July 7, 2016

Via www.regulations.gov and email

Marie Therese Dominguez
Administrator
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
1200 New Jersey Avenue, S.E.
Washington, DC 20590-0001

Re: Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines (Docket ID: PHMSA-2011-0023)

Dear Administrator Dominguez:

The Interstate Natural Gas Association of America (INGAA), a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry in North America, respectfully submits these comments in response to the "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines" Notice of Proposed Rulemaking (NPRM). INGAA will file certain attachments under separate cover.

INGAA appreciates your consideration of these comments.

Sincerely,

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UNITED STATES OF AMERICA
BEFORE THE
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Safety of Gas Transmission	**§**	
and Gathering Pipelines	**§**	**Docket No. PHMSA-2011-0023**
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COMMENTS OF
THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

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Comments of
The Interstate Natural Gas Association of America

I. Introduction

The Interstate Natural Gas Association of America (INGAA) offers these comments on the Notice of Proposed Rulemaking (NPRM) issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) on April 8, 2016.[1]

INGAA is a trade association representing approximately two-thirds of the nation's natural gas transmission pipeline systems. INGAA's 24 members operate approximately 200,000 miles of interstate gas transmission pipelines.

Pipeline safety is the top priority of INGAA and its members. INGAA strongly supports regulations that embrace and advance improvements in pipeline safety practices, with the intent of achieving the goal of zero incidents. For the last 15 years, INGAA members have achieved significant advances in safety through implementation of PHMSA's integrity management regulations in Subpart O of Part 192. INGAA supports the process of risk and threat identification, prioritization, data integration, prevention and mitigation, with the foundation of continuous improvement.

Based on its commitment to safety, INGAA advanced its Integrity Management Continuous Improvement (IMCI) initiative in 2011. The scope of this voluntary initiative is broad, extending the protections of integrity management practices beyond High Consequence Areas (HCAs) to all people living, working and recreating near an interstate natural gas transmission pipeline. INGAA has engaged with many stakeholders, including PHMSA, state regulators, the National Transportation Safety Board (NTSB), and various public advocacy groups (including the Pipeline Safety Trust) to develop specific programs to advance IMCI commitments. The lessons learned from operators' experiences are significant. In considering additional regulatory initiatives, PHMSA should consider and apply the lessons learned from INGAA's experience.

[1] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722 (Apr. 8, 2016) (NPRM).

INGAA has identified key provisions in the NPRM that PHMSA should modify to improve pipeline safety. In several instances, the NPRM requirements will have unintended consequences that actually hinder the continued advancement of pipeline safety practices. They also will increase safety risks and adverse environmental impacts, discourage the implementation of advanced technologies, and adversely affect the reliability of the national natural gas pipeline grid. INGAA offers alternative approaches and regulatory language that would more effectively promote safe pipeline practices and meet the goals of the NPRM without compromising the reliable delivery of natural gas.

Given the complexity of the NPRM, INGAA urges PHMSA to convene a public workshop to permit stakeholders and interested entities to identify and discuss their concerns and possible alternatives to the NPRM. If PHMSA does not convene a workshop, then INGAA is willing to work with the PHMSA and other trade associations, state regulators and public representatives to provide an open public forum to discuss comments filed by stakeholders to the NPRM.

II. Executive Summary

Pipelines are the safest and most efficient way to transport natural gas. INGAA is committed to the continued safe and reliable operation of the nation's gas transmission pipeline infrastructure, and INGAA fully supports PHMSA's goal of ensuring that pipeline operations remain safe and reliable. INGAA's goal of zero incidents and a nine-point action plan are key elements of INGAA's IMCI initiative.

A. Building on IMCI

Since 2011, INGAA members have proactively developed and implemented practices and processes designed to improve pipeline integrity, including taking steps to implement integrity management principles on a system-wide basis. INGAA and its members have worked to improve assessment technologies, remediation approaches, and preventive and mitigative activities. Through the industry's efforts, operators have improved knowledge of pipeline systems and how to best mitigate the risks that threaten pipeline safety. These efforts are consistent with PHMSA's intended direction. Based on these initiatives, INGAA has gained the experience necessary to propose improvements to the NPRM that will continue to move the industry forward and advance pipeline safety.

B. Overview of INGAA's Comments and Key Areas of the NPRM

The NPRM reflects an overly complicated and rigid approach to pipeline safety that threatens to slow the industry's progress toward achieving shared safety goals and improving safety technologies. Under the NPRM, operators would be required to allocate significant resources to activities that do little, if anything, to increase the margin of safety. PHMSA's proposal should ensure that required activities, resource allocations, and investments are targeted at value-added measures that improve pipeline safety. INGAA's comments offer alternatives that will achieve the same, if not better, pipeline safety improvements with less disruption to reliable natural gas service, less impact to the environment, and less cost to pipeline ratepayers and consumers.

Several key areas of the NPRM need modification because, as proposed, they will have significant unintended consequences:

1. Emphasizing hydrostatic pressure tests for MAOP reconfirmation (which provide limited information) constrains the development and implementation of advanced alternative technologies, such as ILI, that have the ability to provide more information about the pipeline and improve pipeline safety.
2. Requiring spike hydrostatic pressure testing as a requirement for establishing maximum allowable operating pressure (MAOP) for legacy pipe when no technical basis for doing so exists. This requirement will significantly harm the environment

and disrupt market reliability without providing any incremental pipeline safety improvement.

3. Requiring overly prescriptive material verification will result in increased risk, unnecessary service disruptions, and add excessive costs to collect data that does not improve pipeline safety.

PHMSA should modify these three key NPRM proposals, as well as a number of other issues, to ensure that the PHMSA rulemaking effectively enhances pipeline safety. INGAA, in these comments, will detail further its concerns and make recommendations to improve these three key areas:

1. Emphasizing Hydrostatic Pressure Tests for MAOP Reconfirmation (Which Provide Limited Information) Constrains the Development and Implementation of Advanced Alternative Technologies, such as ILI, That Have the Ability to Provide More Information About the Pipeline and Improve Pipeline Safety.

The pipeline industry, its service providers, and its state and federal regulators have a proven record of developing and implementing continuous improvements to pipeline safety through the promotion and adoption of new technologies and improved safety practices. The evolution of in-line inspection (ILI), aboveground survey, remote sensing, engineering critical assessment (ECA), and many other advances have dramatically improved the safety and reliability of pipelines. These advances, as well as promising new developments, have far greater potential to improve pipeline safety while having far fewer negative consequences than older, blunt techniques such as hydrostatic pressure testing.

Hydrostatic pressure testing is one of the oldest pipeline testing technologies. It is employed primarily to establish the MAOP (material strength) of a pipeline by demonstrating its one-time ability to withstand a pressure at some level above the intended operating pressure. Hydrostatic pressure testing provides no additional information regarding the condition of the pipeline, nor can it inform operators how the pipe will perform during its ongoing service. Advances in technology have provided alternatives that are not only significantly better than hydrostatic pressure testing for establishing a pipe's material strength, but also can provide critical information about the overall condition of the pipeline. This information, such as the identification of sub-critical flaws that would survive a hydrostatic pressure test, can be used to develop enhanced strategies for monitoring, maintaining, and improving the safety of the pipeline throughout its service life.

Hydrostatic pressure testing has significant disadvantages that the NPRM fails to consider. Hydrostatic pressure testing requires disrupting natural gas service to the market, venting methane to the atmosphere, excavations, construction activities, and service outages to pipeline customers. Hydrostatic pressure testing uses water, resulting in environmental impacts and costs from the displacement of significant volumes of fresh stream and lake water and the disposal of used water. If, rather than hydrostatically pressure test, operators can utilize ILI to reconfirm MAOP, market, service, and environmental impacts can be reduced.

The NPRM introduces complex and prescriptive requirements for allowing the use of alternatives to hydrostatic pressure testing. These requirements would be so onerous and unpredictable in their application that operators will never realize the full benefits of alternative technologies, including improving the understanding of the pipeline. The ongoing evolution of pipeline safety practices will be limited, and the increasing use of hydrostatic pressure testing will negatively impact the environment, provide less pipeline safety value, and increase cost and risk. As detailed in Section VII of these Comments, INGAA proposes to allow the use of alternative methods for validating MAOP in order to ensure the ongoing development and implementation of technologies and practices that improve pipeline safety.

2. Requiring Spike Hydrostatic Pressure Testing For Establishing MAOP for Legacy Pipe Has No Technical Basis, And Will Significantly Harm the Environment and Disrupt Market Reliability Without Providing Any Incremental Pipeline Safety Improvement.

Spike hydrostatic pressure testing was developed for the targeted management of stress corrosion cracking (SCC) on pipelines. It was designed as an integrity assessment technique for exposing significant time-dependent linear defects. SCC has been identified as the only significant time-dependent, linear defect threat on gas pipelines. The NPRM proposes to require spike hydrostatic testing to confirm the MAOP of legacy pipelines, even though Subpart J pressure testing, and not spike hydrostatic pressure testing, is the long-standing method for establishing or reconfirming MAOP.

Spike testing is not an appropriate technique for MAOP reconfirmation, and will result in unintended negative consequences without improving pipeline safety. Spike testing is an aggressive and destructive test that should be used only where time-dependent threats, such as a significant risk of SCC, exists. Spike testing yields no added benefits from an MAOP establishment perspective, yet it imparts significant stresses on the pipeline, its components, and the testing equipment. These stresses introduce the risk of failures of piping and components that would otherwise pose no threat during the service life of the pipeline. Such failures would require repairs and cause other adverse effects, such as further customer service disruptions and increased methane emissions.

INGAA supports reconfirming the MAOP of previously untested pipelines and those lacking pressure test records in HCAs, Class 3, Class 4 and MCAs operating at greater than 30% of SMYS. PHMSA's existing regulations and industry consensus standards support the proposition that hydrostatic pressure testing under Subpart J establishes a conservative and proven margin of safety between the test level and the MAOP. The benefits and sufficiency of

Subpart J pressure testing at this level for purposes of establishing material strength are well documented in technical literature. Features present from original manufacturing and historical construction techniques are "resident" and do not grow in service unless acted upon by another threat such as external corrosion, outside force, or pressure cycling. Ongoing operations, maintenance, and integrity programs pursuant to PHMSA's existing Subpart O regulations manage each of these threats, including their interaction with a resident feature.

A single Subpart J pressure test, or testing to Subpart J pressure test levels, is a conservative and proven method to establish MAOP. This reasonable safety margin serves as the starting point for managing a pipeline's integrity. An operator then uses ongoing operation, maintenance, and integrity management activities to manage the condition of the pipeline continually. If its condition deteriorates, a pipeline is evaluated using proven testing methods to ensure safe continued operation, or it is repaired or replaced to restore the conservative safety margin. PHMSA should withdraw the proposal for spike hydrostatic pressure testing for the confirmation of MAOP.

3. Requiring Overly Prescriptive Material Verification Will Result in Increased Risk, Unnecessary Service Disruptions, and Add Excessive Costs to Collect Data That Does Not Improve Pipeline Safety.

While INGAA supports improving pipeline data in HCAs, PHMSA should focus on data that contributes to maintaining and improving pipeline safety. In § 192.607, the NPRM proposes to require that operators prepare a material documentation plan and conduct verification of material properties through a mixture of destructive and non-destructive tests whenever a pipe segment is exposed.

The following five data elements proposed in the NPRM are not required for maintaining pipeline integrity and are impractical to obtain: "ultimate tensile strength," "chemical composition," "manufacturing specifications," "toughness using a Charpy v-notch test," and "weld end bevel condition." These data elements are not used in integrity management processes, and can be obtained only through the destructive testing of a pipeline. This requirement will lead to unnecessary outages, increased methane emissions, increased personnel safety risk due to unnecessary construction activities, and significant added costs for which there is no pipeline safety benefit. PHMSA should remove these overly prescriptive material verification criteria from the NPRM.

C. The NPRM Presents Other Significant Concerns.

The NPRM fails to recognize the cumulative impact of the individual proposed regulations. The individual provisions of the NPRM cannot be viewed in isolation. Provisions that would appear to be limited to specific situations and types of pipelines in fact apply far more broadly due to numerous cross references. As a result, some of the proposal's most burdensome provisions apply to almost all portions of transmission pipelines. For example, the language of proposed § 192.607, requiring the verification of pipeline material, is limited to gas transmission pipelines located in HCAs and Class 3 or 4 locations that lack "reliable, traceable, verifiable, and complete" records. Several other unrelated provisions, however, cross reference § 192.607, meaning that this section applies far more broadly than the text of the regulation would suggest. The NPRM does not acknowledge the actual reach of the proposed regulations, the cost associated with this, or the cumulative impact.

The NPRM does not recognize the proposal's implications for compliance with other applicable federal requirements, including those of the Environmental Protection Agency (EPA) and the Federal Energy Regulatory Commission (FERC). The increased methane emissions associated with hydrostatic pressure testing and certain repairs will run counter to the President's goals of reducing methane emissions, as reflected by the new EPA rule restricting methane emissions from certain oil and gas facilities. Removing lines from service in order to perform hydrostatic pressure testing will raise issues under the regulations and policies of FERC under the Natural Gas Act (NGA). FERC policies, which are premised on an interstate pipeline's obligation to serve, require a pipeline to receive FERC's permission to perform certain pipeline replacements or to remove lines from service permanently. These rules could inhibit a pipeline from taking actions quickly or limit a pipeline's ability to abandon lines that no longer can be operated safely and economically. In addition, the Preliminary Regulatory Impact Assessment (PRIA) fails to recognize that FERC requires interstate natural gas pipelines to provide demand charge credits to customers when firm transportation services are disrupted. This includes when the disruption is caused by testing and repairs.

The NPRM does not comply with the requirements of the Administrative Procedure Act (APA), the Pipeline Safety Laws, the National Environmental Policy Act (NEPA), Paperwork Reduction Act (PRA), or the Council on Environmental Quality (CEQ) guidelines. For example, the NPRM preamble lacks any engineering analysis or justification for many of the proposed provisions. Passing references to recent pipeline accidents or to NTSB recommendations do not constitute sufficient evidentiary support for the proposition that a broad-based problem exists or that the proposed regulatory directive is the appropriate solution to the identified problem.

The NPRM is inconsistent with the Pipeline Safety Act (PSA). The NPRM does not reflect consideration of the factors the PSA requires be considered when PHMSA adopts new safety standards. The NPRM also violates the prohibition on applying certain regulatory requirements retroactively on pipelines, misapplies the requirements of the Pipeline Safety Regulatory Certainty, and Job Creation Act of 2011 (2011 Act), and contains no record evidence that PHMSA complied with the statutory requirement to consult with FERC and state regulators on implementing strength testing timelines. In addition, the cost-benefit analysis contained in PHMSA's PRIA falls far short of the PSA's requirements to perform a risk-based cost-benefit analysis. The PRIA is grossly inaccurate because it significantly underestimates the costs of certain proposed rules and significantly overestimates the NPRM's benefits. In addition, the

NPRM’s Draft Environmental Assessment falls well short of meeting NEPA requirements and CEQ guidance.

INGAA is committed to pipeline safety and accepts the challenge of continuously improving pipeline integrity and safe operations. INGAA requests that PHMSA promote this effort by promulgating regulations that enable, rather than frustrate, operators’ ability to implement the most effective technologies and approaches for promoting the safe and reliable operation of the nation’s gas pipeline infrastructure.

III. Statutory Framework

Under the APA, the lawfulness of the PHMSA's final rule and the resulting new pipeline safety standards is determined based on whether the final rule is "arbitrary or capricious, an abuse of discretion, or otherwise not in accordance with law."[2] This determination is informed by whether PHMSA's final rule reflects reasoned decision-making under APA principles, as well as whether PHMSA complies with the requirements of the other statutes like the PSA,[3] the NEPA[4], and the PRA.[5] The following framework provides an overview of the applicable governing principles.

When issuing a final rule, PHMSA is required to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'"[6] PHMSA's explanation for its decision "may not be superficial or perfunctory"[7] and must be consistent with the evidence.[8] A final rule is arbitrary and capricious if the agency relies "on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise."[9] In addition, PHMSA must reveal and provide the technical bases for its proposed rules and allow adequate time "for meaningful commentary" or be found in violation of the notice and comment provisions of section 553(c) of the APA.[10] A final rule that does not comply with these principles is arbitrary and capricious.

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[2] 5 U.S.C. §§ 706(A) (2012).

[3] 49 U.S.C. §§ 60101-60140 (2012 & Supp. II 2014).

[4] 42 U.S.C. §§ 4321-4347 (2012).

[5] 44 U.S.C. §§ 3501-3520 (2012 & Supp. II 2014).

[6] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines v. United States*, 371 U.S. 156, 168 (1962)) (vacating as arbitrary and capricious final rule that rescinded regulations without adequate explanation).

[7] *Owner-Operator Indep. Drivers Ass'n v. FMCSA*, 656 F.3d 580, 588 (7th Cir. 2011) (applying *State Farm* standard and vacating final rule as arbitrary and capricious).

[8] *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 839, 843 (D.C. Cir. 2006) (vacating agency rule because record evidence did not support existence of the problem the rule purported to address).

[9] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (vacating agency's rescission of regulation without adequate explanation); *Pub. Citizen v. FMCSA*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) (finding that agency's failure to consider statutory factor constituted a failure to consider an important aspect of the problem).

