but not later than 10 working days after the day a representative of an operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reporting methods and report requirements are described in paragraph (c) of this section.

(b) Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in § 191.23(a)(10) for a gas transmission pipeline must be filed (received by the Associate Administrator) in writing within 5 calendar days of the exceedance using the reporting methods and report requirements described in paragraph (c) of this section.

(c) Reports must be filed by email to InformationResourcesManager@dot.gov or by facsimile to (202) 366-7128. For a report made pursuant to § 191.23(a)(1) through (9), the report must be headed "Safety-Related Condition Report." For a report made pursuant to

§ 191.23(a)(10), the report must be headed "Maximum Allowable Operating Pressure Exceedances." All reports must provide the following information:

(1) Name, principal address, and operator identification number (OPID) of the 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 or future corrective action, including the anticipated schedule for starting and concluding such action.

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

4. The authority citation for part 192 is revised to read as follows:

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

5. In § 192.3, the definitions for "Engineering critical assessment (ECA)" and "Moderate consequence area" are added in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

Engineering critical assessment (ECA) means a documented 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 based upon the pipeline segment maximum allowable operating pressure.

* * * * *

Moderate consequence area means:

(1) An onshore area that is within a potential impact circle, as defined in § 192.903, containing either:

(i) Five or more buildings intended for human occupancy; or

(ii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1* (see: https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf), and that does not meet the definition of high consequence area, as defined in § 192.903.

(2) 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 containing either 5 or more buildings intended for human occupancy; or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either 5 or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.

* * * * *

6. In § 192.5, paragraph (d) is added to read as follows:

§ 192.5 Class locations.

* * * * *

(d) An operator must have records that document the current class location of each pipeline segment and that demonstrate how the operator determined each current class location in accordance with this section.

7. Amend § 192.7 as follows:

a. Revise paragraph (a)(1)(ii);

b. Add paragraph (b)(12);

c. Revise paragraphs (c)(2) and (4);

d. Re-designate paragraphs (d) through (j) as paragraphs (e) through (k), respectively;

e. Add new paragraphs (d) and (h)(2); and

f. Revise newly redesignated paragraph (j)(1).

The revisions and additions read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

(a) * * *

(1) * * *

(ii) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email fedreg.legal@nara.gov or go to www.archives.gov/federal-register/cfr/ibr-locations.html.

(b) * * *

(12) API STANDARD 1163, "In-Line Inspection Systems Qualification," Second edition, April 2013, Reaffirmed August 2018, (API STD 1163), IBR approved for § 192.493.

(c) * * *

(2) ASME/ANSI B16.5-2003, "Pipe Flanges and Flanged Fittings," October 2004, (ASME/ANSI B16.5), IBR approved for §§ 192.147(a), 192.279, and 192.607(f).

* * * * *

(4) ASME/ANSI B31G-1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ANSI B31G), IBR approved for §§ 192.485(c), 192.632(a), 192.712(b), and 192.933(a).

* * * * *

(d) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH, 43228, phone: 800-222-2768, website: https://www.asnt.org/.

(1) ANSI/ASNT ILI-PQ-2005(2010), "In-line Inspection Personnel Qualification and Certification," Reapproved October 11, 2010, (ANSI/ASNT ILI-PQ), IBR approved for § 192.493.

(2) [Reserved]

*   *   *   *   *

(h)   *   *   *

(2) NACE Standard Practice 0102-2010, "In-Line Inspection of Pipelines," Revised 2010-03-13, (NACE SP0102), IBR approved for §§ 192.150(a) and 192.493.

*   *   *   *   *

(j)   *   *   *

(1) AGA, Pipeline Research Committee Project, PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR-3-805 (R-STRENG)), IBR approved for §§ 192.485(c); 192.632(a); 192.712(b); 192.933(a) and (d).

*   *   *   *   *

8. In § 192.9, paragraphs (b), (c), and (d)(1), (2), and (6) are revised to read as follows:

§ 192.9 What requirements apply to gathering lines?