[10] *Owner-Operator Indep. Drivers Ass'n* v. *FMCSA*, 494 F.3d 188, 199 (D.C. Cir. 2007) (citing *Solite Corp. v. EPA*, 952 F.2d 473, 484 (D.C. Cir. 1991)) (finding that agency's failure to disclose the methodology of the agency's operator-fatigue model for performing a crash-risk analysis when that model was the basis for the cost-benefit

Failure to comply with the requirements of the PSA also is arbitrary and capricious. Under the PSA, PHMSA is charged with protecting against risks posed by pipelines by prescribing minimum safety standards for pipeline transportation and pipeline facilities.[11] PHMSA's authority to issue safety standards is constrained by the PSA's requirements and proscriptions. The PSA requires that a safety standard be "practicable" and designed to meet gas pipeline safety needs *and* protect the environment.[12] When prescribing any safety standard, PHMSA is required to consider relevant available gas pipeline safety information, environmental information, the appropriateness of the standard for the type of transportation or facility, reasonableness, comments and information received from the public, and comments and recommendations of the Technical Pipeline Safety Standards Committee.[13]

The PSA requires that PHMSA consider, "based on a risk assessment, the reasonably identifiable or estimated costs expected to result from" implementing or complying with the standard.[14] When performing this risk assessment, PHMSA must, *for each standard*,

> (A) identify the regulatory and nonregulatory options that the Secretary considered in prescribing a proposed standard;
> (B) identify the costs and benefits associated with the proposed standard;
> (C) include –
> (i) an explanation of the reasons for the selection of the proposed standard in lieu of the other options identified; and
> (ii) with respect to each of those other options, a brief explanation of the reasons that [PHMSA] did not select the option; and
> (D) identify technical data or other information upon which the risk assessment information and proposed standard is based.[15]

Disregarding the PSA's statutorily-mandated factors when adopting a safety standard is arbitrary and capricious[16] and reflects a failure to consider an important aspect of the problem, in

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analysis used in the agency's Regulatory Impact Assessment violated APA's notice and comment requirements).

[11] 49 U.S.C. § 60102(a)(1) & (2).

[12] 49 U.S.C. § 60102(b)(1).

[13] 49 U.S.C. § 60102(b)(2).

[14] 49 U.S.C. § 60102(b)(2).

[15] 49 U.S.C. § 60102(b)(3).

[16] *Owner-Operator Indep. Drivers Ass'n v. FMCSA*, 656 F.3d 580, 589 (7th Cir. 2011) (vacating rule because agency failed to consider an issue it was statutorily required to address); *Pub. Citizen v. FMCSA*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) (vacating final rule for failing to consider impact of final rule on the health of drivers, a mandatory statutory consideration under organic statute). *Id.* (stating that "'the complete absence of any discussion' of a statutorily mandated factor 'leaves us with no alternative but to conclude that [the agency] failed to take account of the statutory limit on [its] authority,'" making the agency's reasoning arbitrary and capricious.") (citing *United Mine Workers v. Dole*, 870 F.2d 662, 673 (D.C. Cir. 1989)).

violation of the APA.[17] Moreover, these factors apply to each proposed safety standard, as evidenced by use of the singular noun "standard" throughout these provisions.[18]

The issuance of safety standards to address records and MAOP reconfirmation and material strength testing are subject to additional requirements under the PSA. Section 60139 of the statute requires that PHMSA issue regulations providing for the material strength testing of previously untested natural gas transmission pipelines that are located in HCAs and that operate at a pressure producing a hoop stress greater than 30% of specified minimum yield strength (SMYS).[19] PHMSA is required to consult with the Chairman of FERC and state regulators to establish timelines to complete such testing that consider potential public safety and environmental consequences and that minimize costs and service disruptions.[20] Disregarding this statutory directive of the PSA would be arbitrary and capricious because it constitutes a failure "to consider an important aspect of the problem" and to consider a statutory requirement.[21]

For transmission owners or operators with pipelines in Class 3 or Class 4 locations or Class 1 and Class 2 HCAs that lack records to verify MAOP, Section 60139 of the PSA directs PHMSA to require those owners or operators reconfirm MAOP as "expeditiously as economically feasible."[22] PHMSA is further directed to determine the appropriate actions to be taken to maintain safety until MAOP can be confirmed. In doing so, PHMSA is required to consider potential consequences to public safety *and* the environment, potential impacts on pipeline system reliability and deliverability, and other factors. Issuing regulations directing operators to take actions without considering these factors is arbitrary and capricious.[23]

In addition to specifying factors PHMSA must consider when adopting a safety standard, the PSA constrains PHMSA's authority to issue safety regulations. Section 60104(b) prohibits PHMSA from applying new safety standards pertaining to design, installation, construction,

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[17] *Pub. Citizen v. FMCSA*, 374 F.3d 1209, 1216 (D.C. Cir. 2004).

[18] *C.f., Am. Fed'n of Labor and Cong. of Indus. Orgs. v. OSHA*, 965 F.2d 962, 969 (11th Cir. 1992) (finding that, where statute required agency to establish permanent exposure limits (PEL) for air contaminants in the workplace based on substantial evidence of the risk the contaminants posed to workers, agency was required to demonstrate that the PEL for each contaminant was supported, and that failure to make such demonstration was arbitrary and capricious).

[19] 49 U.S.C. § 60139(d)(1).

[20] 49 U.S.C. § 60139(d)(3).

[21] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); *Pub. Citizen v. FMCSA*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) (finding that agency's failure to consider statutory factor constituted a failure to consider an important aspect of the problem).

[22] 49 U.S.C. § 60139(c)(1)(A).

[23] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983), *Pub. Citizen v. FMCSA*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) (finding that agency's failure to consider statutory factor constituted a failure to consider an important aspect of the problem).

initial inspection and initial testing to pipeline facilities already existing when the standard is adopted.[24] To the extent that the final rule would require existing pipelines to comply with new design, installation, construction, initial inspection and initial testing requirements, the final rule would violate the PSA and is arbitrary and capricious.

Under NEPA[25] and the PSA,[26] the final rule also must reflect meaningful consideration of the environmental impacts of the proposed safety standards.[27] NEPA requires that before issuing a final rule adopting the proposed safety standards, PHMSA is required to assess whether the proposal constitutes a major federal action that will significantly affect the quality of the human environment.[28] If the proposed rule will have a "significant impact," PHMSA must prepare an environmental impact statement (EIS), which provides a detailed and comprehensive analysis of the potential environmental impacts of the proposed action and must include an analysis of alternatives to the proposed action.[29] PHMSA can prepare an environmental assessment, which "[b]riefly provides sufficient evidence and analysis for determining whether" the proposed action warrants an EIS.[30] If, based upon the environmental assessment, PHMSA determines that the proposed action does not significantly affect the environment, it will issue a finding of no significant impact explaining its reasoning; otherwise, an EIS is required.[31]

PHMSA must take a "hard look" at information relevant to its decision, which requires "sufficient discussion of the relevant issues and opposing viewpoints" and that the decision be "fully informed" and "well-considered."[32] Under the CEQ regulations, PHMSA must "[i]dentify environmental effects and values in adequate detail so they can be compared to economic and technical analyses," and "[s]tudy, develop, and describe appropriate alternatives to recommended courses of action."[33] While more concise than an EIS, an environmental assessment must include, in part, "discussions of the need for the proposal, of alternatives [to the proposed

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[24] 49 U.S.C. § 60104(b).

[25] 42 U.S.C. §§ 4321-47.

[26] 49 U.S.C. § 60102(b)(2)(A)(iii).

[27] *Wyo. v. U.S. Dep't of Agric.*, 661 F.3d 1209, 1236-37 (10th Cir. 2011) (stating that NEPA requires that an agency "consider every significant aspect of the environmental impact of a proposed action" and "ensures that the agency will inform the public that it has indeed considered environmental concerns in its decisionmaking process") (quoting *Forest Guardians v. U.S. Fish & Wildlife Service*, 611 F.3d 692, 711 (10th Cir. 2010).

[28] 42 U.S.C. § 4332(2)

[29] 42 U.S.C. §§ 4332(2)(C) & (E).

[30] 40 C.F.R. § 1508.9. It is not necessary to prepare an EA if the agency decides to proceed directly to preparing an EIS. 40 C.F.R. § 1501.3(a).

[31] 40 C.F.R. §§ 1501.4, 1508.13.

[32] *Myersville Citizens for a Rural Cmty. v. FERC*, 783 F.3d 1301, 1324-25 (D.C. Cir. 2015) (quoting *Nevada v. Dep't of Energy*, 457 F.3d 78, 93 (D.C. Cir. 2006) (internal quotations omitted)).

[33] 40 C.F.R. § 1501.2 (b) & (c).

action], [and] of the environmental impacts of the proposed action and alternatives."[34] PHMSA is also required to include consideration of "connected actions," "cumulative actions," and "similar actions" in an environmental assessment.[35] Finally, recent CEQ draft guidance emphasizes the importance of an agency giving informed consideration of the effects of greenhouse gas (GHG) emissions and climate change when evaluating a proposed federal action.[36] Thus, when issuing a final rule adopting new safety standards, PHMSA is required by both NEPA and the PSA to identify and fully evaluate all of the environmental impacts of the proposed safety standards.

In performing its environmental assessment of the impacts of the proposed safety standards, PHMSA also must acknowledge the comprehensive environmental impacts of its proposed safety standards when they are taken together as a whole. In particular, PHMSA must acknowledge that the NPRM is replete with cross references that effectively impose some of the most environmentally significant proposals (such as hydrostatic pressure testing requirements) on a broader range of pipelines than the language of each isolated provision would suggest. PHMSA must analyze the comprehensive environmental impacts of these requirements, such as GHG emissions, water resource impacts, and disturbance to wildlife mating and habitat.[37]

NTSB safety recommendations do not modify statutory requirements or excuse PHMSA from the requirements and limitations of the PSA and NEPA. Under the National Transportation Safety Board Act, the NTSB investigates certain transportation accidents; determines their probable cause; and, based on its findings, issues safety recommendations specific to the investigated accident to affected stakeholders, including federal regulators like PHMSA. PHMSA must formally respond to the NTSB's recommendations,[38] but is not required to adopt them. The NTSB has issued a number of safety recommendations to PHMSA in response to several recent pipeline accidents.[39] Consistent with its safety mission, the NTSB's recommendations are focused on promoting transportation safety and address the specific

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[34] 40 C.F.R. § 1508.9(b).

[35] *Myersville Citizens for a Rural Cmty.* 783 F.3d 1301, 1326 (citing 40 C.F.R. § 1508.25(a)(1)-(3)).

[36] Revised Draft Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in NEPA Reviews, 79 Fed. Reg. 77,802 (Dec. 24, 2014).

[37] *See infra* Section XVII below.

[38] 49 U.S.C. § 1135(a).

[39] NTSB, Pipeline Accident Report, Pacific Gas and Electric Co., Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, Sept. 9, 2010 at 128-34, NTSB/PAR-11/01, PB2011-916501 (Aug. 30, 2011), http://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1101.pdf; NTSB, Pipeline Accident Report, Enbridge Inc., Hazardous Liquid Pipeline Rupture and Release, Marshall, Michigan, July 25, 2010 at 122-25, NTSB/PAR-12/01, PB2012-916501 (July 10, 2012) , http://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1201.pdf; NTSB, Pipeline Accident Report, Columbia Gas Transmission Corp. Pipeline Rupture, Sissonville, West Virginia, Dec. 11, 2012 at 35 NTSB/PAR-14/01, PB2014-103977 (Feb. 19, 2014) , http://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1401.pdf..

incident at issue. The NTSB does not, however, consider technological or economic feasibility, environmental impacts, service reliability issues, or the requirements and limitations of other governing statutes, like the PSA and NEPA. PHMSA has the responsibility to consider statutorily-mandated factors and environmental issues when adopting safety standards intended to implement NTSB recommendations broadly to the entire industry, rather than on a case-by-case, fact-specific basis.[40] This responsibility includes assessing whether an NTSB recommendation may result in any unintended adverse safety or environmental consequences.

PHMSA also must comply with the PRA, which prohibits federal agencies from requesting information from the public without obtaining prior approval from the Office of Management and Budget (OMB) by submitting an information collection request (ICR). The administrator of the Office of Information and Regulatory Affairs (OIRA), which exercises authority delegated from OMB to approve an agency's ICR, must determine whether PHMSA's proposed ICR "is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility."[41] PHMSA may not collect the information if the Administrator determines that the information is unnecessary.[42]

Before submitting an ICR, the PRA requires that PHMSA conduct a review of the proposed information collection that includes:

i. An evaluation of the need for the collection of information;
ii. A functional description of the information to be collected;
iii. A plan for the collection of the information;
iv. A specific, objectively supported estimate of burden;
v. A test of the collection of information through a pilot program, if appropriate; and
vi. A plan for the efficient and effective management and use of the information to be collected, including necessary resources.[43]

OMB's regulations require that PHMSA demonstrate that the proposed ICR:

i. Is the least burdensome necessary for the proper performance of the agency's functions to comply with legal requirements and achieve program objectives;
ii. Is not duplicative of information otherwise accessible to the agency; and
iii. Has practical utility.

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[40] *C.f., Am. Fed'n of Labor and Cong. of Indus. Orgs. v. OSHA*, 965 F.2d 962, 984 (11th Cir. 1992) (finding that use of expert consultants does not relieve agency of the responsibility for making detailed findings, with adequate explanation, for all statutory criteria because the recommendations are not always based on the criteria required by the statute).

[41] 44 U.S.C. § 3508.

[42] 44 U.S.C. § 3508.

[43] 44 U.S.C. § 3506(c)(1)(A).

The agency must also seek to minimize the cost to itself of collecting, processing, and using the information, but must not do so by means of shifting disproportionate costs or burdens onto the public.[44]

Even if the information is required by statute, PHMSA's ICR must satisfy these criteria and demonstrate that the burden of the proposed ICR is justified by its practical utility.[45] Compliance with the PRA is not required only if a specific information collection is mandated by statute or originates with Congress.[46]

[44] 5 C.F.R. § 1320.5(d).

[45] 5 C.F.R. § 1320.5(d). "OMB will consider necessary any collection of information specifically mandated by statute or court order, but will independently assess any collection of information to the extent that the agency exercises discretion in its implementation." 5 C.F.R. § 1320.5(e). This approach is consistent with the PRA's legislative history. *See* S. Rep. No. 96-930, at 49 (1980) ("The fact the collection of information is specifically required by statute does not, however, relieve an agency of the obligation to submit the proposed collection for the Director's review.").

[46] *United States v. Ionia Mgmt. S.A.*, 498 F.Supp.2d 477 (D. Conn. 2007) (PRA did not apply because the duty to maintain oil record book originated in treaty and was incorporated into the statute by Congress and specified the information to be retained); *Gossner Foods, Inc. v. EPA*, 918 F. Supp. 359 (D. Utah 1996) (Where the Emergency Planning and Right-to-Know Act specified information to be submitted in a "Toxic Chemicals Release Form," the PRA did not apply).

IV. Procedural Context

PHMSA's NPRM represents a significant milestone in the almost 5-year rulemaking process that began with an Advanced Notice of Proposed Rulemaking (ANPRM) issued in August 2011 and continued in 2013 when PHMSA initiated the development of the Integrity Verification Process (IVP) following passage of the 2011 Act. Although the ANPRM and IVP proceedings have different docket numbers, PHMSA has effectively consolidated them in this NPRM and, as such, they should be considered as a single proceeding.

PHMSA issued the ANPRM to initiate consideration of potential modifications to the regulations applicable to gas transmission pipelines.[47] The ANPRM requested comments on 15 topics and numerous subtopics, many of which are addressed in the NPRM. Shortly after PHMSA issued the ANPRM, Congress enacted the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Act)[48] containing several directives relevant to the issues under consideration in this proceeding.

Section 23 of the 2011 Act requires, among other things, that PHMSA direct operators to verify (pursuant to elements determined by PHMSA) that records for certain gas transmission pipe confirm the line's established MAOP and accurately reflect the line's physical and operational characteristics.[49] For pipeline segments lacking records sufficient to confirm established MAOP, PHMSA was directed to (1) require that MAOP be confirmed as expeditiously and economically feasible; and (2) determine appropriate interim actions. Section 23 of the 2011 Act also required that PHMSA issue regulations for conducting material strength tests of previously untested gas transmission lines that are located in HCAs and operate at pressures producing hoop stress of more than 30% SMYS.

Following passage of the 2011 Act, PHMSA expanded its examination of regulations affecting gas transmission pipelines by unveiling an IVP in August 2013.[50] IVP principles were intended to implement the directives of the new statute, as well as safety recommendations issued by the NTSB following the pipeline rupture in San Bruno, California.[51] Although IVP was initiated as a proceeding separate from the then-pending ANPRM, PHMSA has effectively

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[47] Pipeline Safety: Safety of Gas Transmission Pipelines, Advanced Notice of Proposed Rulemaking, 76 Fed. Reg. 53,086 (Aug. 25, 2011).

[48] Pub. L. No. 112-90, 125 Stat. 1904 (2012) (codified at §§ 60101 - 60140).

[49] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 § 23, 125 Stat. at 1918 (codified at 49 U.S.C. § 60139).

[50] Pipeline Safety: Public Workshop on Integrity Verification Process, 78 Fed. Reg. 32,010 (May 28, 2013).

[51] Pipeline Safety: Public Workshop on Integrity Verification Process, 78 Fed. Reg. 32,010 (May 28, 2013). Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722, 20,736 (Apr. 8, 2016).

consolidated the two dockets in this NPRM, as IVP principles are reflected in a number of the NPRM's proposed provisions.[52]

[52] NPRM at 20,736.

V. Moderate Consequence Areas

A. PHMSA Should Modify the Proposed Definition of Moderate Consequence Areas.

INGAA supports the addition of a moderate consequence area (MCA) category, but PHMSA should make certain modifications to its definition of an MCA, including limiting these areas to segments that can accommodate "instrumented inline inspection." INGAA agrees that it is important to include areas with five or more residential buildings intended for human occupancy and non-residential buildings occupied by five or more people, subject to the considerations discussed below. However, it is impractical and unduly burdensome to include outside areas or open structures where between five and 19 people may gather for at least 50 days in a 12-month period. Compliance with this requirement would require continuous monitoring and the NPRM contains no practical limitations on what would satisfy PHMSA's requirement to search for such a location.

INGAA also proposes that PHMSA use the edge of pavement instead of the "highway right-of-way" to determine whether a roadway intersects with the potential impact radius (PIR).[53] The edge of the pavement is more readily detected on imagery and provides a definitive boundary for public occupancy. INGAA suggests that PHMSA provide a single, dependable database from which to pull information on roadway classification. Finally, as described in Section VII, INGAA supports the inclusion of MCAs for MAOP reconfirmation as long as the reasonable modifications requested by INGAA are made.

1. PHMSA should limit the definition of an MCA to only those pipeline segments that are instrumented inline inspection segments.

PHMSA's definition of an MCA in proposed § 192.3 is overly broad because it exceeds the scope of the proposed substantive regulations that reference an MCA.[54] Proposed §§ 192.624 and 192.710 are limited to those segments that "can accommodate inspection by means of instrumented inline inspection tools (i.e. "smart pigs")." PHMSA should include the

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[53] The PIR is defined in 49 C.F.R. § 192.903 as "the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r=0.69* (square root of p*d2)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches."

[54] PHMSA states in the preamble of the NPRM that it also intends to apply material verification requirements (proposed § 192.607) to MCAs. NPRM at 20,812. However, in the rule text, PHMSA only includes integrity assessments (proposed § 192.710) and MAOP verification requirements (proposed§ 192.624). This change is further supported by the OIRA redlines in which PHMSA acknowledged that it would no longer propose to apply material verification requirements to MCAs. PHMSA should correct the preamble text in the Final Rule.

same limitation in its § 192.3 definition of an MCA. INGAA offers the following changes to the definition of an MCA in § 192.3:[55]

Moderate Consequence areas means an onshore area that is within a potential impact circle ~~as defined in § 192.903~~ of an instrumented inline inspection segment, located outside of a HCA, Class 3 and 4 area containing:

Although PHMSA describes "instrumented inline inspection segments" in the preamble as "capable of inspection by internal inspection tools," "accommodate the passage of instrumented internal inspection devices," and "can accommodate inspection by means of instrumented inline inspection tools (*i.e.*, "smart pigs")," the agency fails to define the term in § 192.3.[56] INGAA recommends that PHMSA add the following definition to § 192.3 for the reasons explained in Section IX:

An instrumented inline inspection segment means a length of pipeline through which a free-swimming commercially available in-line inspection tool can travel without the need for any permanent physical modifications to the pipeline and (1) is capable of assessing the identified threat(s); (2) can inspect the entire circumference of the pipe; and (3) can record or transmit relevant, interpretable inspection data.

2. PHMSA Should Modify its MCA Definition.

a. PHMSA Should Amend the MCA Definition to Avoid Ambiguity Regarding Residential Structures.

In the NPRM, PHMSA appears to limit the application of its definition of an "occupied site" to commercial and public structures. The examples cited by PHMSA include religious facilities, office buildings, community centers, general stores, 4-H facilities, and roller skating rinks. Given that these facilities are all commercial buildings, and that a family of five likely would occupy its home for longer than the duration specified by PHMSA (five days a week for ten weeks a year), INGAA believes that PHMSA did not intend to include a residential building as an occupied site. INGAA proposes that PHMSA clarify that residential structures are accounted for separately for purposes of MCA determination to avoid any confusion. In particular, INGAA recommends that PHMSA achieve this clarification by amending the MCA definition in the following manner.

55 The legend for the redline is as follows: (i) black text represents existing, currently-effective regulations; (ii) red text (whether struck through or not) represents PHMSA's proposed changes as set forth in the NPRM; and (iii) blue text (whether struck through or not) represents INGAA's proposed changes to the PHMSA NPRM proposal.

56 NPRM at 20,734, 20,770, 20,772, 20,775, 20,790, 20,800, 20,811, 20,813, 20,815, 20,834 and 20,838; Proposed §§ 192.150(a), 192.624(a)(1)(iii), 192.624(a)(3)(iii), 192.710(a)(1)(ii), 192.710(c)(6), 192.921(a)(6) and 192.937(c)(6).

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INGAA proposes that PHMSA delete the stand-alone definition of "occupied site" in § 192.3 and integrate paragraph (2) of that definition, which addresses buildings, into the definition of MCA. PHMSA uses the same language and examples to define both an identified site[57] for HCAs and an occupied site for MCAs, with the one notable exception that the term "occupied site" applies to lower occupancy levels. Introducing a similar but different concept in § 192.3 would create unnecessary confusion.

Specifically, INGAA proposes that the reference to "an occupied site" be deleted from the MCA definition and that the words "a non-residential building that is occupied by five (5) to nineteen (19) persons on at least five (5) days a week for ten (10) weeks in any twelve (12) month period. (The days and weeks need not be consecutive.)" be substituted in its place. These are the words from paragraph (2) of the definition of "occupied site," except that the word "non-residential" is inserted before the word "building" and "nineteen" is added to clarify that a structure with twenty or more persons would be covered by an HCA. There is no need for the "occupied site" language to include residential buildings because these structures are captured already in the MCA definition as "buildings intended for human occupancy."[58]

b. PHMSA Should Remove "Outside Areas and Open Structures" From the Definition Of MCA.

PHMSA defines "occupied site" as "[a]n outside area or open structure that is occupied by five (5) or more persons on at least 50 days in any twelve (12) month period . . . or a building that is occupied by five (5) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period."[59] It is impractical and unnecessary to require pipeline operators to assess each potential impact radius for outside areas or open structures where between five and 19 people may gather. This task would be extremely difficult, if not impossible to complete, given the transient nature of these areas.

Outside or open areas with physically identifiable attributes that may attract large crowds such as stadiums, recreational facilities, or outdoor theaters are easily identifiable and covered by the § 192.903 analysis for an identified site. By contrast, outside or open areas where five to nineteen people may gather are likely less pronounced due to the limited number of people potentially gathering, the transient nature of their presence, and the physical attributes used to identify such areas. This information will be difficult to ascertain from commercially available data, because visitors may only stay for a brief period. As such, these sites may require frequent field verifications. These areas could conceivably include remote picnic areas, food trucks, park

[57] *See* 49 C.F.R. § 192.903.

[58] Proposed 49 C.F.R. § 192.3.

[59] Proposed 49 C.F.R. § 192.3.

benches, seasonal hunting blinds or camps, and are not areas where the "routine" presence of persons is expected.[60]

These open areas with no clear identifiable attributes are likely to be scattered in small segments along a pipeline and can be dynamic in nature, making identification very opportunistic. Identifying an outside area or open structure may require that an operator monitor the right-of-way almost continuously to determine the number of days that visitors are present at these locations. This may require operators to take additional steps, including conducting outreach to determine areas where people may potentially congregate, reviewing aerial imagery, developing a list of possible locations, obtaining higher quality imagery, and conducting frequent verifications in the field. Operators may need to monitor their right-of-way at frequencies far exceeding those that are required for an HCA, an area of higher consequence. Operators will not be able to identify these areas without committing significant resources. PHMSA could reduce this burden and improve overall safety by removing outside areas and open structures from its MCA definition.

c. If PHMSA Does Not Remove Outside Areas and Open Structures, the Agency Should Provide the Same Practical Limitations Offered to Operators For Identified Sites.

The regulatory risk of failing to identify a particular outside area is high for MCAs. If PHMSA does not remove outside areas and open structures from its definition of an occupied site, PHMSA should afford the same practical limitations with respect to MCAs that are offered to operators in determining identified sites.[61] In § 192.905(b), PHMSA allows operators to consider the information obtained from routine operational and maintenance activities along the pipeline in addition to information received from emergency response and planning activities.[62] If an operator does not have this type of information, it may justify its assessment of an identified site by using visible signs or listings on a map available from a federal or state agency.[63] In PHMSA's FAQ-18, the agency recognized practical limits on an operator's search for identified sites.[64] PHMSA stated that:

> An operator is expected to make a reasonable effort to identify sites meeting the criteria for "identified sites". The rule requires that operators consider information they glean from routine operations and maintenance activities along the pipeline

[60] In the NPRM, PHMSA characterized MCAs and HCAs as areas where the "routine" presence of persons is expected. Specifically, PHMSA stated it did not intend to repeal the grandfather clause for those pipeline segments outside of HCAs or MCAs where "the routine presence of persons is not expected," thereby characterizing HCAs and MCAs as areas where the "routine" presence of persons is expected. NPRM at 20814 (emphasis added).

[61] 49 C.F.R. § 192.905(b)(1) and (2).

[62] 49 C.F.R. § 192.905(b)(1).

[63] 49 C.F.R. § 192.905(b)(2).

[64] *See* PHMSA, Gas Integrity Management FAQ-18 (May 17, 2004), http://primis.phmsa.dot.gov/gasimp/faqs.htm.

> and from public officials responsible for safety or emergency response/planning who indicate to the operator that they would know of locations near the pipeline meeting these criteria. If no public officials have such knowledge, then the operator must identify facilities that either: have visible signs; are licensed by a Federal, State, or local government agency; or appear on a list or map available from such an agency.[65]

PHMSA should afford the same flexibility to operators conducting MCA surveys to determine an occupied site.[66]

B. PHMSA Should Include Timeframes For Incorporating Changes to Existing MCAs.

PHMSA does not specify how often an operator must incorporate the data used to identify MCAs into its plan. PHMSA's proposal would require operators to update the existing software associated with HCAs to accommodate MCAs. The PRIA fails to include the time or costs associated with the software upgrades. Given the logistical challenges and upgrades needed to identify an MCA, PHMSA should allow operators a minimum of five years initially to evaluate MCA areas for changes in conditions.

Similar to the requirements for HCAs, PHMSA should also allow operators one year from discovery of a newly identified MCA or a change to an MCA to include the updates in its integrity management plan.[67]

C. PHMSA Should Account For the Resources Specifically Required to Identify MCAs.

In its PRIA, PHMSA failed to account for the costs and time needed to identify MCAs, particularly outside areas and open structures. PHMSA stated in the PRIA that "[b]ecause operators must have already performed [an] analysis in order to have identified HCAs, or verify that they have no HCAs, PHMSA assumed that the cost of identifying MCAs is negligible compared to the cost of assessments and did not quantify the cost to identify MCAs."[68] In support of this assumption, PHMSA points to statements in INGAA's prior comments that operators are already applying integrity management measures outside HCAs due to over testing

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[65] PHMSA, Gas Integrity Management FAQ-18 (May 17, 2004), http://primis.phmsa.dot.gov/gasimp/faqs.htm; Pipeline Safety: Identified Sites as Part of High Consequence Areas for Gas Integrity Management Programs, 68 Fed. Reg. 42,458 (July 13, 2016) (OPS's Advisory Bulletin ADB-03-03).

[66] PRIA at 32, § 3.1.3.

[67] 49 C.F.R. 192.905(c)(1); *See also*, PHMSA, Gas Integrity Management FAQ-19 (May 17, 2004) and FAQ-20 (Aug. 17, 2004), http://primis.phmsa.dot.gov/gasimp/faqs.htm.

[68] PHMSA, Preliminary Regulatory Impact Assessment at 32 (Mar. 2016).

(the inspection or testing of pipeline mileage beyond the limits of a HCA).[69] While INGAA members have and will continue to apply integrity management principles to areas outside of HCAs, it is incorrect to assume that there are no additional costs to identify this new category of non-HCA locations.

Additional information is required to differentiate between an HCA and an MCA. The extra effort can be minor when the number of structures within a PIR is identified on a geographic information system (GIS) system. It requires much more information and analysis, however, to determine if there is a transition from four to five occupants (MCA threshold) or 19 to 20 occupants (HCA threshold) in a given structure. The additional surveillance and monitoring required to identify MCAs has cost implications. Surveying mobile sites (picnic tables, food trucks, etc.) and the associated population requires significant resources and time.

PHMSA has overlooked its obligation to assess the costs and benefits of any proposed safety standard[70] with respect to identifying the cost burden to identify MCA areas. The time and costs needed to identify MCA segments and maintain record keeping processes for activities are quite significant and different than the time and costs associated with INGAA's commitment to apply integrity management principles to the entire pipeline near population. Operators will have to commit resources in both the instrumented inline inspection segments and non-instrumented inline inspection segments to evaluate where MCAs exist.

Currently, an operator is not required to conduct specific occupancy counts for structures that contain fewer than 20 people. Under PHMSA's proposal, an operator would have to reevaluate those specific structures and then upload the data to a GIS system. On average, it would take at least 30 minutes per structure to determine the occupancy of a building, and this does not include the time needed to evaluate outside areas or open structures. It would take two to three days to update a company's GIS system with the new data and run the required analysis.[71]

In addition to its obligation to assess the reasonableness of any proposed standard based on the costs and benefits,[72] PHMSA also is required determine if other alternatives exist that provide the same level of safety more cost-effectively. PHMSA has not compared the NPRM against notable alternatives including INGAA's IMCI commitments and associated timetable.

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[69] INGAA Comments on ANPRM at 21 (Jan. 20, 2012).

[70] 49 U.S.C. § 60102(b).

[71] These costs are estimates for a system of approximately 10,000 miles of pipe.

[72] 49 U.S.C. § 60102(b).

D. PHMSA Should Permit Operators to Use the Edge of Pavement Rather Than the Highway Right-Of-Way To Determine if a Roadway Intersects With the PIR.

PHMSA should use the edge of pavement rather than the highway right-of-way to determine if the road intersects with the PIR. In the NPRM, PHMSA proposed that operators use the right-of-way of the highway when determining MCA locations. Highway right-of-way data is not readily available in the Federal Highway Administration's database and it is difficult to discern the right-of-way boundary from aerial imagery. Significant field verification would be necessary to validate the extent of the right-of-way, including research at local courthouses to examine the actual right-of-way agreements to determine the full extent of the right-of-way. The edge of pavement is more easily detected on imagery and in the field. This is a more definitive boundary for public occupancy and one that is readily available to all operators. Furthermore, for purposes of advancing the safety goals served by identifying this intersection, drivers and pedestrians are more likely to be on the pavement and near the edge of pavement rather than near the right-of-way boundary.

E. PHMSA Should Provide a Single Database as a Resource to Determine if Any of the Designated Roadways Included in PHMSA's Definition of an MCA Are in the PIR.

PHMSA should provide one database that operators can rely on to determine the correct classification of a roadway (designated interstate, freeway, expressway, and other principal four-lane arterial roadway) and the corresponding centerline of those roadways. In the NPRM, PHMSA refers operators to the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures* database (FHWA database). While the FHWA database is useful to determine how to classify roadways, it does not provide the exact location of the centerline or the right-of-way boundaries. The FHWA database is not updated on a set schedule similar to the census data used for Part 195. Further, PHMSA has acknowledged that the FHWA database is spatially inaccurate. In its revised information collection request for the National Mapping Pipeline System, PHMSA stated:

> Multiple commenters noted that the reference GIS layer supplied to determine the "right-of-way for a designated interstate; freeway, expressway, or other principal 4-lane arterial roadway as defined in the Federal Highway Administration's 'Highway Functional Classification Concepts' within its potential impact radius" was spatially inaccurate and could not be relied upon to definitively designate the right-of-way. PHMSA conducted a close examination of the reference layer and came to the same conclusion.[73]

[73] Pipeline Safety: Request for Revision of a Previously Approved Information Collection: National Pipeline Mapping System Program, 81 Fed. Reg. 40,757 (June 22, 2016).

PHMSA should provide or reference a single database that contains the classification of roadways. An operator could use this information to establish the location of the edge of pavement and ultimately determine if any PIR intersects with a designated roadway. Without a dependable database, operators would have to determine manually in the field the appropriate classification and location of a roadway, and the highway and right-of-way boundaries. An operator would then need to upload this data into its GIS system further increasing the cost and administrative burden of PHMSA's proposal. Such costs have not been captured in the PRIA.

F. PHMSA is Not Asking For the Correct Information About MCAs in the Proposed Annual Report.

PHMSA limits its proposal for MCAs in the substantive regulations, §§ 192.624 and 192.710, to instrumented inline inspection segments outside of Class 3 and 4 areas while the proposed Annual Report requests data on <u>all</u> MCA mileage. The data requested for the Annual Report should match the facilities that are subject to the substantive requirements.[74] Acquiring data about pipelines that are not instrumented inline inspection segments only for the purposes of a proposed summation table in the Annual Report is burdensome and unjustified.

G. PHMSA Has Failed to Include the Costs of Identifying MCAs in Its Estimate of the Information Collection Burden For the Revised Annual Report.

PHMSA has not accounted for the administrative costs of responding to the proposed MCA sections of the Annual Report. PHMSA's proposed revisions to the Annual Report include requiring operators to submit information on MCAs. In order to provide the requested information for the Annual Report, operators would first have to identify MCAs and then expend additional time and incur additional costs to segment their pipeline networks dynamically. These sections of the report include entries for the number of MCA miles, MAOP determination, internal inspection, pressure testing, anomaly repairs within a MCA segment, pressure test failures within a MCA segment, etc. Unlike the substantive provisions of the NPRM that apply only to instrumented inline inspection segments with MCAs, the reporting requirements for pipelines in MCAs make no distinction between instrumented inline inspection and non-instrumented inline inspection segments. PHMSA should revise its Parts B and L of the Annual Report, Form PHMSA F-7100.2-1 (proposed 2016), to require operators to report only MCA miles which are instrumented inline inspection segments.[75]

In its Paperwork Reduction Act analysis, PHMSA estimates that operators can collect the necessary information and answer the new questions in five hours for each report. PHMSA fails to recognize that completing the annual report is only the culmination of countless hours an operator will need to spend throughout the year segmenting, tracking and preparing its data so

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[74] *See* Proposed §§ 192.710 and 192.624.

[75] *See supra* Section V.A.1.

that the appropriate MCA data is available for timely reporting. INGAA has assessed the costs and time involved and submits that completing the report alone will take 20% more effort and time per report. On average, it now takes an operator 100 hours to complete an Annual Report. In 2015, 1,416 Annual Reports were filed.

PHMSA has not accounted for the administrative costs of responding to the proposed MCA sections of the Annual Report. PHMSA's proposed revisions to the Annual Report include requiring operators to submit information on MCAs. In order to comply, operators would first have to identify MCAs and then expend additional time and incur additional costs to segment their pipeline networks dynamically in order to provide the requested information for each section of the Annual Report. These sections include entries for the number of MCA miles, MAOP determination, internal inspection, pressure testing, anomaly repairs within a MCA segment, pressure test failures within a MCA segment, etc. Unlike the substantive provisions of the NPRM that apply only to instrumented inline inspection segments with MCAs, the reporting requirements for pipelines in MCAs make no distinction between instrumented inline inspection and non- instrumented inline inspection segments.

In its Paperwork Reduction Act analysis, PHMSA estimates that it will take operators an additional 5 hours to collect the necessary information and answer the new questions for each report. PHMSA fails to recognize that completing the annual report is only the culmination of countless hours an operator will need to spend throughout the year segmenting, tracking and preparing its data so that the appropriate MCA data is available for timely reporting. INGAA has assessed the costs and time involved and submits that completing the revised section of the report alone would take 16 hours per report per operator. Using the Department of Labor salary figure of $110 per hour cited by PHMSA and approximately 152 interstate operator identification numbers, INGAA submits that the changes to the report alone would create a burden of 2432 hours and $267,520 just for filling out the report itself. The estimated costs to identify an MCA are much more extensive. These costs are approximately $86,931,643 per year for interstate and intrastate operators as described in detail in INGAA's analysis of the PRIA (Attachment 6).[76]

[76] *See* Section XVI.