*   *   *   *   *

(b) Offshore lines. An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.150, 192.285(e), 192.493, 192.506, 192.607, 192.619(e), 192.624, 192.710, 192.712, and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.150, 192.285(e), 192.493, 192.506, 192.607, 192.619(e), 192.624, 192.710, 192.712, and in subpart O of this part. However, operators of Type A regulated onshore gathering lines 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) * * *

(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 except the requirements in §§ 192.67, 192.127, 192.205, 192.227(c), 192.285(e), and 192.506;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except the requirements in § 192.493;

* * * * *

(6) Establish the MAOP of the line under § 192.619(a), (b), and (c);

* * * * *

9. Section 192.18 is added to read as follows:

§ 192.18 How to notify PHMSA.

(a) An operator must provide any notification required by this part by—

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

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

(b) An operator must also notify the appropriate State or local pipeline safety authority when an applicable pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate applicable pipeline segment is regulated by that State.

(c) Unless otherwise specified, if the notification is made pursuant to § 192.506(b), § 192.607(e)(4), § 192.607(e)(5), § 192.624(c)(2)(iii), § 192.624(c)(6), § 192.632(b)(3), § 192.710(c)(7), § 192.712(d)(3)(iv), § 192.712(e)(2)(i)(E), §192.921(a)(7), or § 192.937(c)(7) to use a different integrity assessment method, analytical method, sampling approach, or technique (*i.e.*, "other technology") that differs from that prescribed in those sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct its review.

§ 192.67 [Redesignated as §192.69]

10. Redesignate § 192.67 as § 192.69.

11. Section 192.67 is added to read as follows:

§ 192.67 Records: Material properties.

(a) For steel transmission pipelines installed after **[July 1, 2020**, an operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with §§ 192.53 and 192.55. Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.

(b) For steel transmission pipelines installed on or before **July 1, 2020]**, if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with §§ 192.53 and 192.55, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before **July 1, 2020]**, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

12. Section 192.127 is added to read as follows:

§ 192.127 Records: Pipe design.

(a) For steel transmission pipelines installed after **July 1, 2020]**, an operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with § 192.103 and documenting that the determination of design pressure for the pipe is made in accordance with § 192.105.

(b) For steel transmission pipelines installed on or before **July 1, 2020**, if operators have records documenting pipe design and the determination of design pressure in accordance with §§ 192.103 and 192.105, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before **July 1, 2020**, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

13. 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 NACE SP0102, section 7 (incorporated by reference, *see* § 192.7).

*   *   *   *   *

14. Section 192.205 is added to read as follows:

§ 192.205 Records: Pipeline components.

(a) For steel transmission pipelines installed after **July 1, 2020**, an operator must collect or make, and retain for the life of the pipeline, 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 (X42) or greater and with nominal diameters of greater than 2 inches must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.

(b) For steel transmission pipelines installed on or before **July 1, 2020**, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before **July 1, 2020**, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

15. In § 192.227, paragraph (c) is added to read as follows:

§ 192.227 Qualification of welders.

*   *   *   *   *

(c) For steel transmission pipe installed after **July 1, 2021**, records demonstrating each individual welder qualification at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

16. In § 192.285, paragraph (e) is added to read as follows:

§ 192.285 Plastic pipe: Qualifying persons to make joints.

*   *   *   *   *

(e) For transmission pipe installed after July 1, 2021, records demonstrating each person's plastic pipe joining qualifications at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

17. Section 192.493 is added to read as follows:

§ 192.493 In-line inspection of pipelines.

When conducting in-line inspections of pipelines required by this part, an operator must comply with API STD 1163, ANSI/ASNT ILI-PQ, and NACE SP0102, (incorporated by reference, *see* § 192.7). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable.

18. Section 192.506 is added to read as follows:

§ 192.506 Transmission lines: Spike hydrostatic pressure test.

(a) *Spike test requirements.* Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of 30 percent or more of SMYS is spike tested under this part, the spike hydrostatic pressure test must be conducted in accordance with this section.

(1) The test must use water as the test medium.

(2) The baseline test pressure must be as specified in the applicable paragraphs of § 192.619(a)(2) or § 192.620(a)(2), whichever applies.

(3) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505.

(4) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS. This spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes.

(b) *Other technology or other technical evaluation process.* Operators may use other technology or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA 90 days in advance of the assessment or reassessment requirements of this subchapter. The notification must be made in accordance with § 192.18 and must include the following information:

(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;

(2) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, 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 pipeline 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 qualified technical subject matter expert.

19. In § 192.517, paragraph (a) introductory text is revised to read as follows:

§ 192.517 Records: Tests.

(a) An 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:

*   *   *   *   *

20. Section 192.607 is added to read as follows:

§ 192.607 Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.

(a) *Applicability*. Wherever required by this part, operators of onshore steel transmission pipelines must document and verify material properties and attributes in accordance with this section.

(b) *Documentation of material properties and attributes.* Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (*e.g.*, yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method at § 192.624(c)(3) or the fracture mechanics requirements at § 192.712 must be maintained for the life of the pipeline.

(c) *Verification of material properties and attributes*. If an operator does not have traceable, verifiable, and complete records required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:

(1) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.

(2) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.

(3) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.

(4) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.

(5) Verification of material properties and attributes for non-line pipe components must comply with paragraph (f) of this section.

(d) *Special requirements for nondestructive Methods*. Procedures developed in accordance with paragraph (c) of this section for verification of material properties and attributes using nondestructive methods must:

(1) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;

(2) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and

(3) Use test equipment that has been properly calibrated for comparable test materials prior to usage.

(e) *Sampling multiple segments of pipe*. To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:

(1) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.

(2) For each population defined according to paragraph (e)(1) of this section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to § 192.614, until completion of the lesser of the following:

(i) One excavation per mile rounded up to the nearest whole number; or

(ii) 150 excavations if the population is more than 150 miles.

(3) Prior tests conducted for a single excavation according to the requirements of paragraph (c) of this section may be counted as one sample under the sampling requirements of this paragraph (e).

(4) If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with § 192.18.

(5) An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (e)(2) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.

(f) *Components*. For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (c) of this section for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5 (incorporated by reference, *see* § 192.7)),

(1) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.

(2) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:

(i) Larger than 2 inches in nominal outside diameter,

(ii) Material grades of 42,000 psi (Grade X-42) or greater, or

(iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

(3) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.

(g) *Uprating*. The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of 24,000 psi in accordance with § 192.107(b)(2).

21. In § 192.619, the introductory text of paragraphs (a) introductory text and (a)(2) and (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) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:

* * * * *

(2) The pressure obtained by dividing the pressure to which the pipeline 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 psi (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the Table 1 to paragraph (a)(2)(ii):

Table 1 to paragraph (a)(2)(ii)

		Factors [1], segment—		
Class location	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970) and before **July 1, 2020**	Installed on or after **July 1, 2020**	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 pipeline segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline 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.

*   *   *   *   *

(4) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with § 192.607, if applicable, and the history of the pipeline segment, including known corrosion and actual operating pressure.

*   *   *   *   *

(e) Notwithstanding the requirements in paragraphs (a) through (d) of this section, operators of 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.

(f) Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs (a) through (e) of this section as follows:

(1) Operators of pipelines in operation as of **[July 1, 2020** must retain any existing records establishing MAOP for the life of the pipeline;

(2) Operators of pipelines in operation as of **July 1, 2020** that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with § 192.624, must retain the records reconfirming MAOP for the life of the pipeline; and

(3) Operators of pipelines placed in operation after **July 1, 2020** must make and retain records establishing MAOP for the life of the pipeline.

22. Section 192.624 is added to read as follows:

§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

(a) *Applicability.* Operators of onshore steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this section if either of the following conditions are met:

(1) Records necessary to establish the MAOP in accordance with § 192.619(a), including records required by § 192.517(a), are not 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.

(2) The pipeline segment's MAOP was established in accordance with § 192.619(c), the pipeline segment's MAOP is greater than or equal to 30 percent of the specified minimum yield strength, and the pipeline segment 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 pipeline segment can accommodate inspection by means of instrumented inline inspection tools.

(b) *Procedures and completion dates.* Operators of a pipeline subject to this section must develop and document procedures for completing all actions required by this section by **July 1, 2021**. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition of § 192.624(a), and for performing a spike test or material verification in accordance with §§ 192.506 and 192.607, if applicable. All actions required by this section must be completed according to the following schedule:

(1) Operators must complete all actions required by this section on at least 50% of the pipeline mileage by**July 3, 2028.**

(2) Operators must complete all actions required by this section on 100% of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of § 192.624(a) (*e.g.*, due to a location becoming a high consequence area), whichever is later.

(3) If operational and environmental constraints limit an operator from meeting the deadlines in § 192.624, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with § 192.18. The notification must include an up-to-date plan for completing all actions in accordance with this section, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and any needed temporary measures needed to mitigate the impact on safety.