Annual Cost for MCA Identification

Component	Unit Cost	Mileage/Impacted Operators	Total Cost
Identifying and Digitizing Structures	$10,000 per Operator	942	$9,420,000
Occupied Site Identification and Residences with more than 5 people	3 Hour for every 1 miles for an engineer at $77.01	278,003[1]	$64,227,033
PHMSA Roadway Overlay	1-5 days per operator	942	$527,595
Operator built Roadway Centerline File	2 Hours per mile in Class 3 and 4 and .5 hours in class 1 and 2	278,003[1]	$12,757,015
Total Cost			**$86,931,643**

Source: RIA Table 3-32 of the RIA

1. Total Interstate and Intrastate non-HCA mileage

H. INGAA's Proposed Regulatory Text Relating to MCAs

INGAA suggests that PHMSA include the following definition of "instrumented inline inspection segment" in § 192.3:

> An instrumented inline inspection segment means a length of pipeline through which a free-swimming commercially available in-line inspection tool can travel without the need for any permanent physical modifications to the pipeline and (1) is capable of assessing the identified threat(s); (2) can inspect the entire circumference of the pipe; and (3) can record or transmit relevant, interpretable inspection data.

INGAA also recommends the following changes to PHMSA's proposed definition of moderate consequence area and an occupied site:

Moderate Consequence areas means an onshore area that is within a potential impact circle ~~as defined in § 192.903~~ of an instrumented inline inspection segment, located outside of a HCA, Class 3 and 4 area containing:

i. five (5) or more buildings intended for human occupancy;
ii. ~~an occupied site~~ a non-residential building that is occupied by five (5) to nineteen (19) persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.); or
~~iii. a right-of-way~~ the edge of pavement ~~for~~ of a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway as defined in the Federal Highway Administration's *Highway Functional Classification Concepts, Criteria and Procedures*~~, and does not meet the definition of high consequence area as defined in § 192.903.~~

The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either ~~an occupied site,~~ five (5) or more buildings intended for human occupancy, or the edge of pavement ~~for~~ of a designated interstate, freeway, expressway, or other principal 4-lane arterial roadway, to the outermost edge of the last contiguous potential impact circle that contains either ~~an occupied site,~~ five (5) or more buildings intended for human occupancy, or the edge of pavement ~~a~~

~~right-of-way for~~ of a designated interstate, freeway, expressway, or other principal 4-lane arterial roadway.

~~*Occupied site* means each of the following areas:~~

~~(1) An outside area or open structure that is occupied by five (5) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or~~

~~(2) A building that is occupied by five (5) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks.~~

VI. Records

A. PHMSA Should Define the Phrase "Traceable, Verifiable, and Complete."

PHMSA should codify INGAA's definition of "traceable, verifiable, and complete" (TVC), limit the applicability of the TVC standard to MAOP records, and acknowledge that any new recordkeeping or retention requirements can only be applied after the effective date of the Final Rule.

1. Background

The NTSB introduced TVC in two safety recommendations issued to the Pacific Gas & Electric Company (PG&E) after the September 2010 San Bruno gas transmission line incident. The NTSB's recommendations used these terms to describe the standard that PG&E should apply in reviewing the sufficiency of its MAOP records.[77] Specifically, NTSB advised PG&E to:

> Aggressively and diligently search for all as-built drawings, alignment sheets, and specifications, and all design, construction, inspection, testing, maintenance, and other related records, including those records in locations controlled by personnel or firms other than Pacific Gas and Electric Company, relating to pipeline system components, such as pipe segments, valves, fittings, and weld seams for Pacific Gas and Electric Company natural gas transmission lines in class 3 and 4 locations and class 1 and 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing. These records should be traceable, verifiable, and complete.
>
> Use the traceable, verifiable, and complete records located by implementation of Safety Recommendation P-10-2 (Urgent) to determine the valid maximum allowable operating pressure, based on the weakest section of the pipeline or component to ensure safe operation, of Pacific Gas and Electric Company natural gas transmission lines in class 3 and class 4 locations and class 1 and 2 high consequence areas that have not had a maximum allowable operating pressure established through prior hydrostatic testing.[78]

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[77] NTSB, Safety Recommendation to Mr. Christopher Johns, President, Pacific Gas and Electric Co., P-10-2, P-10-3 (Jan. 3, 2011), http://www.ntsb.gov/safety/safety-recs/recletters/P-10-002-004.pdf.

[78] NTSB, Safety Recommendation to Mr. Christopher Johns, President, Pacific Gas and Electric Co., P-10-2, P-10-3 (Jan. 3, 2011), http://www.ntsb.gov/safety/safety-recs/recletters/P-10-002-004.pdf.

The NTSB did not define the terms "traceable, verifiable, and complete" in its safety recommendations and did not use the word "reliable."

On January 10, 2011, PHMSA responded to a separate NTSB safety recommendation by issuing an Advisory Bulletin reminding operators of their obligation under the pipeline safety regulations to perform detailed risk analyses that integrate data and information from the entire pipeline system when calculating MAOP (2011 Advisory Bulletin).[79] PHMSA stated that pipeline operators should ensure that any MAOP-related records are "reliable."[80] PHMSA also borrowed the language from NTSB's safety recommendations to PG&E and stated that these records "shall be traceable, verifiable, and complete."[81] PHMSA stated that pipeline infrastructure records that reflect a pipeline's physical and operational characteristics "should be traceable, verifiable, and complete to meet §§ 192.619 and 195.302."[82] PHMSA's 2011 Advisory Bulletin did not change any of the regulations in Part 192 or create any legally-enforceable obligations concerning the records necessary to substantiate MAOP.

On January 3, 2012, the President signed the 2011 Act into law. The 2011 Act included a mandate in Section 23 requiring gas transmission pipeline operators to verify records for pipelines in certain areas to determine if they have sufficient information to substantiate the MAOP of their pipeline systems.[83] Those operators also had an obligation to report the results of that review to PHMSA.[84] The obligations imposed by Section 23 arose solely from the 2011 Act and did not change the legal effect of NTSB's prior safety recommendations to PG&E or the 2011 Advisory Bulletin.

On May 7, 2012, PHMSA issued a second Advisory Bulletin (2012 Advisory Bulletin) that provided affected gas transmission line operators with guidance in response to the enactment of Section 23. The 2012 Advisory Bulletin reminded pipeline operators to verify their MAOP

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[79] Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation, 76 Fed. Reg. 1504 (Jan. 10, 2011).

[80] Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation, 76 Fed. Reg. 1504, 1506 (Jan. 10, 2011).

[81] Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation, 76 Fed. Reg. 1504, 1506 (Jan. 10, 2011). INGAA notes that although PHMSA used the word "shall" in its Advisory Bulletin, the agency cannot introduce new requirements in a guidance document. Agencies must use the Code of Federal Regulations to create new requirements. Guidance documents do not have the force of law.

[82] Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation, 76 Fed. Reg. 1504, 1507 (Jan. 10, 2011).

[83] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 § 23, Pub. Law. No. 112-90, 125 Stat. 1904, 1918 (2012) (codified at 49 U.S.C. § 60139(a)).

[84] 49 U.S.C. § 60139(b).

records and "take action as appropriate to assure that all MAOP and MOP are supported by records that are traceable, verifiable, and complete."[85] As part of the Advisory Bulletin, PHMSA offered guidance on the meaning of "traceable, verifiable, and complete."[86]

> 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, 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 line 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 pipe 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 an individual who would have reason to be familiar with the test or inspection.
>
> Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking. 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 pipe 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.

[85] Pipeline Safety: Verification of Records, 77 Fed. Reg. 26,822, 26,823 (May 7, 2012).

[86] Pipeline Safety: Verification of Records, 77 Fed. Reg. 26,822, 26,823 (May 7, 2012).

> PHMSA is aware that other types of records may be acceptable and that certain state programs may have additional requirements. Operators should ensure all records establish confidence in the validity of the records. If a document and records search, review, and verification cannot be satisfactorily completed to meet the need for traceable, verifiable, and complete records, the operator may need to conduct other activities such as in-situ examination, measuring yield and tensile strength, pressure testing, and nondestructive testing or otherwise verify the characteristics of the pipeline to support a MAOP or MOP determination.[87]

PHMSA did not define "reliable."[88]

Starting with the 2013 annual reporting cycle, PHMSA required gas transmission operators to submit data identifying the number of miles for which an operator did not have "traceable, verifiable, and complete records demonstrating that the criteria of the MAOP determination have been met."[89]

2. PHMSA Should Codify INGAA's Proposed Definition of "Traceable, Verifiable, and Complete."

PHMSA must define TVC in the pipeline safety regulations to provide regulatory certainty and create a basis for consistent compliance and enforcement across all pipeline operators. The agency referenced TVC 31 times in the NPRM, including in seven separate regulations, but did not define the phrase.[90] Although PHMSA has offered definitions of TVC in the 2012 Advisory Bulletin, guidance documents are not regulations and do not have the force of law. By failing to offer a concrete definition, PHMSA is introducing unnecessary ambiguity into the pipeline safety regulations and encouraging frequent and inconsistent reinterpretation. INGAA members have committed extensive resources over the last four years to determine whether their MAOP records meet PHMSA's guidance on TVC.

INGAA proposes the following definition of a traceable, verifiable, and complete record using PHMSA's 2012 guidance as a foundation:

> *Traceable, verifiable, and complete* means that a single record or a combination of records: (1) can be linked to original information about a pipeline segment or facility and is finalized as evidenced by a signature,

[87] Pipeline Safety: Verification of Records, 77 Fed. Reg. 26,822, 26,823 (May 7, 2012).

[88] Pipeline Safety: Verification of Records, 77 Fed. Reg. 26,822, 26,823 (May 7, 2012).

[89] Instructions for Form PHMSA F 7100.2-1 at 18 (revised Oct. 2014), http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Forms/GT_GG_Annual_Instructions_PHMSA_F_7100.2_1_(rev10_2014).pdf.

[90] *See* Proposed 49 C.F.R. §§ 192.485, 192.607, 192.619, 192.624, 192.713, 192.933, and the retention requirements listed in Appendix A.

> date, or other appropriate marking or (2) has other similar characteristics that support its validity. A single record can be traceable, verifiable, and complete. However, in some situations, complementary, but separate, documentation may be necessary. In determining whether a record is traceable, verifiable, and complete, due consideration shall be given to the standards and practices in effect at the time the record was created.

3. PHMSA Should Remove the Word "Reliable"

INGAA's proposed definition does not include the word "reliable," and PHMSA should remove "reliable" from any definition or discussion of TVC because it is an unnecessary adjective. Documents that are "traceable, verifiable, and complete" are "reliable." There is no need to add the word "reliable." If a document can be linked to the original information about a pipeline segment and has a signature, date, or other appropriate marking, it is traceable and complete and can be relied upon by both operators and PHMSA.

4. PHMSA Should Accept a Single Record.

PHMSA should acknowledge that a stand-alone record will suffice and a complementary record is only necessary in cases where the operator is missing an element of traceable and complete. PHMSA defines "verifiable records" as "those in which information is confirmed by other complementary, but separate, documentation."[91] This language conveys that two records might be required to establish that an operator has an acceptable record. PHMSA has previously acknowledged that "a single quality record" is acceptable.[92] PHMSA should include language in the pipeline safety regulations that explicitly permits a stand-alone record.

5. PHMSA Should Modify Its Language Allowing the Use of an Affidavit.

PHMSA should allow operators to use affidavits when the original document is missing and a person with knowledge of the original test or inspection can attest to the content of the original document. PHMSA stated in its 2012 Advisory Bulletin that an affidavit must be "prepared and signed <u>at the time of the test or inspection</u>."[93] This condition negates the value of allowing an affidavit, because it is highly unlikely that the individuals involved in performing the tests would have completed an affidavit at that time.[94] PHMSA should allow an operator to use an affidavit if the affiant is familiar with the original test or inspection and can attest to the

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[91] Pipeline Safety: Verification of Records, 77 Fed. Reg. 26,822, 26,823 (May 7, 2012).

[92] Letter of from John Gale, PHMSA to Ms. Christina Sames, Vice President, Operations & Engineering, American Gas Association (July 31, 2012).

[93] Pipeline Safety: Verification of Records, 77 Fed. Reg. 26,822, 26,823 (May 7, 2012) (emphasis added).

[94] Pipeline Safety: Verification of Records, 77 Fed. Reg. 26,822, 26,823 (May 7, 2012).

contents of the original document regardless of when the person signs the affidavit.

B. PHMSA Should Include INGAA's Examples of Acceptable Records in the Preamble.

PHMSA should also include INGAA's examples of acceptable records in the preamble of its Final Rule.[95] These examples were developed through a Joint Industry Project spearheaded by multiple natural gas transmission operators. Citing these examples in the preamble to the Final Rule would provide operators with the necessary insight to determine the type of records that are deemed acceptable.

C. PHMSA's Application of the Phrase "Traceable, Verifiable, and Complete" to All Records Is Overbroad.

PHMSA has failed to include a reasoned basis to support its application of TVC to all records. In the NPRM, the agency proposed that "[e]ach operator must make and retain records that demonstrate compliance with [Part 192]" and "[r]ecords must be reliable, traceable, verifiable, and complete."[96] PHMSA included this proposed requirement in the general recordkeeping section, indicating its intent to apply the phrase "reliable, traceable, verifiable, and complete" to all records required under Part 192.[97] PHMSA refers to section 23 of the 2011 Act as its support for this universal application of TVC. NPRM at 20,808. Specifically, PHMSA states that the agency "has determined that an important aspect of compliance with [section 23] is to assure that records that demonstrate compliance with Part 192 are complete and accurate." NPRM at 20,808. Section 23 of the 2011 Act required verification only of records used to establish MAOP and pipeline operational and physical characteristics.[98] Section 23 did not address records demonstrating compliance with all regulatory requirements. This attempt to expand Congress's mandate beyond the plain language of the statute is not the product of reasoned decision making and must be removed from the NPRM.

PHMSA also cannot rely upon the NTSB recommendations as support for its proposal to apply TVC to all records. The NTSB limited the application of TVC to MAOP records in its safety recommendations cited by PHMSA.[99] In its recent comments in this docket, NTSB referred to the need for TVC records only in the context of MAOP records. NTSB stated that "PHMSA has determined that additional rules are needed to ensure that [the] records used to establish MAOP are reliable, traceable, verifiable, and complete."[100] PHMSA fails to provide an

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[95] *See* Attachment 4 of these comments.

[96] Proposed § 192.13(e).

[97] *Id.*

[98] 49 U.S.C. § 60139.

[99] NTSB, Safety Recommendation to Mr. Christopher Johns, President, Pacific Gas and Electric Co., P-10-2, P-10-3 (Jan. 3, 2011), http://www.ntsb.gov/safety/safety-recs/recletters/P-10-002-004.pdf.

[100] Letter from Christopher Hart, Chairman, NTSB to U.S. Dep't of Transportation at 6, Docket No. PHMSA 2011-

explanation for expanding the existing recordkeeping requirements and requiring operators to comply with TVC for all records, rendering this aspect of the NPRM to be arbitrary and capricious.[101]

The application of TVC to all records is unnecessary, unsupported and does not reflect reasoned decision-making. For example, in §§ 192.485, 192.713(d)(1)(i), and 192.933(a)(1), PHMSA proposes that the pipe and materials properties used in remaining strength calculations be documented by TVC records. NPRM at 20,830. PHMSA has not demonstrated why remaining strength calculations must be based on TVC records. Currently, when data is unavailable, PHMSA permits operators to utilize conservative values that are reasonably justified. PHMSA has not demonstrated that reliance on these conservative values is unsafe, and there is no evidence of any failures that have been linked to the use of these conservative values. In some situations, TVC records may not be possible. For example, the use of aerial photography as described in § 192.917(b)(1)(xxxiv) would not meet the proposed TVC definition. NPRM at 20,841. INGAA also questions how patrolling records could meet TVC. PHMSA has not drawn a rational connection between the facts found and the solution offered.[102] PHMSA also has not demonstrated that requiring TVC records is practicable, appropriate, or reasonable.[103] This aspect of the NPRM is arbitrary and capricious and is not the product of reasoned decision making.

D. PHMSA Cannot Enforce Recordkeeping Requirements Retroactively.

PHMSA should state affirmatively that it does not intend to apply its new recordkeeping requirements retroactively, particularly any requirements that involve design, construction, initial inspection, and initial testing. PHMSA proposes new recordkeeping requirements for class location, pipe material and design, pipeline components, welder qualification, and plastic pipe.[104]

0023 (June 6, 2016), https://www.regulations.gov/#!documentDetail;D=PHMSA-2011-0023-0148.

[101] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)(vacating as arbitrary and capricious final rule that rescinded regulations without adequate explanation); *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 839, 843 (D.C. Cir. 2006) (vacating agency rule because record evidence did not support existence of the problem the rule purported to address). .

[102] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)(vacating as arbitrary and capricious final rule that rescinded regulations without adequate explanation); *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 839, 843 (D.C. Cir. 2006) (vacating agency rule because record evidence did not support existence of the problem the rule purported to address).

[103] *Owner-Operator Indep. Drivers Ass'n v. FMCSA*, 656 F.3d 580, 589 (7th Cir. 2011) (vacating rule because agency failed to consider an issue it was statutorily required to address); *Pub. Citizen v. FMCSA*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) (vacating final rule for failing to consider impact of final rule on the health of drivers, a mandatory statutory consideration under organic statute). *Id*. (stating that "'the complete absence of any discussion' of a statutorily mandated factor 'leaves us with no alternative but to conclude that [the agency] failed to take account of the statutory limit on [its] authority,'" making the agency's reasoning arbitrary and capricious.") (citing *United Mine Workers v. Dole*, 870 F.2d 662, 673 (D.C. Cir. 1989)).