(c) *Maximum allowable operating pressure determination.* Operators of a pipeline segment meeting a condition in paragraph (a) of this section must reconfirm its MAOP using one of the following methods:

(1) *Method 1: Pressure test.* Perform a pressure test and verify material properties records in accordance with § 192.607 and the following requirements:

(i) *Pressure test.* Perform a pressure test in accordance with subpart J of this part. The MAOP must 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).

(ii) *Material properties records.* Determine if the following material properties records are documented in traceable, verifiable, and complete records: diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).

(iii) *Material properties verification.* If any of the records required by paragraph (c)(1)(ii) of this section are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with § 192.607. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with § 192.607.

(2) *Method 2: Pressure Reduction.* Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in § 192.619(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 upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (*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 records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:

(A) For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding **October 1, 2019**, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4.

(B) For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding **October 1, 2019**, divided by 2.00.

(ii) Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is established using Method 2.

(iii) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with § 192.18 no later than 7 calendar days after establishing the reduced MAOP. 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 § 192.712;

(C) Justification that establishing MAOP by another method allowed by this section is impractical;

(D) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance § 192.607, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and

(E) Planned duration for operating at the requested MAOP, 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.

(3) *Method 3: Engineering Critical Assessment (ECA)*. Conduct an ECA in accordance with § 192.632.

(4) *Method 4: Pipe Replacement*. Replace the pipeline segment in accordance with this part.

(5) *Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius*. Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows:

(i) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during 5 years preceding **October 1, 2019**, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient (*i.e.*, the location specific operating pressure at each location);

(ii) Conduct patrols in accordance with § 192.705 paragraphs (a) and (c) and conduct instrumented leakage surveys in accordance with § 192.706 at intervals not to exceed those in the following table 1 to § 192.624(c)(5)(ii):

Table 1 to **§ 192.624(c)(5)(ii)**

Class Locations	Patrols	Leakage Surveys
(A) Class 1 and Class 2	3 ½ months, but at least four times each calendar year	3 ½ months, but at least four times each calendar year
(B) Class 3 and Class 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year

(iii) Under Method 5, future uprating of the pipeline segment in accordance with subpart K is allowed.

(6) *Method 6: Alternative Technology*. Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with § 192.18. The notification must include descriptions of the following details:

(i) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated;

(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;

(iii) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;

(iv) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;

(v) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, 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 § 192.712;

(vi) Operational monitoring procedures;

(vii) Methodology and criteria used to justify and establish the MAOP; and

(vii) Documentation of the operator’s process and procedures used to implement the use of the alternative technology, including any records generated through its use.

(d) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

23. Section 192.632 is added to read as follows:

§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines.

When an operator conducts an MAOP reconfirmation in accordance with § 192.624(c)(3) "Method 3" using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this section. The ECA must assess: threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline.

(a) *ECA Analysis.* (1) The material properties required to perform an ECA analysis in accordance with this paragraph are as follows: diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform an ECA for any pipeline segment in accordance with this paragraph are not documented in traceable, verifiable and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with § 192.607. The ECA must integrate, analyze, and account for the material properties, 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 close interval surveys, coating surveys, interference surveys required by subpart I of this part, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by §§ 192.617, 192.710, and subpart O of this part.

(2) The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:

(i) 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 of each defect in accordance with § 192.712.

(ii) 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. ASME/ANSI B31G (incorporated by reference, *see* § 192.7) or R-STRENG (incorporated by reference, *see* § 192.7) must be used for corrosion defects. Both procedures and their analysis 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).

(iii) When determining the predicted failure pressure 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 and documented.

(iv) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 p.s.i. or determine the material properties using § 192.607.

(3) The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. 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.

(4) The MAOP must be established at the lowest predicted failure pressure 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).

(b) *Assessment to determine defects remaining in the pipe*. An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with paragraph (a) of this section.

(1) An operator may use a previous pressure test that complied with subpart J to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of subpart J of this part exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the date of the pressure test in accordance with § 192.712. The ECA must analyze the predicted size of the largest defect that could have survived the pressure test that could remain in the pipe at the time the ECA is performed. The operator must calculate the remaining life of the most severe defects that could have survived the pressure test and establish a re-assessment interval in accordance with the methodology in § 192.712.

(2) Operators may use an inline inspection program in accordance with paragraph (c) of this section.

(3) Operators may use “other technology” if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use “other technology” in the

ECA, it must notify PHMSA in advance of using the other technology in accordance with § 192.18. The “other technology” notification must have:

(i) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and

(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered.

(c) *In-line inspection*. An inline inspection (ILI) program to determine the defects remaining the pipe for the ECA analysis must be performed 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.

(1) If a pipeline has 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.

(2) If the pipeline has had a reportable incident, as defined in § 191.3, 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 this section includes an engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses.

(3) Inline inspection must be performed in accordance with § 192.493.

(4) An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction

related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and following up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data, or both.

(5) 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 and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types 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.

(6) Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in §§ 192.713 and 192.933.

(d) *Defect remaining life.* If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with § 192.712.

(e) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

24. Section 192.710 is added to read as follows:

§ 192.710 Transmission lines: Assessments outside of high consequence areas.

(a) *Applicability*: This section applies to onshore steel transmission pipeline segments with a maximum allowable operating pressure of greater than or equal to 30% of the specified minimum yield strength and are located in:

(1) A Class 3 or Class 4 location; or

(2) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (*i.e.*, "smart pig").

(3) This section does not apply to a pipeline segment located in a high consequence area as defined in § 192.903.

(b) *General*—(1) *Initial assessment.* An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than **July 3, 2034,** or as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of § 192.710(a) (*e.g.,* due to a change in class location or the area becomes a moderate consequence area), whichever is later.

(2) *Periodic reassessment.* An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.

(3) *Prior assessment.* An operator may use a prior assessment conducted before **July 1, 2020** as an initial assessment for the pipeline segment, if the assessment met the subpart O

requirements of part 192 for in-line inspection at the time of the assessment. 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)(2) of this section calculated from the date of the prior assessment.

(4) *MAOP verification.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) for establishing MAOP may be used as an initial assessment or reassessment under this section.

(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 segment is susceptible and must be performed using one or more of the following methods:

(1) *Internal inspection.* Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible, such as corrosion, deformation and mechanical damage (*e.g.*, dents, gouges and grooves), material cracking and crack-like defects (*e.g.*, 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;

(2) *Pressure test.* Pressure test conducted in accordance with subpart J of this part. The use of subpart J 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; and stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage;

(3) *Spike hydrostatic pressure test.* A spike hydrostatic pressure test conducted in accordance with § 192.506. A spike hydrostatic pressure test is appropriate for time-dependent 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) *Direct examination.* 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 applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

(5) *Guided Wave Ultrasonic Testing.* Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;

(6) *Direct assessment.* Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. 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 and 192.929; or

(7) *Other technology*. 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 must notify PHMSA in advance of using the other technology in accordance with § 192.18.

(d) *Data analysis*. An operator must analyze and account for the data obtained from an assessment performed under paragraph (c) of this section to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (*e.g.*, 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.

(e) *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. 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 180 days is impracticable.

(f) *Remediation*. An operator must comply with the requirements in §§ 192.485, 192.711, and 192.713, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

(g) *Analysis of information*. An operator must analyze and account for all available relevant information about a pipeline in complying with the requirements in paragraphs (a) through (f) of this section.

25. Section 192.712 is added to read as follows:

§ 192.712 Analysis of predicted failure pressure.

(a) *Applicability*. Whenever required by this part, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this section.

(b) *Corrosion metal loss*. When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R-STRENG (incorporated by reference, *see* § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

(c) [Reserved]

(d) *Cracks and crack-like defects*—(1) *Crack analysis models*. When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).

(2) *Analysis for crack growth and remaining life.* If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must

calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.

(i) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph (e)(2) of this section must be used.

(ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).

(iii) An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment 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.

(3) *Cracks that survive pressure testing*. For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in paragraph (d)(1) of this section. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v- notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:

(i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(ii) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in § 192.607;

(iii) A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.; or

(iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with § 192.18.

(e) *Data.* In performing the analyses of predicted or assumed anomalies or defects in accordance with this section, an operator must use data as follows.

(1) An operator must explicitly analyze and account for uncertainties in reported assessment results (including 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 the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using *in situ* direct measurements.

(2) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator shall use conservative assumptions as follows:

(i) *Material toughness*. An operator must use one of the following for material toughness:

(A) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(B) A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607;

(C) If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects;

(D) If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or

(E) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with § 192.18 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions.