[104] *See* proposed 49 C.F.R. §§ 192.5(d) (class location), 192.13(e) (Part 192 compliance), 192.67 (steel pipe material), 192.127 (pipe design), 192.205(pipe components), 192.227(c) (welder qualifications), and 192.285(plastic

In § 192.67, operators would be required to "*acquire* and retain for the life of the pipeline the original steel manufacturing records that document tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured, including but not limited to yield strength, ultimate tensile strength, and chemical composition of materials for pipe in accordance with 192.55." NPRM at 20,828 (emphasis added). In § 192.127, operators would be required to "*make* and retain for the life of the pipeline records documenting pipe design to withstand anticipated external pressures and loads in accordance with § 192.103 and determination of design pressure for steel pipe in accordance with § 192.105. NPRM at 20,828 (emphasis added). In § 192.205, operators would be required to "*acquire* and retain records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart." NPRM at 20,829 (emphasis added). Finally, in § 192.5, PHMSA proposes to require operators to retain records for the initial determination of a class location and subsequent changes for the life of the pipe.

PHMSA's use of "acquire" or "make" in the proposed regulations suggests that the agency intends to enforce these proposed recordkeeping requirements retroactively, directing an operator to obtain original information once the NPRM is finalized and becomes effective. If operators were not required to retain manufacturing and testing records previously, then it would be difficult to make or acquire those documents now.[105] In some cases, it will be impossible to obtain original steel pipe or valve manufacturing records now, decades after the pipe was placed in the ground and after numerous transactions involving the transfer of pipeline assets. Typically, during an acquisition, the purchasing operator receives only the records that the transferring owner has maintained. These often are, at best, a subset of the original documents of the original operator. The records transferred are those that the selling operator was relying upon to demonstrate compliance with the applicable regulations. PHMSA fails to acknowledge this issue.

PHMSA does not have the legal authority to create retroactive recordkeeping requirements. Certain aspects of the pipeline safety regulations cannot be applied retroactively. In the Natural Gas Pipeline Safety Act of 1968, Congress prohibited the application of design requirements to pipelines already in existence at the time the standard was adopted.[106] The only

pipe joiner qualifications).

[105] Prior to the enactment of the federal pipeline safety regulations in 1968, the ASME B31.8 standard provided guidance on MAOP determinations. Recordkeeping was limited to test pressure and test fluid. In 1974, the Office of the Federal Register published a "Guide to Record Retention Requirements ("Guide"). Guide to Record Retention Requirements, 39 Fed. Reg. 10,772, 10,827 (Mar. 21, 1974). This Guide summarized the recordkeeping requirements that were expressly stated in Federal laws and regulations and listed the records that must be kept. For gas transmission pipelines, the Guide specified that operators must retain records of welding procedures, girth weld records, safety tests (pressure tests), uprating records, administration of the operations and maintenance plan, leak survey records, line patrol and inspection, and corrosion control records and maps. There were no express regulatory requirements to retain material records.

[106] Natural Gas Pipeline Safety Act of 1968, Pub. Law. No. 90-481, 82 Stat. 720, 721 (1968).

subparts of Part 192 that can be applied retroactively are subparts A (General), M (Maintenance), I (Requirements for Corrosion Control), L (Operations), K (Uprating), and O (Integrity Management).[107] Section 60104(b) of the Pipeline Safety Act states that "[a] design, installation, construction, initial inspection, or initial testing standard does not apply to a pipeline facility existing when the standard is adopted."[108] Several of PHMSA's newly proposed recordkeeping sections (§§ 192.67, 192.127, and 192.205) are part of non-retroactive subparts B, C, and D, respectively, and can be implemented prospectively only. PHMSA itself has acknowledged the prohibition on retroactively applying these provisions.[109] The non-retroactivity prohibition applies equally to recordkeeping requirements as well as substantive provisions. PHMSA should remove "acquire" or "make" from the proposed regulatory text and clarify that §§ 192.5, 192.67, 192.205, and 192.127 apply prospectively. PHMSA's failure to do so would violate the PSA's clear prohibition and is arbitrary and capricious.

As written, the NPRM would appear to subject operators to penalties if they do not have records for past events that were not required at the time of the event, even if the records are no longer obtainable. In this regard, the proposed regulations appear to require operators to do the impossible, in violation of the due process clause of the Fifth Amendment of the U.S. Constitution[110] and time-honored legal principles.[111]

PHMSA cannot apply § 192.13(e) retroactively. The 2011 Act did not give PHMSA express authority to collect all records retroactively. PHMSA has amended the general recordkeeping requirement to require operators to make and retain TVC records to demonstrate compliance with Part 192.[112] This proposal must apply prospectively only. PHMSA may have

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[107] *Id*; *In the Matter of Belle Fourche Pipeline Co.*, CPF No. 5-2004-5010, 2006 WL 6863724 (D.O.T. Dec. 11, 2006); 49 U.S.C. § 60104(b).

[108] 49 U.S.C. § 60104(b); 49 C.F.R. § 192.13(a).

[109] Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standards, 35 Fed. Reg. 13,248, 13,250 (Aug. 19, 1970); *see In the Matter of Belle Fourche Pipeline Co., Decision on Reconsideration*, CPF No. 5-2004-5010, 2009 WL 7810536, at *4 (D.O.T. Jul. 15, 2009); Letter from Richard L. Beam, Associate Director for Office of Pipeline Safety Regulations, Materials Transportation Bureau, to Mr. Alfred V. Colabella, Jr., PE (Nov. 7, 1984); Letter from Richard L. Beam, Associate Director for Office of Pipeline Safety Regulations, Materials Transportation Bureau, to Mr. Alfred V. Colabella, Jr., PE (Nov. 19, 1984); Operating Pressure for Platform Piping; Interpretation, Department of Transportation, Materials Transportation Bureau, Docket No. OPSO-35 (Oct. 15, 1976).

[110] *La. ex rel. Gremillion v. NAACP*, 366 U.S. 293, 295 (1961).

[111] PHMSA's interpretation of its regulations would be constrained by the doctrines *lex non intendit aliquid impossible* (which means "[t]he law does not intend anything impossible") and *lex non cogit ad impossibilia* (which means "[t]he law does not compel the doing of impossibilities"). Black's Law Dictionary at 912 (6th ed. 1990). *See, e.g.*, *Heong v. United States*, 112 U.S. 536 (1884); *In re Grand Jury Proceedings*, 744 F.3d 211 (1st Cir. 2014); *Woodard v. Custer*, 719 N.W. 2d 842, 881 n.56 (Mich. 2006). A clarification that the proposed records requirement shall apply only on a prospective basis would eliminate the confusion this would create.

[112] Proposed 49 C.F.R. § 192.13(e). In § 192.13(e), PHMSA proposed that all records must be "reliable, traceable, verifiable, and complete". As stated above, INGAA does not support the inclusion of reliable.

the authority to require additional testing and inspection activities if old records do not meet the new TVC standard proposed by INGAA, but it cannot penalize operators for failing to have TVC records before TVC was a regulatory requirement. Section 23 of the 2011 Act specified how operators of certain gas transmission lines are to verify the sufficiency of records relating to MAOP. Without express congressional authority, PHMSA cannot require operators to maintain records that they were not previously required to retain.[113] In the PRIA, PHMSA characterizes §§ 192.13(e) and 192.619(f) as applying to *future* records providing further support that the agency cannot enforce these new requirements retroactively.[114] The application of traceable, verifiable, and complete can only be prospective. PHMSA should also clarify that the new retention requirements apply prospectively, not retroactively.

E. PHMSA Also Should Clarify That the New Retention Requirements Apply Prospectively, Not Retroactively

PHMSA should clarify that the new retention requirements listed in Appendix A apply prospectively only. Although PHMSA characterizes the new retention requirements as a clarification, many of requirements in Appendix A actually represent a change from the existing pipeline safety regulations. For instance, operators were not previously required to retain class location records and would now be required to keep those records for the life of the pipeline. It is not practicable for operators to produce or recreate records that they were not previously required to maintain. The non-retroactivity provision in the PSA not only applies to the substantive safety standards relating to the design, installation, construction, initial inspection, and initial testing of gas pipeline facilities, but it also applies with equal force and effect to the related record requirements. PHMSA should amend § 192.13(e) and Appendix A to clarify that the new retention requirements apply only to records created after the effective date of the Final Rule.

F. PHMSA Erroneously Lists § 192.603(b) In Appendix A as a Lifetime Retention Requirement

PHMSA did not propose to change the text of § 192.603(b) in the NPRM; however, the agency describes that regulation in its proposed "Records Retention Schedule for Transmission Pipelines" (Appendix A) as having a lifetime recordkeeping requirement. NPRM at 20,851. Section 192.603(b) states that "[e]ach operator shall keep records necessary to administer the procedures established under § 192.605."[115] Section 192.605 represents a pipeline operator's obligation to prepare and follow procedures for operation, maintenance, and emergency response

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[113] "Retroactivity is not favored in the law . . . a statutory grant of legislative rulemaking authority will not, as a general matter, be understood to encompass the power to promulgate retroactive rules unless that power is conveyed by Congress in express terms." *Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 (1988) (internal citation omitted).

[114] PHMSA, Preliminary Regulatory Impact Assessment at 97 (Mar. 2016) (PRIA).

[115] 49 C.F.R. § 192.603(b).

activities.[116] There is no discussion of this change to § 192.603(b) in the preamble of the NPRM. The regulatory text, structure, and history of Part 192 do not support the notion that an operator must keep records collected under §192.603(b) for the life of the pipe.

Several provisions of the current pipeline safety regulations explicitly require operators to retain records for the life of a pipeline; however, section 192.603(b) is not one of these provisions.[117] PHMSA does not include any explicit record retention period in § 192.603(b). The fact that other Part 192 regulations[118] prescribe a lifetime record retention period completely undermines the argument that § 192.603(b) can be interpreted to have such an obligation. By including a lifetime retention requirement in at least five separate regulations, PHMSA clearly has demonstrated its approach for establishing a lifetime recordkeeping requirement in a regulation. The omission of a similar retention requirement for § 192.603(b) indicates that there is no such obligation.

Interpreting § 192.603(b) as creating a lifetime recordkeeping requirement produces unnecessary conflicts with other provisions in Part 192. There are numerous regulations in the operations and maintenance section of the regulations that contain specific recordkeeping retention requirements. These provisions would be unnecessary if § 192.603(b) truly contained a lifetime recordkeeping requirement. For example, the five-year record retention provision for certain maintenance activities conducted by transmission line operators in § 192.709 would serve no purpose if PHMSA intended to create an all-encompassing lifetime recordkeeping requirement in § 192.603(b) for all operations and maintenance activities.

Finally, the regulatory history does not suggest that PHMSA or its predecessors intended to adopt a lifetime recordkeeping requirement in § 192.603(b). This section was part of the original federal pipeline safety regulations in 1970, and was derived from section 850.2(c) of the USA Standard Code for Pressure Piping, Gas Transmission and Distribution Systems (USAS B31.8-1968 ("B31.8")).[119] Like the original federal rules, B31.8 required operators to keep certain records for the life of a pipeline. However, section 850.2(c), the section most closely aligned with § 192.603(b), did not include a specific record retention period. There is no evidence in the rulemaking history that PHMSA's predecessor altered that understanding when it included § 192.603(b) in the pipeline safety regulations.

Nor is there any indication that PHMSA or its predecessors took the position that § 192.603(b) imposed a lifetime recordkeeping requirement in the decades that followed.

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[116] *See* 49 C.F.R. § 192.605.

[117] *See* § 192.14(b) (conversion of service), § 192.243(f) (non-destructive testing), § 192.491 (corrosion control records), § 192.517 (records for testing requirements), and § 192.620(c)(7) (alternative MAOP).

[118] *Id.*

[119] Establishment of Minimum Standards, 35 Fed. Reg. 13,185, 13,248 (Aug. 19, 1970).

PHMSA issued countless interpretations that cited § 192.603(b) but never characterized that particular provision as requiring operators to keep records for the life of the pipe.[120]

PHMSA has stated that that § 192.603(b) includes a lifetime recordkeeping requirement in only one recent interpretation, and INGAA submits that this decision is incorrect. On January 23, 2015, after NTSB issued its safety recommendations to PG&E regarding records and Congress enacted the MAOP verification mandate in section 23 of the 2011 Act, PHMSA issued an interpretation to the California Public Utilities Commission (CPUC) covering § 192.603(b). In it, PHMSA stated that "[s]ections 192.517 and 192.603 require that *all records* regarding the pipeline MAOP determination be *kept for the life of the pipeline segment*, including records of pipe properties, pipeline component properties, pressure test records, class location studies, current class location designation, and operating history."[121]

This interpretation of § 192.603(b) is not supported by the text, structure, or history of the regulation. Section 192.517 does not require an operator to retain *all* pressure test records for the life of the pipe. This particular provision only requires an operator to retain certain pressure test records for the life of the pipe.[122] After the agency issued this interpretation, PHMSA updated its enforcement guidance for Part 192 which again did not characterize § 192.603(b) as having a lifetime recordkeeping requirement. PHMSA stated that "when a regulation does not specifically require records, then paragraph § 192.603(b) can be used when appropriate records have not been kept."[123] The guidance was published in December 2015 and did not indicate that § 192.603(b) requires an obligation to keep records for the life of the pipe. INGAA asserts that the 2015 interpretation to CPUC was incorrect and that the text, structure, and history of § 192.603(b) does not support PHMSA's position that this particular regulation includes a lifetime recordkeeping requirement.

If it is PHMSA's intention to attach a lifetime retention requirement to the general recordkeeping requirements in § 192.603(b), then PHMSA must evaluate the burden of doing so under the Paperwork Reduction Act. In the NPRM, PHMSA failed to consider the additional burden of making all operations and maintenance records a lifetime retention requirement.

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[120] *See* Letter from Joseph Caldwell, OPS to Allan Anderson, P.E., Henningson, Durham & Richardson, PI-72-031 (July 17, 1972); Letter from Joseph Caldwell, OPS to John Searcy, Tennessee Public Service Commission, PI-74-0145 (Nov. 6, 1974); Memorandum from Richard Beam, Associate Director of Pipeline Safety Regulation, PI-83-0101 (Jan. 26, 1983); Letter from Cesar De Leon, OPS to Gerald Classen, K N Energy, Inc., PI-93-036 (July 15, 1993); Letter from George Tenley, Pipeline Safety to Albert Richardson, Tenneco Gas, PI-93-047 (Aug. 5, 1993).

[121] Letter from Jeffrey Wiese, Pipeline Safety to Joseph Como, California Public Utilities Commission at 3, PI-14-0005 (Jan. 23, 2015) (emphasis added).

[122] Section 192.517 requires an operator to retain records for each test performed under § 192.505 and § 192.507 for the life of the pipe. This requirement does not include all tests under subpart J.

[123] PHMSA, Operations & Maintenance Enforcement Guidance, Part 192 Subparts L and M at 6 (Dec. 7, 2015), http://phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/O_M_Enforcement_Guidance_Part192_12_07_2015.pdf.

INGAA urges PHMSA to remove § 192.603(b) from its Appendix A or, at a minimum, state that those records collected under this general provision should be retained "as specified in this appendix." There is no need to require operators to retain records under the general recordkeeping requirements for the life of the pipe if other portions of the code direct operators to retain records for a more limited duration.

G. PHMSA Omitted Its Proposed Changes to Recordkeeping and Retention Requirements in Its Information Collection.

In the NPRM, PHMSA included a summary of the five information collection requests that will need to be updated to incorporate the changes proposed in the NPRM. NPRM at 20,822. One of the information collection requests subject to revision is the "Recordkeeping Requirements for Gas Pipeline Operators."[124] This particular information collection represents PHMSA's general authority to require natural gas pipeline owners and operators to maintain records, make reports, and provide information to the agency. PHMSA limited the changes made by this NPRM to the addition of gathering line operators that will be newly subject to recordkeeping requirements. NPRM at 20,822. PHMSA failed to update its burden estimate and information collection request to reflect all of the new recordkeeping requirements proposed in the NPRM.

In its Supporting Statement submitted to the OMB, which will review the Information Collection request, PHMSA limits the scope of the revision to the addition of 100 gathering line operators that will now be required to collect records and an additional six burden hours per respondent to "create and maintain records associated with Emergency Planning requirements."[125] Pursuant to the proposals in the NPRM, all natural gas transmission operators will now have to collect new records and change their process to retain records per PHMSA's proposed § 192.13 and Appendix A. PHMSA must account for the actual time and costs involved to comply with these new recordkeeping requirements prior to seeking approval from OMB.

[124] OMB Control No. 2137-0049.

[125] NPRM at 20,823; Dep't of Transportation, Supporting Statement at 4, OMB Control No. 2137-0049 (Part A.15).

H. Proposed Regulatory Text Relating to Records

§ 192.3-Definitions

Traceable, verifiable, and complete means that a single record or a combination of records: (1) can be linked to original information about a pipeline segment or facility and is finalized as evidenced by a signature, date, or other appropriate marking or (2) has other similar characteristics that support its validity. A single record can be traceable, verifiable, and complete. However, in some situations, complementary, but separate, documentation may be necessary. In determining whether a record is traceable, verifiable, and complete, due consideration shall be given to the standards and practices in effect at the time the record was created.

§ 192.5 Class Locations.

[…]

(d) For transmission pipelines, each operator must retain ~~R~~records for the life of the pipeline that are created after *[the effective date of the Final Rule]* ~~transmission pipelines documenting class locations~~ and demonstrat~~eing~~ how an operator determined a class location~~s~~ ~~in accordance with this section must be retained for the life of the pipeline~~.

§ 192.13 What general requirements apply to pipelines regulated under this part?

~~(e) Each operator must make and retain records that demonstrate compliance with this part.~~
~~(1) Operators of transmission pipelines must keep records for the retention period specified in appendix A to part 192.~~
~~(2) Records must be reliable, traceable, verifiable, and complete.~~
~~(3) For pipeline material manufactured before *[effective date of the final rule]* and for which records are not available, each operator must re-establish pipeline material documentation in accordance with the requirements of § 192.607.~~

§ 192.619-Maximum allowable operating pressure: ~~Steel or plastic pipelines~~

[…]

(f) Operators must maintain all records necessary to establish and document the MAOP of each pipeline as long as the pipe or pipeline remains in service. Records that establish the pipeline MAOP, include, but are not limited to design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam type, and other related data. Records must be ~~reliable,~~ traceable, verifiable, and complete.

§ 192.67-Records: Materials

For transmission pipe manufactured after *[effective date of the final rule]*, ~~E~~each operator ~~of transmission pipelines~~ must ~~acquire and~~ retain for the life of the pipeline the original steel pipe manufacturing records that document tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured~~, including, but not limited to, yield strength, ultimate tensile strength, and chemical composition of materials for pipe in accordance with § 192.55~~.

§ 192.127 Records: Pipe design

For transmission pipe manufactured after *[effective date of the final rule]*, ~~E~~each operator ~~of transmission pipelines~~ must ~~make and~~ retain for the life of the pipeline records documenting pipe design to withstand anticipated external pressures and loads in accordance with § 192.103 and determination of design pressure for steel pipe in accordance with § 192.105.

§ 192.205-Records: Pipeline components

For valves manufactured after *[effective date of the final rule]* and used in connection with transmission pipelines, ~~E~~each operator ~~of transmission pipelines~~ must ~~acquire and~~ retain records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi or greater, manufactured after *[effective date of the final rule]*, must have records documenting the manufacturing specification in effect at the time of manufacture ~~including, but not limited to, yield strength, ultimate tensile strength, and chemical composition of materials.~~

Appendix A to Part 192-Records Retention Schedule for Transmission Pipelines

Appendix A summarizes the Part 192 records retention requirements. These retention requirements apply to records created after *[the effective date of the Final Rule.]* ~~As required by § 192.13(e), records must be readily retrievable and must be reliable, traceable, verifiable, and complete.~~

VII. MAOP Reconfirmation (§ 192.624)

Under § 192.624 of the proposed rule, PHMSA proposes to require MAOP reconfirmation for pipelines in HCAs, Class 3 or 4 locations or segments in MCAs that can accommodate "instrumented inline inspection tools" and:

1) have experienced an in-service incident since its most recent subpart J hydrostatic test due to an original manufacturing, installation, fabrication or construction-related defect or cracking-related threat such as seam cracking, girth weld cracking, etc.; or

2) the MAOP was established in accordance with 49 C.F.R. § 192.619(c) before the effective date of the Final Rule.[126]

PHMSA also would require MAOP reconfirmation for pipelines in HCAs or Class 3 or 4 locations where operators lack reliable, traceable, verifiable and complete pressure test records.[127]

The NPRM proposes six methods for confirming MAOP, including pressure test,[128] engineering critical assessment (ECA), pipe replacement, pressure reduction, pressure reduction for segments with small potential impact radius and diameter, and alternative technology.[129] For certain situations set forth in proposed § 192.624(c)(1)(ii), the pressure test must be a spike test under proposed § 192.506.

INGAA agrees that it is important to have a sound engineering basis to establish MAOP to ensure safe operation. INGAA commits to reconfirm[130] MAOP on pipelines that have not been subjected to Subpart J test levels,[131] lack TVC pressure test records in highly populated

[126] Proposed 49 C.F.R. § 192.624(a)(1)-(3).

[127] Proposed 49 C.F.R. § 192.624(a)(2).

[128] Proposed § 192.624(c)(1). The proposed rule allows pressure testing under Subpart J. Pressure testing is a broad category that covers testing with water, or hydrostatic testing as well as gas testing. Gas testing levels are applicable in limited applications. INGAA members will use hydrostatic testing when pressure testing under this rulemaking.

[129] § 192.624(c)(1)-(6).

[130] INGAA is using the term "reconfirmation" as it appears in the 2011 Act, 49 U.S.C. § 60139(c)(1)(A) to denote that operators will be reconfirming MAOPs that were confirmed in the early 1970s under the then existing version of § 192.607. This version of § 192.607 was removed in 1996. Regulatory Review; Gas Pipeline Safety Standards, 61 Fed. Reg. 28,770, 28,780 (June 6, 1996).

[131] INGAA uses the term "Subpart J test levels" to include pipelines that were tested prior to the effective date of Subpart J but nonetheless were tested to the Subpart J pressure test levels (*i.e.*, 1.25 x MAOP). To document these earlier tests, operators relied on the records required by the standards and practices in effect at the time the record was created.

areas (HCAs and Class 3 and 4 locations),[132] and MCA segments operating at greater than 30% SMYS that can accommodate instrumented inline inspection tools. PHMSA's proposal for MAOP reconfirmation would be technically feasible, reasonable, cost effective and practical with the following changes:

A. PHMSA Should Allow Operators to Use ILI to Reconfirm MAOP.

ILI is the only practical means to reconfirm MAOP for HCAs, class 3 and 4 and MCA segments. ILI is the reconfirmation method that provides the most information about the condition of the original pipeline manufacturing and construction features. It also provides the information in the most cost effective and environmentally friendly manner with the least service disruptions to pipeline customers. Pressure testing involves taking the pipe out of service, evacuating the gas, cutting the pipe, welding caps on both ends, filling the segment with water, and raising the pressure to the desired test pressure (hydrostatic testing). It provides limited information on the condition of the pipeline. It only provides a pass or fail result when testing pipelines. Hydrostatic testing leads to greater environmental impacts, including increased methane emissions and increased water consumption due to the acquisition, use, and disposal of hydrotest water. Since the pipeline must be taken out of service to conduct the test, the operator will need to curtail service for the duration of the test. Hydrostatic testing can also damage the pipe during testing by activating latent defects. ILI testing does not create these impacts. John Kiefner and K.M. Kolovlich, authors of one of the Battelle Final Reports cited by PHMSA in the preamble, state that "hydrostatic testing cannot be relied upon to eliminate [original manufacturing-related features.]"[133] In discussing two types of resident manufacturing-related features, cold welds and penetrators, the report states:

> It is reasonable to assume that all of the pipes containing these defects had been subjected to manufacturers' hydrostatic tests and/or subsequent in-situ hydrostatic tests to stress levels well in excess of their operating stress levels. It can be argued that these tests actually contributed to the formation of the leaks by causing the oxide to crack or disbond. So, hydrostatic testing cannot be relied upon to eliminate this threat.[134]

The diagnostic capability of ILI continues to improve. By the time a final rule is issued in this proceeding, ILI processes will have evolved further, providing PHMSA a sound engineering basis for using ILI for MAOP reconfirmation.

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[132] *See* Proposed § 192.624(a)(2).

[133] Kiefner, J. and K.M. Kolovich, ERW and Flash-Welded Seam Failures at ES-2, Final Report No. 12-139 (Sept. 24, 2012); NPRM at 20,814-815.

[134] Kiefner, J. and K.M. Kolovich, ERW and Flash-Welded Seam Failures at ES-2, Final Report No. 12-139 (Sept. 24, 2012).

B. In Order For Operators to Use ILI to Reconfirm MAOP, PHMSA Should Revise Its ECA and Alternative Technology Methods.

Proposed § 192.624 inappropriately mixes the concepts of determining the material strength of a pipe to support MAOP with the separate, ongoing subsequent process of managing the operations, maintenance, and integrity of the pipeline. Testing a pipeline's material strength validates the maximum operating pressure for the pipeline, and is different from the ongoing process of managing the threats and risks to a pipeline. PHMSA must not confuse these different processes and its regulations should differentiate between the two.

1. PHMSA Should Remove the Operating, Maintenance, and Integrity Management Requirements from its ECA Method 3 to Reconfirm MAOP.

INGAA supports ECA as a method to reconfirm MAOP. As proposed, ECA is overly complicated, burdensome and impractical. INGAA proposes PHMSA revise its ECA process to remove requirements that are related to operations, maintenance and integrity management, and do not belong in an MAOP reconfirmation provision. These modifications, including deleting consideration of threats, in-service degradation, loadings, and operational circumstances, etc., will ensure that an ECA is directed at reconfirming material strength and the size of original manufacturing and construction defects. INGAA requests PHMSA delete requirements that are relevant to integrity management and covered elsewhere in Part 192.[135] INGAA also proposes changes to ECA which clarify alternatives that operators can use to obtain necessary data using less burdensome methods that are equally effective and provide the same level of safety for reconfirming MAOP. The suggested edits remove duplicative regulatory language, such as references to RTVC, where the requirements of § 192.607 are already referenced. The modifications remove the burdensome pre-approval process for ILI and add unity plots as a method for operators to demonstrate that ILI is reliable for identifying and sizing actionable anomalies. With these modifications, the ECA method would permit an operator to use ILI to identify anomalies that, based on the combination of length and depth features, would have survived a Subpart J pressure test to 1.25 x MAOP in Class 1 and 2, and 1.5 x MAOP in Class 3 and 4.

PHMSA's proposed ECA seeks to address metallurgical fatigue. The 2006 Pipeline Research Council International study[136] provided guidance for operators to define the operating regime in which an in-depth evaluation of fatigue should be considered. This is embodied within ASME B31.8S and is an essential part of managing the ongoing integrity of a pipeline system.

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[135] *See* 49 C.F.R. Part 192, Subparts I, L, M and O.

[136] M.J. Rosenfeld, & J.F. Kiefner, Pipeline Research Council International Inc., Basics of Metal Fatigue in Natural Gas Pipeline Systems – A Primer for Gas Pipeline Operators, Contract PR-302-03152 (June 2006), Attachment 9 to INGAA's comments.

INGAA commissioned BMT Fleet, a recognized leader in fracture mechanics and fatigue analyses, to conduct a study of metallurgical fatigue in 2015. [137] One purpose of the study was to develop screening level criteria for use by gas pipeline operators in evaluating whether their pipeline operations were possibly in a fatigue regime, thus warranting a deeper analysis. Another purpose of the study was to develop an auditable process that operators could apply to show that they were not operating in a possible fatigue regime or that additional deeper analyses were needed using methods such as ASTM E1049 (2011), "Standard Practices for Cycle Counting in Fatigue Analysis." INGAA recommends that PHMSA incorporate by reference the BMT Fleet Report as a method to address fatigue.

INGAA requests PHMSA modify § 192.624(c)(3) consistent with the suggested regulation text below.[138]

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

(a) ***Applicable locations*.** The operator of a pipeline segment meeting any of the following conditions must establish the maximum allowable operating pressure using one or more of the methods specified in § 192.624(c)(1) through (6):

[…]

(c) ***Maximum allowable operating pressure determination*.** The operator of a pipeline segment meeting the criteria in paragraph (a) above must establish its maximum allowable operating pressure under one of the following methods.

[…]

(3) *Method 3: Engineering critical assessment* - Conduct an engineering critical assessment and analysis (ECA) to establish the material strength ~~condition~~ of the segment and maximum allowable operating pressure. An ECA is an analytical procedure, based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), and operating history. ~~operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections. The ECA must assess: threats; loadings and operational circumstances relevant to those threats including along the right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure~~

[137] BMT Fleet Technologies, Fatigue Considerations in Natural Gas Transmission (June 30, 2016), Attachment 7 to INGAA's comments.

[138] INGAA supports the inclusion of § 192.607, as modified by INGAA, in §192.624(a)(3) (i). By requiring operators to comply with §192.607 in order to avail themselves of ECA, PHMSA either is requiring an operator to accelerate compliance with §192.607 deadlines or is rendering the ECA method impracticable. *See* Section XIII.

~~processes; initial and final defect size relevance. The ECA must quantify the coupled effects of any defect in the pipeline.~~

(i) *ECA analysis*.

(A) The ECA must integrate and analyze the results of the material documentation ~~program~~ plan required by §192.607, if applicable.~~, and the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including but not limited to close interval surveys, coating surveys, and interference surveys required by subpart I, root cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by § 192.710 and subpart O.~~

(B) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure (PFP) of ~~each defect~~ actionable anomalies. The ECA must use the techniques and procedures in ~~Battelle Final Reports ("Battelle's Experience with ERW and Flash Weld Seam Failures: Causes and Implications" - Task 1.4)~~, Report No. 13-002 ("Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams" – Subtask 2.4), Report No. 13-021 ("Predicting Times to Failure for ERW Seam Defects that Grow by Pressure-Cycle-Induced Fatigue" – Subtask 2.5) ~~and ("Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures – Phase 1" – Task 4.5)~~ (incorporated by reference, *see* § 192.7) or other technically proven methods including but not limited to API RP 579-1/ASME FFS-1, June 5, 2007, (API 579-1, Second Edition) – Level II or Level III, CorLas™, BMT Fleet Technologies, Fatigue Considerations for Natural Gas Transmission Pipelines, Reference 30348.DFR, June, 2016 or PAFFC. The ECA must use conservative assumptions for crack dimensions (length and depth) and failure mode (ductile, brittle, or both) for the microstructure, location, type of defect, and operating conditions (which includes pressure cycling). ~~If actual material toughness is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then~~ T~~t~~he operator ~~must~~ can determine a representative Charpy v-notch toughness based upon their material documentation ~~program~~ plan ~~specified in~~ developed to comply with the requirements of § 192.607.~~ or use~~ The operator can use toughness data where available based on data it possesses or available through commercial data bases. When operators lack either toughness data or data from publically available databases, they may use conservative values for Charpy v-notch toughness as follows: body toughness of less than or equal to ~~5.0~~ 13 ft-lb and seam toughness of less than or equal to ~~1~~ 4 ft-lb.

(C) The ECA must analyze any metal loss defects not associated with a dent including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe to determine the predicted failure pressure (PFP). ASME/ANSI B31G (incorporated by reference, see § 192.7) or AGA Pipeline Research Committee Project PR–3–805 ("RSTRENG," incorporated by reference, see § 192.7) must be used for corrosion defects. Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth). When determining PFP for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used. ~~If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607.~~

(D) The ECA must analyze interacting defects to conservatively determine the most limiting PFP for interacting defects. Examples include but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

~~(E) The maximum allowable operating pressure must be established at the lowest PFP for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii) or § 192.620(a)(2)(ii).~~

(ii) *Use of prior pressure test.* If pressure test records as described in subpart J and § 192.624(c)(1) exist for the segment, then an in-line inspection program is not required, provided that the remaining life of the most severe defects that could have survived the pressure test have been calculated and a re-assessment interval has been established. The appropriate retest interval and periodic tests for time-dependent threats must be determined in accordance with the methodology in § 192.624(d) *Fracture mechanics modeling for failure stress and crack growth analysis.*

(iii) *In-line inspection*. If the segment does not have records for a pressure test in accordance with subpart J test levels and § 192.624(c)(1), the operator must develop and implement an inline inspection (ILI) program using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking. At a minimum, the operator must conduct an assessment using high resolution magnetic flux leakage (MFL) tool, a high resolution deformation tool, and either an electromagnetic acoustic transducer

(EMAT), circumferential MFL (CMFL) or ultrasonic testing (UT) tool, or a combination of these tools~~.~~

~~(A)~~ In lieu of the tools specified in paragraph § 192.624(c)(3)(i), an operator may use "other technology" if it is validated by a subject matter expert in metallurgy and fracture mechanics to produce an equivalent understanding of the condition of the pipe. ~~If an operator elects to use "other technology," it must notify the Associate Administrator of Pipeline Safety, at least 180 days prior to use, in accordance with paragraph (e) of this section and receive a "no objection letter" from the Associate Administrator of Pipeline Safety prior to its usage. The "other technology" notification must have:~~

~~*(1)* Descriptions of the technology or technologies to be used for all tests, examinations, and assessments including characterization of defect size crack assessments (length, depth, and volumetric); and~~

~~*(2)* Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and remediate defects discovered.~~

~~(B) If the operator has information that indicates a pipeline includes segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.~~

~~(C) If the pipeline has had a reportable incident, as defined in § 192.3, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with paragraph § 192.624(c)(3)(iii) includes an engineering evaluation program to analyze the susceptibility of girth weld failure due to lateral stresses.~~

(D) Inline inspection must be performed in accordance with § 192.493.

(E) The operator must use unity plots or equivalent methodologies to demonstrate the effectiveness of the ILI tools in identifying and sizing actionable manufacturing and construction-related anomalies. The operator must have a process for identifying outliers and following up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data or both. ~~All MFL and deformation tools used must have been validated to characterize the size of defects within 10% of the actual dimensions with 90% confidence. All EMAT or UT tools must have been validated to characterize the size of cracks, both length and depth, within 20% of the actual dimensions with 80% confidence, with like-similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the segment being evaluated.~~

~~(F) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and or subpart O, as applicable, and~~

~~must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the type defects and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.~~

(G) Anomalies detected by ILI assessments must be repaired in accordance with applicable repair criteria in §§ 192.713 and 192.933.

(iv) If the operator has reason to believe any pipeline segment contains or may be susceptible to cracks or crack-like defects due to assessment, leak, failure, or manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.624(d).

2. PHMSA Should Modify Its Alternative Technology Method 6 Proposal to Remove Procedural Hurdles.

In § 192.624(c)(6), PHMSA proposes that operators could use alternative technology to verify MAOP but only after notifying PHMSA 180 days in advance and after receiving "a no objection letter" from PHMSA. NPRM at 20,836-37. INGAA requests that PHMSA remove the case-by-case approval process that could take extensive time to complete. Section 60139(d)(2)(B) of the 2011 Act requires that PHMSA consider "other alternative methods, including in-line inspections, determined by the Secretary to be of equal or greater effectiveness" for conducting tests to confirm material strength of previously untested pipe.[139] As a practical matter, the procedure proposed in the NPRM will effectively preclude operators from using ILI to meet PHMSA's deadlines to reconfirm MAOP.

The alternative technology process is inconsistent with other aspects of the NPRM. For example, § 192.710(c) permits operators to use ILI for a variety of features similar to those being addressed in § 192.624 without any pre-approval process, provided that the ILI method provides "an equivalent understanding of the line pipe for each of the threats to which the pipeline is susceptible." Features identified by PHMSA in both § 192.710(c) and § 192.624 include cracking and crack-like defects.

[139] 49 U.S.C. § 60139(d)(2)(B) (2012).

The process proposed in § 192.624(c)(6) is patterned after PHMSA's special permit process. The special permit procedure has become so burdensome that some operators have stopped applying for special permits for class location changes and alternative MAOPs because the requirements, burden, uncertainty and time to secure such a permit make it impractical to utilize the advances for which the special permit was sought in the first place. When operators do apply for special permits, it takes months or years of data exchange with PHMSA to complete the process. INGAA does not want that same process and delay to be incorporated in this alternative technology §192.624(c)(6) process. Congress saw the need for industry to develop new and advanced techniques to reconfirm MAOP rather than relying solely on historical blunt tools, such as hydrostatic testing or other methods which are costly, less effective, and have significant impacts to people, pipeline customers, and the environment. This rulemaking should promote the development and adoption of technological advances, consistent with Congress's intent, rather than promote a process that will frustrate the development of these newer technologies.