(ii) *Material strength.* An operator must assume one of the following for material strength:

(A) Grade A pipe (30,000 psi), or

(B) The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.

(iii) *Pipe dimensions and other data*. Until pipe wall thickness, diameter, or other data are determined and documented in accordance with § 192.607, the operator must use values upon which the current MAOP is based.

(f) *Review.* Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.

(g) *Records.* An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section. Records must document justifications, deviations, and determinations made for the following, as applicable:

(1) The technical approach used for the analysis;

(2) All data used and analyzed;

(3) Pipe and weld properties;

(4) Procedures used;

(5) Evaluation methodology used;

(6) Models used;

(7) Direct in situ examination data;

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

(9) Pressure test data and results;

(10) In-the-ditch assessments;

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

(12) All finite element analysis results;

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

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

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

(16) Reassessment time interval and safety factors;

(17) The date of the review;

(18) Confirmation of the results by qualified technical subject matter experts; and

(19) Approval by responsible operator management personnel.

26. Section 192.750 is added to read as follows:

§ 192.750 Launcher and receiver safety.

Any launcher or receiver used after **July 1, 2021**, 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. An operator must use a device to either: indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (*e.g.* inspection tools, scrapers, or spheres), if pressure has not been relieved.

27. In § 192.805, paragraph (i) is revised to read as follows:

§ 192.805 Qualification Program.

*   *   *   *   *

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if an operator significantly modifies the program after the administrator or state agency has verified that it complies with this section. Notifications to PHMSA must be submitted in accordance with § 192.18.

28. In § 192.909, paragraph (b) is revised to read as follows:

§ 192.909 How can an operator change its integrity management program?

*   *   *   *   *

(b) *Notification*. An operator must notify OPS, in accordance with § 192.18, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must provide notification within 30 days after adopting this type of change into its program.

29. In § 192.917, paragraphs (a)(3) and (e)(2) through (4) are revised, and paragraph (e)(6) is added 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)   *   *   *

(3) Time independent threats such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage to include consideration of seismicity, geology, and soil stability of the area; and

*   *   *   *   *

(e)   *   *   *

(2) *Cyclic fatigue.* An operator must analyze and account for whether cyclic fatigue or other loading conditions (including ground movement, and 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 analysis 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 analysis together with the criteria used to determine the significance of the threat(s) to the covered segment to prioritize the integrity baseline assessment or reassessment. Failure stress pressure and crack growth analysis of cracks and crack-like defects must be conducted in accordance with § 192.712. An operator must monitor operating pressure cycles and periodically, but at least every 7 calendar years, with intervals not to exceed 90 months, determine if the cyclic fatigue analysis remains valid or if the cyclic fatigue analysis must be revised based on changes to operating pressure cycles or other loading conditions.

(3) *Manufacturing and construction defects.* An operator must analyze the covered segment to determine and account for the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment. The analysis must account for 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 at least 1.25 times MAOP, and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent subpart J 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.

(i) The pipeline segment has experienced a reportable incident, as defined in § 191.3, since its most recent successful subpart J pressure test, due to an original manufacturing-related defect, or a construction-, installation-, or fabrication-related defect;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *Electric Resistance Welded* (*ERW) pipe.* If a covered pipeline segment contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint 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 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 5 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 seam 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 § 192.712.

*   *   *   *   *

(6) *Cracks*. If an operator identifies any crack or crack-like defect (*e.g.*, stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) on a covered pipeline segment that could adversely affect the integrity of the pipeline, the operator must evaluate, and remediate, as

necessary, all pipeline segments (both covered and non-covered) with similar characteristics associated with the crack or crack-like defect. Similar characteristics may include operating and maintenance histories, material properties, and environmental characteristics. An operator must establish a schedule for evaluating, and remediating, as necessary, the similar pipeline segments that is consistent with the operator's established operating and maintenance procedures under this part for testing and repair.

30. In § 192.921, revise paragraph (a) and add paragraph (i) 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).

(1) Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible. The use of internal inspection tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (*e.g.*, 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. In addition, an operator must analyze and account for uncertainties in reported results (*e.g.*, 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. The use of subpart J pressure testing is appropriate for threats such as internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7) to justify an extended reassessment interval in accordance with § 192.939.

(3) Spike hydrostatic pressure test conducted in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for time-dependent 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. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion,

internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and the pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. 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 and 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 must notify PHMSA in advance of using the other technology in accordance with § 192.18.

* * * * *

(i) *Baseline assessments for pipeline segments with a reconfirmed MAOP.* An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a baseline assessment under this section.

31. In § 192.933, paragraphs (a)(1) and (2) are revised 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); R-STRENG (incorporated by reference, *see* §192.7); or by reducing the operating pressure to a level not

exceeding 80 percent of the level at the time the condition was discovered. An operator must notify PHMSA in accordance with §192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action.

(2) *Long-term pressure reduction*. When a pressure reduction exceeds 365 days, an operator must notify PHMSA under § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

*   *   *   *   *

32. In § 192.935, paragraph (b)(2) is revised to read as follows:

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

*   *   *   *   *

(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 increasing the frequency of aerial, foot or other methods of patrols; adding external protection; reducing external stress; relocating the line; or inline inspections with geospatial and deformation tools.

*   *   *   *   *

33. In § 192.937, revise paragraph (c) and add paragraph (d) to read as follows:

§ 192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

* * * * *

(c) *Assessment methods.* In conducting the integrity reassessment, 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 on the covered segment (*see* § 192.917).

(1) *Internal inspection tools.* When performing an assessment using an in-line inspection tool, an operator must comply with the following requirements:

(i) Perform the in-line inspection in accordance with § 192.493;

(ii) Select a tool or combination of tools capable of detecting the threats to which the pipeline segment is susceptible such as corrosion, deformation and mechanical damage (*e.g.* dents, gouges and grooves), material cracking and crack-like defects (*e.g.* 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; and

(iii) Analyze and account for uncertainties in reported results (*e.g.*, 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*. The use of pressure testing is appropriate for threats such as: internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7) to justify an extended reassessment interval in accordance with § 192.939.

(3) *Spike hydrostatic pressure test in accordance with § 192.506*. The use of spike hydrostatic pressure testing is appropriate for time-dependent 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. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, or magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. 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, and 192.929;

(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 must notify PHMSA in advance of using the other technology in accordance with § 192.18; or

(8) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than 7 calendar years. An operator using this reassessment method must comply with § 192.931.

(d) *MAOP reconfirmation assessments*. An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a reassessment under this section.

34. In § 192.939, paragraphs (a) introductory text, (b) introductory text, and (b)(1) are 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 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS, in accordance with § 192.18, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than 7 calendar years, the operator must, within the 7-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.

*   *   *   *   *

(b) *Pipelines Operating below 30% SMYS*. An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS in accordance with § 192.18. The notice must include sufficient justification of the need for the extension. An operator must establish reassessment by at least one of the following –

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than 7 calendar years, an operator must conduct by the seventh calendar year of the interval either a confirmatory direct assessment in accordance with § 192.931, or a low stress reassessment in accordance with § 192.941.

*   *   *   *   *

§ 192.949 [Removed and Reserved]

35. Remove and reserve § 192.949.

36. Appendix F 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 90 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 carrier pipe.

I. *Equipment and Software: Generation.* The equipment and the computer software used are critical to the success of the inspection. Computer software for the inspection equipment must be reviewed and updated, as required, on an annual basis, with intervals not to exceed 15 months, to support sensors, enhance functionality, and resolve any technical or operational issues identified.

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.* 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).

The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented.

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.* 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. 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.* 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. 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 pipe, then another type of assessment method must be utilized.

XI. *End Seal.* When assessing cased carrier pipe with GWUT, 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 pipeline 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 pipeline 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 a documented engineering analysis and evaluation.

XIII. *Validation of Operator Training*. 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:

A. equipment operation,

B. field data collection, and

C. data interpretation on cased and buried pipe.

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. 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 training specific to cased and buried pipe, with a quality control program which that conforms to Section 12 of ASME B31.8S (for availability, see § 192.7).

XIV. *Training and Experience Minimums for Senior Level GWUT Equipment Operators*:

• Equipment Manufacturer’s minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe

• Training, qualification and experience in testing procedures and frequency determination

• 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)

• Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XV. *Equipment: traceable from vendor to inspection company.* An 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.

XVI. *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 to a different casing or pipeline segment. 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.

XVII. *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.

XVIII. *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 or other GWUT application. If this cannot be accomplished, then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

XIV. *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.

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Howard R. Elliott,

Administrator.

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