In the PRIA, PHMSA recognizes the value of ILI for MAOP reconfirmation. The PRIA is premised on operators using ILI technology for MAOP reconfirmation on predominant parts of pipeline systems. PRIA, Table 3-5, p. 336. That presumption and the associated cost savings cannot be achieved using either the ECA or alternative technology methods as currently proposed in the NPRM.

INGAA proposes PHMSA revise § 192.624(c)(6) to allow for the use of technology providing an equivalent level of safety similar to proposed § 192.710(c)(7).

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

(a) ***Applicable locations*.** The operator of a pipeline segment meeting any of the following conditions must establish the maximum allowable operating pressure using one or more of the methods specified in § 192.624(c)(1) through (6):

[…]

(6) *Method 6: Alternative technology* - Operators may use an alternative technology ~~technical evaluation~~ process that provides a sound engineering basis for establishing maximum allowable operating pressure. When using alternative technology, the operator must demonstrate that the technology is capable of achieving the performance of a pressure test in Method 1~~. If an operator elects to use alternative technology, the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph (e) of this section. The operator must submit the alternative technical evaluation to PHMSA with the notification and obtain a "no objection letter" from the Associate Administrator of Pipeline Safety prior to usage of alternative technology …~~

If PHMSA does not change both § 192.624(c)(3) and § 192.624(c)(6), consistent with INGAA's comments, then it must revise its PRIA to reflect that operators will rely more on hydrotesting and less, if any, on ILI to reconfirm MAOP.

C. PHMSA Should Eliminate the Requirement That Operators Use a Spike Test to Reconfirm MAOP.

INGAA agrees with PHMSA's proposal to require MAOP reconfirmation for previously untested pipelines, including those operating under the grandfather clause. INGAA does not support the use of a spike test for MAOP confirmation and recommends PHMSA delete proposed §192.624(c)(1)(ii).

A spike test under proposed §192.506 is unnecessary to establish an adequate margin of safety for MAOP reconfirmation, which is the difference between the initial test pressure and the MAOP under which a pipeline can operate. A single Subpart J pressure test, or testing to Subpart J pressure test levels, is sufficient to establish the safety margin that is fundamental to MAOP. The initial pressure test serves as the starting point for managing the pipeline during its operational life. An operator uses ongoing operation, maintenance, and integrity management activities to manage the condition of the pipeline continually. If an operator determines that the condition of the pipeline has deteriorated, the operator evaluates the pipeline using proven methods to ensure safe continued operation, and, when necessary, repairs or replaces pipe to ensure that the safety margin is restored.

PHMSA's current proposal in § 192.506 and § 192.624(c)(1)(ii) to require spike testing to reconfirm MAOP goes beyond what is needed to establish an adequate margin of safety. A spike test exposes pipe to pressure levels higher than what the pipe experienced during the testing in the manufacturing mill and well-above the pressure at which the pipeline will ever operate. Pipeline operating pressure is controlled by relief valves and pressure control systems which prevent the pipe from ever significantly exceeding its MAOP, by either reducing compression or opening a valve.

It is well established in PHMSA's existing regulations and industry consensus standards that hydrostatic testing levels under Subpart J establish an adequate margin of safety between the test level and MAOP (that is maintained for the life of the pipeline).[140] The benefits and sufficiency of pressure testing at this level for purposes of establishing material strength are well documented in technical literature.[141] Features present from original manufacturing and

[140] 49 C.F.R. § 192.503; ASME B31.8-2012, Gas Transmission and Distribution Piping Systems, Code for Pressure Piping at 47, Section 841.3.2 and ASME B31.8-2007, Section 841.32.

[141] *See* ASME B31.8-2012, Gas Transmission and Distribution Piping Systems, Code for Pressure Piping; Duffy,

historical construction techniques are resident and do not grow in service unless acted upon by another threat, such as external corrosion, outside force, or pressure cycling. Each of these threats, including their interaction with a resident feature, is managed under ongoing operations, maintenance and integrity.

Testing a joint of pipe to the point of failure, which is referred to as a "burst test," illustrates why a Subpart J hydrostatic test to 1.25 x MAOP establishes an adequate safety margin. One INGAA member provided a report of a burst test for flash-welded pipe manufactured by AO Smith in 1949. This type of pipe would be "legacy" pipe using PHMSA's proposed definition. The pipe is 16 inches in diameter, with a 0.5 inch wall thickness and a grade of 52,000 ksi. The operator collected the following data during the burst test.

- The pressure in the pipe was increased and began to yield at 3,375 psi.
- The pressure was continually increased and the pipe ultimately failed at 4,385 psi.
- The pressure at which the pipe failed (burst) was 1.5 times the level at which the pressure test occurred. This is a factor of 1.5 above the 1.25 safety factor that is provided by the Subpart J test.
- Combining these results in a margin of safety between the MAOP and the burst pressure is a factor of 1.875.

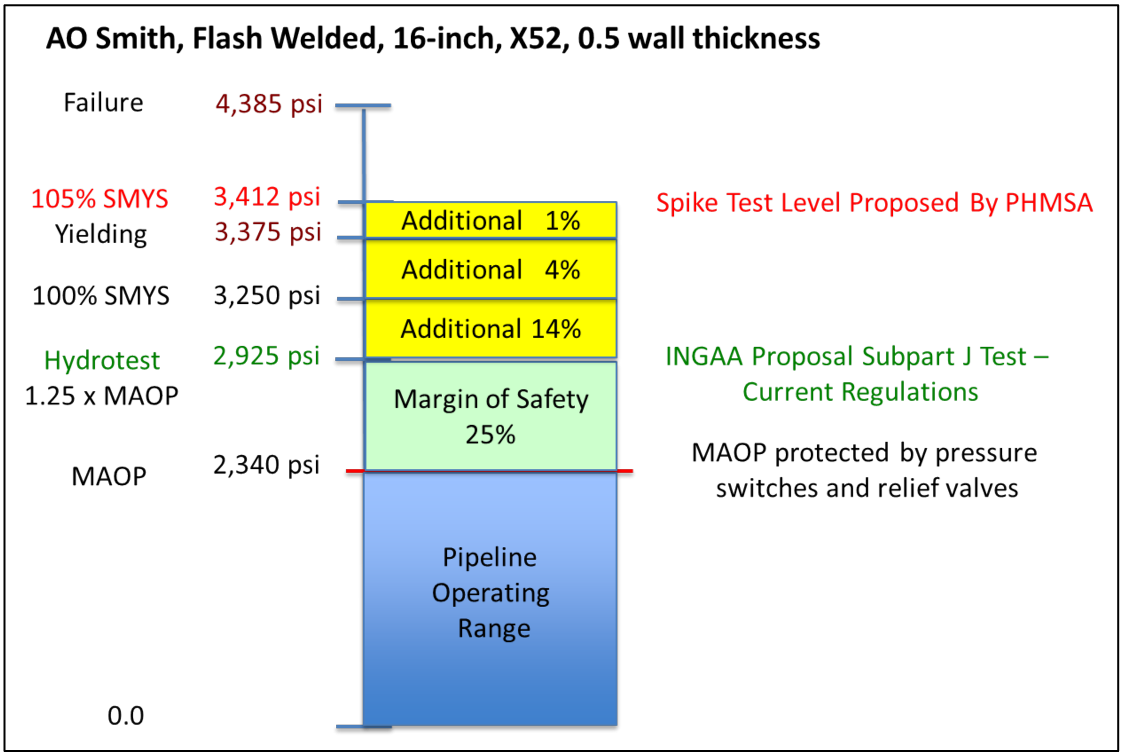
Given this information about the pipe, one can compute the following:

- The specified minimum yield strength of this pipe is 3,250 psi, using the design formula at §192.105(a).
- The MAOP for Class 1 pipe is 0.72 x SMYS or 2,340 psi.
- A Subpart J pressure test to 1.25 x MAOP is 2,925 psi

As depicted in Figure 1, a spike test would subject a pipeline to an unnecessarily high level of pressure compared to the pressure that the pipeline will ever experience over its life:

A.R., McClure, G.M. Maxey, W.A. and Atterbury, T.J., "Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test Pressure," Battelle Memorial Institute, PRC/AGA NG-18 Report L30050 (1968); Research and Special Projects Administration, U.S. Department of Transportation, Pipeline Safety Alert Notice, ALN-88-01 (Jan. 28, 1988); Research and Special Projects Administration, U.S. Department of Transportation, Pipeline Safety Alert Notice, ALN-89-01 (Mar. 1, 1989); Brian Leis, "Hydrotest Protocol for Applications Involving Lower Toughness Steels," IPC04-0665, ASME IPC Calgary, (Sept. 2004); API 5L, Specification for Line Pipe (1928 to date).

Figure 1



INGAA's proposed test pressure provides for a 25% safety margin above a pipeline's MAOP, which is controlled by relief valves and pressure control systems. The NPRM fails to present any record evidence or technical analysis that supports the higher proposed test pressure. The NPRM also omits any discussion or consideration of the factors PHMSA must consider in adopting a new safety standard.[142]

INGAA has demonstrated that its proposed test methods provide an adequate safety margin without any of the risks or additional costs associated with a spike test. A spike test is not required to establish an adequate margin of safety for MAOP reconfirmation, and PHMSA should eliminate spike testing from § 192.624(c)(1)(ii).

D. Pipelines That Have Experienced an In-Service Incident As a Result of the Listed Defects in § 192.624(A)(1) Should Not Be Subject to MAOP Reconfirmation.

INGAA does not support the application of MAOP confirmation to pipelines that have experienced an in-service incident as a result of specific defects. These defects, described in § 192.624(a)(1), are "an original manufacturing-related defect, a construction-, installation-, or

[142] 49 U.S.C. § 60102(b).

fabrication-related defect, or a cracking-related defect, including, but not limited to, seam cracking, girth weld cracking, selective seam weld corrosion, hard spot, or stress corrosion cracking."[143] An operator can evaluate the enumerated defects more effectively through ongoing operations, maintenance and integrity, not MAOP reconfirmation. The integrity and serviceability of a pipeline following an incident are restored through repairs, which also restore the original safety margin supporting the MAOP. The defects that PHMSA is concerned about are addressed under current IM regulations. There is no regulatory gap, since the listed defects will be addressed through IM. PHMSA should remove pipeline segments that have experienced a reportable in-service incident from its proposed § 192.624(a)(1).

Demonstrating material strength to support an MAOP is different from the ongoing management of threats on a pipeline. The two concepts, which often work in concert, should not be confused or conflated. MAOP confirmation is an initial, one-time, pre-service test of material strength that validates the maximum allowable operating pressure of the pipeline. Following this initial step, IM is the ongoing process for the life of the pipeline that continuously identifies and mitigates threats and identifies potential anomalies. Incidents resulting from an in-service failure related to unstable manufacturing and construction-related threats or cracking-related threats are best addressed under IM requirements. While the types of threats listed by PHMSA may pose a risk to the pipeline and should be addressed, these threats do not relate to the establishment of MAOP.

INGAA's proposal to use ILI to reconfirm MAOP will result in significantly lower emissions and have less impact on shippers and consumers of a natural gas pipeline because fewer hydrostatic tests will be required. A hydrostatic pressure test requires that a pipeline be taken out of service and that all natural gas be removed from the pipeline before it is filled with water and tested. The removal of natural gas from the pipeline results in methane releases into the atmosphere, the hydrostatic testing creates the need to acquire and dispose of water, and the shutdown of the pipeline can result in service disruptions and detrimental impacts to shippers and natural gas customers.

E. With a Few Modifications of PHMSA's Proposal, INGAA Accepts the Inclusion of MCAs in § 192.624.

Contrary to statements in the preamble, the PSA does not require MAOP reconfirmation for MCAs.[144] Nevertheless, INGAA supports MAOP reconfirmation for MCAs provided that PHMSA makes the key changes recommended by INGAA.

[143] Such defects, and the threat posed by such defects are the subject of IM regulations such as §§ 192.911, 192.917 and 192.933.

[144] 49 U.S.C. § 60139(c).

First, PHMSA should modify § 192.624(a) so that MAOP reconfirmation is only required in MCAs that operate greater than 30% of SMYS and can accommodate an "instrumented inline inspection tool," as defined by INGAA.[145] As outlined in the IMCI commitments, INGAA supports MAOP reconfirmation in MCAs for pipelines operating at greater than 30% of SMYS. There is much precedent for the low-stress threshold being established at 30% of SMYS, including PHMSA's own regulations. PHMSA established 30% of SMYS as a low stress threshold for integrity assessments in the gas integrity management regulations in 49 C.F.R. § 192.941(a). In addition, 30% of SMYS generally is accepted to be the "low-stress" boundary between leaks and ruptures for pipeline defects. ASME B31.8 also uses low stress threshold in multiple provisions, such as pressure testing and repairs. The Gas Research Institute developed a report examining the boundary between leaks and ruptures, which determined that pipelines operating at less than 30% of SMYS *leaked* if they failed while pipelines operating at greater than 30% of SMYS *ruptured* if they failed.[146] The Gas Technology Institute evaluated the leak rupture boundary in the late 2000s and developed a leak-rupture calculator.[147] This work confirms the 30% of SMYS threshold and provides an engineering method for using material properties data to estimate whether a leak or rupture will occur.

PHMSA must also make modifications that allow ECA, ILI and other alternative technologies to be feasible alternatives to reconfirm MAOP for MCAs. Without these modifications, operators will have to reconfirm MAOP solely by pressure testing which as explained below is more costly and has adverse environmental consequences. INGAA has requested sensible changes to the definition of MCA to allow operators to define the MCA area with reasonable certainty. INGAA also recommends that PHMSA make certain revisions to RTVC and codify a definition of the standard which will provide clarity for operators confirming MAOP under § 192.624(a)(2).[148]

F. PHMSA Failed to Comply With Congress's Requirement That It Consult With the Chairman of FERC and State Regulators.

Section 23 of the 2011 Act required PHMSA to consult with the Chairman of FERC and state regulators before establishing timeframes for the testing of previously untested pipes.[149] PHMSA was directed to take into account the impacts on public safety and the environment in addition to the costs and service disruptions involved.[150] It is not evident that PHMSA has

[145] See Section V of these comments.

[146] Gas Research Institute, Leak Versus Rupture Considerations for Steel Low-Stress Pipelines, GRI-00/0232 (Jan. 2001).

[147] Gas Technology Institute, Leak-Rupture Boundary Determination, Final Report (May 4, 2011) (Including Leak-Rupture Calculator and Training Manual).

[148] *See supra*, Section VII

[149] 49 U.S.C. § 60139(d)(3).

[150] *Id.*

consulted with the FERC or the states given that there is no discussion of such consultations in the preamble of the NPRM. Failure to consult with the Chairman of FERC and state regulators in establishing timelines for material strength testing constitutes a failure to comply with a statutory mandate and is arbitrary and capricious.[151]

G. PHMSA Failed to Consider Fully All of the Costs and Impacts of the Proposed Requirements.

Given the proposed limitations on the use of ILI to reconfirm MAOP as explained above, most INGAA members will be forced to rely on hydrostatic testing to meet the requirements of § 192.624, at least in the near term. Hydrostatic testing will require certain pipelines to be taken out of service, with significant impacts to the pipeline operator, its customers, and the natural gas and power markets. The PRIA does not account for these impacts.

In its PRIA, PHMSA places too much reliance on the lower cost of using ILI for MAOP confirmation in lieu of hydrostatic testing through either the ECA or alternative technology methods. The PRIA assumes that operators will reconfirm MAOP primarily through the use of ILI (approximately 90%) even though the effect of the proposed rule would force operators to use hydrostatic testing for virtually all segments in the near term, a far greater rate than 10 percent. If adopted as proposed, the impracticable pre-approval process in the alternative technology method and impracticable requirements of the ECA method will force industry to utilize hydrostatic testing.[152] The PRIA's assumptions are erroneous and the result in a gross underestimation of the cost of the proposed rule.[153]

The PRIA fails to account for the higher cost of spike testing for legacy pipe.[154] The logistics of spike testing will require a greater number of test sections on pipelines in locations with elevation changes. In a Subpart J hydrotest, a section in generally flat terrain may be addressed by a single test. In locations where there are changes in elevation, spike testing requires a greater number of test segments because only shorter segments of pipe can be tested effectively.[155] The increased number of test segments necessary for spike testing will greatly increase (double or even triple) the cost of spike testing far above the costs outlined in the PRIA tables. The cost of a hydrostatic test is largely a function of mobilization, equipment costs, labor, and demobilization costs. Doubling the number of sections effectively doubles the cost. A test

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[151] *Pub. Citizen v. FMCSA*, 374 F. 3d. 1209, 1216 (D.C. Cir. 2004) (finding that agency's failure to consider statutory factor constitutes a failure to consider an important aspect of the problem).

[152] PRIA at 34-36, 49-51, §§ 3.1.4.2, 3.1.5.2

[153] *See, e.g.*, PRIA at 36, § 3.1.4.2, Table 3-5.

[154] PRIA § 3.1.4.3

[155] The minimum spike testing level of 105% SMYS proposed by PHMSA will result in even more test sections. Operators generally do not want to exceed 110% SMYS as the maximum pressure in a test segment. This tight window of pressures will result in more test sections being required, not less.

section that would cost $750,000 to $1 million for a Subpart J test becomes $1.5 to 2 million for a spike test. Tripling the number of sections effectively triples the cost. The incremental costs of a spike test over a traditional subpart J hydrotest will provide no incremental safety improvement, because an adequate margin of safety already would be established by a subpart J hydrotest. The PRIA underestimates the costs of performing spike tests to reconfirm MAOP and, consequently, does not reflect accurately the additional costs of spike testing as compared to Subpart J pressure testing.

The PRIA also fails to account for the fact that there would be no incremental improvement in safety. Spike testing will likely result in more test failures because the pipe will be exposed to such high pressures (pressure levels that a pipe will never experience during its operations). Each failure will require an excavation to repair and retest the pipe segment. For example, in a test section that experienced three failures, the cost would be approximately $150,000 to $300,000 for just that segment of pipeline. An operator with legacy pipe could have tens and even hundreds of test sections that have similar number of failures. These increased repair costs are not accounted for in the PRIA sections 3.1.4 and 3.1.5.

Some INGAA members have tentatively reviewed portions of their systems where they might have MCAs and where they might need to reconfirm MAOP. This preliminary review indicates that approximately 50 percent of the MCA areas that will require MAOP reconfirmation are short, discontinuous segments approximately 1,000 feet long. The primary costs associated with pressure testing are mobilization related. Having to pressure test shorter sections of pipe in MCAs increases the testing costs dramatically. These costs would far exceed the costs outlined in the PRIA, which are based on longer test segments.

The PRIA completely overlooks the cost of FERC reservation charge credits. Under FERC policy, operators may incur an obligation to credit shippers for the reservation (demand) charges associated with the time that the pipeline was out of service for a pressure test. FERC requires all interstate pipelines to provide reservation charge credits to their firm shippers for outages of primary firm service attributable to circumstances within the pipeline's control, including planned or scheduled maintenance, as well as force majeure events.[156] With regard to spike testing, the need to test a greater number of shorter pipeline segments may result in the

[156] *See, e.g.*, *Tenn. Pipeline Co.*, Opinion No. 406, 76 FERC ¶ 61,022 (1996) (Opinion No. 406), *order on reh'g*, Opinion No. 406-A, 80 FERC ¶ 61,070 (1997) (Opinion No. 406-A), *as clarified by*, *Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272, at P 63 (2006) (*Rockies Express I*). *See also Algonquin Gas Transmission, LLC*, Order on Rehearing and Compliance Filing, 153 FERC ¶ 61,038, at P 2 (2015). Partial credits may be provided pursuant to: (1) the No-Profit method under which the pipeline gives credits equal to its return on equity and income taxes starting on Day 1; or (2) the Safe Harbor method under which the pipeline provides full credits after a short grace period when no credit is due (i.e. 10 days or less).

pipeline being out of service longer than would occur with Subpart J testing, resulting in a corresponding potential increase in reservation charge credits.[157]

Pipeline customers, such as industrial users, local gas utilities, gas-fired power generators, and marketers, which rely on pipelines to transport their gas, will be subject to service disruptions while the pipeline is out of service. These customers would have to seek alternative service or fuel sources, if possible, or potentially forego the ability to manufacture goods and services, produce electricity, or heat homes and businesses. These economic impacts are also not addressed in the PRIA.

The PRIA underestimates the environmental impacts of MAOP verification. INGAA expects that the increased use of spike and hydrostatic tests will cause increased landowner disturbance. Spike and hydrostatic tests also will cause an increase in environmental impacts associated with air emissions, ground disturbances, and effects to other environmental resources. Each time a test section is removed from service to conduct a spike or hydrostatic test; the pipeline segment must be blown down and filled with water to conduct the test. There are also ground disturbances related to mobilization of equipment and use of temporary workspaces. Finally, there are water uptake and discharge activities. Water uptake typically involves utilizing surface, municipal, or ground water resources. In certain areas, and in times of drought, water uptake may be limited or prohibited. After the test, the water is typically discharged onto land or into surface water, or the water is hauled off for disposal.

The PRIA vastly underestimates the greenhouse gas (GHG) emissions, compliance related costs, and the social cost of carbon of the proposal. *See* Section XVI.

PHMSA can ensure that more segments will be tested using ILI by removing the burdensome pre-approval process for using ILI for MAOP reconfirmation and by modifying the ECA process to remove the integrity management provisions. These changes would result in significantly lower emissions, less environmental impacts associated with water uptake, disposal and land disturbance, fewer reservation charge credits and less impact on shippers and consumers of natural gas.

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[157] FERC must authorize any relief to provide full reservation charge credits for any outages of primary firm service resulting from the NPRM. *See, e.g., Gulf S. Pipeline Co., LP*, 141 FERC ¶ 61,224, P 47 (2012)¸ *order on reh'g*, 144 FERC ¶ 61,215 (2013) ("The Commission is aware of the possible impact of the 2011 Act and PHMSA rulemakings and will closely monitor the implementation of the new requirements. The Commission is tracking the impacts of the 2011 Act and understands the importance of these issues and will consider the need for further action as the impact of PHMSA's implementation process moves forward.") (citing *CenterPoint Energy-Mississippi River Transmission, LLC,* 140 FERC ¶ 61,253, at P 65 (2012))

H. The Final Rule Should Clarify That Compliance With Any of the Six Methods to Reconfirm MAOP Satisfies the § 192.619 Requirement to Have an RTVC Pressure Test Record.

Under proposed § 192.624(c), operators have a choice of six methods to reconfirm MAOP for the specified areas. One of the triggers to reconfirm MAOP under § 192.624(a)(2) is the failure to have RTVC records of a pressure test under § 192.619(a)(1), (2), and (3). NPRM at 20,834. If an operator reconfirms MAOP using a method other than pressure testing, it may never have a pressure test to meet the requirements of §192.619(a)(1), (2), and (3). INGAA requests that PHMSA clarify in the final rule that once an operator has reconfirmed MAOP using any one of the six methods under § 192.624, then there are no further obligations under § 192.619(a)(1), (2) and (3).

I. Any Pressure Test to Subpart J Test Levels Should Be TVC Regardless of the Test Date.

The basic strength properties of steel pipe – yield strength, tensile strength, elongation, strain hardening, etc. – do not change with time. INGAA sees no basis for limiting allowable tests to only those conducted after July 1, 1965. A pressure test with TVC documentation should be regarded as a valid and compelling test regardless of whether it was conducted in June or July of 1965, in 1960 or at any other time. The test parameters, not the test date, should be considered for the establishment of MAOP. INGAA emphasizes that recognition of the validity of earlier tests for MAOP establishment or confirmation does not necessarily mean that no further pressure tests will be conducted. An additional test or periodic testing may be required to ensure the continued integrity of the segment under the operator's integrity management program. The safety margin provided by the Subpart J test or Subpart J test levels, regardless of when the pipe was manufactured, is adequate for establishing MAOP.

VIII. Material Verification (§ 192.607)

Proposed section § 192.607 would require operators of transmission lines located in HCAs or Class 3 or 4 locations for which RTVC documentation is insufficient to prepare a material documentation plan and conduct verification of material properties through a mixture of destructive and non-destructive tests whenever a pipe segment is exposed. NPRM at 20,831.

INGAA agrees that pipeline material data verification is important for MAOP reconfirmation in HCAs and Class 3 and Class 4 locations. INGAA disagrees with PHMSA's proposal to require operators to verify the physical and operational characteristics of the pipeline during *every* opportunistic dig. Not all of the requested data is necessary for MAOP reconfirmation of the pipeline or even for integrity-related activities. For instance, yield strength, ultimate tensile strength, chemical composition, coating type, and manufacturing specifications are not necessary to verify MAOP or operational characteristics for line pipe and fittings. Not all digs require an operator to reduce pressure or take the pipeline out of service and blowdown gas. Requiring an operator to do so in every instance would result in greater service interruptions than otherwise would occur.

Some of the proposed data would be unnecessary and irrelevant to achieving any safety benefits. There is no evidence that many of the requirements outlined in the NPRM will result in increased safety. In some instances, PHMSA's proposal could decrease safety by unnecessarily disturbing pipeline coating and increasing the risk of external corrosion through the proposed sampling process. There is also no evidence that the new material verification requirements will result in cost savings as claimed in the PRIA. The NPRM contains no analysis of the factors specified in the PSA that PHMSA must consider when adopting safety standards.[158]

INGAA proposes targeted changes to § 192.607 to require data acquisition only when that data is necessary for MAOP reconfirmation or as a part of work required by other provisions of Part 192.

A. PHMSA Has Not Adequately Justified How Its Proposal for Material Verification Improves Pipeline Safety.

Proposed § 192.607 would require operators to develop comprehensive material documentation plans within 180 days of the effective date of the final rule to verify that records of material properties for line pipe, valves, flanges, and components are "reliable, traceable, verifiable, and complete" for onshore steel gas transmission lines located in Class 3 or Class 4 locations or HCAs. The NPRM specifies the material information that must be validated. NPRM

[158] 49 U.S.C. § 60102(b).

at 20,831-32.

PHMSA states that § 192.607 implements section 23 of the 2011 Act which directed the agency to require owners and operators of gas transmission lines in Class 3 and 4 locations and Class 1 and 2 HCAs to verify that their records accurately reflect the physical and operational characteristics of pipeline and confirm the established MAOP.[159] Under the NPRM, an operator would be required to verify that records document the following information for line pipe and fittings: diameter, wall thickness, grade (yield strength and ultimate tensile strength), chemical composition, seam type, coating type, and manufacturing specification.

PHMSA states in the NPRM that additional rules are needed to implement section 23 of the 2011 Act because the information that operators submitted in their 2012 Annual Reports indicated that some transmission line segments lack "adequate records to establish MAOP or to accurately reflect the physical and operational characteristics of [their] pipeline[s]." NPRM at 20,812. PHMSA's basis does not adequately justify all of the proposed regulatory language. Operators are not required to submit information regarding the physical and operational characteristics of their pipelines in the Annual Reports. PHMSA's reliance on the information submitted by operators in their 2012 Annual Reports does not reflect a "rational connection" to the scope of the material attributes that PHMSA is proposing to require in this NPRM.[160]

PHMSA states further that it determined "that additional rules are needed to require that operators conduct tests and other actions needed to understand the physical and operational characteristics for those segments where adequate records are not available, and to establish standards for performing these actions." NPRM at 20,812. Citing the August 7, 2013 IVP Workshop, PHMSA stated that the most difficult information for an operator to obtain is strength of the steel because it requires cutting out a piece of pipe and destructively testing it to determine yield and ultimate tensile strength (UTS). NPRM at 20,812. PHMSA does not explain why ultimate tensile strength of steel is relevant and should be required for either MAOP reconfirmation or operations, maintenance or integrity tasks. PHMSA also does not provide a technical justification for the other data required by proposed § 192.607, such as chemical composition of the pipe and manufacturing specifications. PHMSA also does not explain why requiring such information is practicable and designed to meet safety needs and protect the environment.[161] PHMSA misinterpreted comments INGAA filed in the IVP proceeding regarding how information about specific material properties is used in operation, maintenance

[159] Section 23 of 2011 Act, codified at 49 U.S.C. § 60139. Other NPRM provisions would require that operators of transmission pipelines acquire and maintain records documenting (1) original steel pipe manufacturing information (§ 192.67), (2) pipe design information (§ 192.127), and (3) manufacturing standard and pressure ratings for pipeline components (§ 192.205). These provisions are not limited to lines lacking adequate material documentation records located in Class 3 or Class 4 locations or HCAs, and consequently, would apply more broadly than § 192.607.

[160] *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F. 3d 831, 839, 843 (D.C. Cir. 2006).

[161] 49 U.S.C. § 60102(b)(1).

and integrity-related activities. Some of the data that PHMSA proposes to require operators to validate is unnecessary and will not enhance overall pipeline safety.[162]

B. PHMSA Should Extend the Timeframe to Complete a Material Verification Plan to One Year From the Effective Date of the Final Rule.

INGAA recommends that PHMSA extend the proposed six-month timeframe for operators to complete a material documentation plan. The NPRM proposes that an operator must assess its system and put together a plan to verify material properties of its pipes where RTVC records are not available.[163] PHMSA proposes that an operator must prepare this plan demonstrating how it would implement all actions proposed in § 192.607(d) within 180 days of the effective date of the final rule. This timeframe is not practical or reasonable when one considers the steps necessary to complete such a plan. Steps associated with the material verification plan would include:

1) Identification and determination of data sources for all pipeline materials in HCAs and Class 3 and 4 locations with insufficient TVC documentation. This step alone is time-consuming because it involves locating records both onsite and offsite. The type and location of the records are unique to each pipeline asset based on historical record keeping practices. A significant amount of subject matter expert's time will be required to review and evaluate the sufficiency of the records once they are located.
2) Strategic prioritization and scheduling of pipeline materials to be verified. This single step involves consideration of many factors including, history of the pipeline, risk, population density, etc.. This step alone could take six months to complete.
3) Development of procedures for destructive and nondestructive testing of pipeline materials.
4) Documentation of test results.
5) Updating records and databases.

Given the amount of work necessary to prepare a plan and the time needed to complete each step, PHMSA should allow operators one year from the effective date of the final rule to develop a material documentation plan.

C. Some of the Data PHMSA Proposes that Operators Verify Is Unnecessary For MAOP Verification or Other Operational Reasons.

INGAA proposes that the data acquired and maintained meet the requirements of the work being conducted. Several of the data elements that would need to be verified pursuant to § 192.607 unnecessary for verification of MAOP or for other operations, maintenance or

[162] Additional Comments of INGAA on the PHMSA Draft Integrity Verification Process, Docket No. PHMSA-2013-0119 at 15 (Oct. 7, 2013).
[163] 49 C.F.R. § 192.607(b).

integrity-related activities. Safety would not be improved by collecting some of the data that would be required by the NPRM. Table X shows which material properties data are used in verifying MAOP or in conducting operations, maintenance and integrity-related work.

Table A – Material Properties Used in Verifying MAOP Or Conducting Operations, Maintenance, and Integrity Related Activities

Data To Be Acquired and Maintained	Needed for MAOP Reconfirmation?	Needed for Operations?	Needed for Maintenance?	Needed for Integrity – General?	Needed for Integrity - Metal Loss?	Needed for Integrity – Cracks?
Diameter	Yes	Yes	Yes	Yes	Yes	Yes
Wall Thickness	Yes	Yes	Yes	Yes	Yes	Yes
Grade (1)	Yes	Yes	Yes	Yes	Yes	Yes
Yield Strength (1)	No	No	No	No	No	No
Ultimate Tensile Strength	No	No	No	No	No	No
Chemical Composition	No	No	No [2]	No [2]	No	No
Manufacturing Specification	No[3]	No	No[3]	No[3]	No	No
Seam Type/ Longitudinal Seam Factor (4)	Yes	Yes	No	No	Yes	Yes
Coating	No	No	No	Yes	No	No
Toughness (Charpy v-Notch)	No	No	Yes	No	No	Yes
Weld End Bevel Condition	No	No	No[5]	No	No	No

1. If grade is unknown, yield strength can be used; both are not required. Grade is the conventional method to represent yield strength in calculated MAOP. 49 CFR 192.105. If grade is unknown then yield strength can be determined using non-destructive or destructive methods.
2. Chemical composition can be deduced based on historical attributes of pipe.
3. Can be used as complimentary record to deduce seam type.
4. Seam type can be deduced from historical documents such as the ASME History of Line Pipe Manufacturing—CRTD 43.
5. Weld end bevel condition is inspected by qualified welders to ensure proper alignment and tolerances in conformance with applicable referenced API, ASME, and Manufacturers Standardization Society Specifications (MSS) standards. Even where records are available, welders inspect valves and fittings on site and may adjust the bevel(s) prior to commencing welding activities.

As demonstrated by the table, diameter, wall thickness, grade, and seam type are necessary for MAOP reconfirmation, operation, maintenance or integrity-related activities. Chemical composition, coating type, manufacturing specification, toughness using a Charpy v-notch test, weld end bevel condition, and ultimate tensile strength are not necessary.

Operators do not need to know the exact Charpy v-notch toughness values at every location of the pipeline. NPRM at 20,831. By knowing the pipe grade, operators apply conservative toughness assumptions[164] and have successfully applied this approach on gas pipelines for years. Charpy v-notch toughness is used only in two identified circumstances: (1) Knowing the toughness with greater certainty is important for pipelines operating in a fatigue environment, which is generally not a concern for gas pipelines; and (2) Crack analysis and management. Given these limited applications, there is no technical justification for PHMSA to require blanket collection of this data which can be collected only through destructive testing.

There also is no basis for PHMSA to require an operator to acquire records on weld end bevel conditions at each excavation. This information is important only when welding a replacement pipe on a particular fitting. Where records do not show the weld end bevel condition, an operator will review the rating of the fitting and measure it before the actual work is performed. Qualified welders inspect weld end bevel conditions on pipe segments prior to welding to ensure proper alignment and tolerances in accordance with API, ASME and company standards. For example, ASME B31.8[165] defines allowable offset and the means to ensure proper transitions to maintain strength. Records might be available for weld end bevel conditions for valves but those are still inspected on-site prior to commencing welding activities. Qualified technicians typically take ultrasonic technology measurements and evaluate offset and possible fit up issues. During the public webinar on June 29, 2016, PHMSA was unable to explain why weld end bevel condition is required in § 192.607. There is no basis to require operators to collect this information for each excavation.

Ultimate tensile strength and chemical composition are not used alone in any of the work defined in Table A. Where yield is unknown, UTS is sometimes used as an alternative in combination with chemical composition to estimate grade. This methodology is used by operators only when there is no other option. There is no basis for PHMSA to require acquisition of chemical composition and UTS at each excavation when such information is not always needed. An operator can estimate grade by knowing yield strength in most instances without knowing UTS.

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[164] Riccardella, Peter, Structural Integrity Associates, Inc., Statistical Evaluation of Charpy Toughness Levels for Gas Transmission Pipelines, Report No. 1600513.401 (July 5, 2016).

[165] *See* ASME B31.8-2007, Gas Transmission and Distribution Piping Systems, Code for Pressure Piping at 152, Appendix I.

PHMSA should remove pipeline coating type from the list of required data in § 192.607. An operator tries not to disturb the pipe coating during excavation, if possible, so as not to increase the risk of external corrosion. PHMSA acknowledges the importance of not disturbing coating in existing regulation § 192.461(e) which provides that "[i]f coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation." Pipeline coating type is, in practice, determined through visual examination every time the pipeline is inspected under § 192.459. Operators, as a general practice, already determine the type of coating as part of the determination of the condition of coating under § 192.459. It is not necessary to include pipeline coating type in § 192.607.

As detailed in INGAA's proposed rule text below, the following six data requirements should be removed from § 192.607 because they are not typically required for maintaining pipeline integrity: ultimate tensile strength, chemical composition, manufacturing specifications, toughness using a Charpy v-notch test, coating type, and weld end bevel condition. Rather than requiring an operator to obtain this information at every excavation, PHMSA should provide that operators identify in their material documentation plans the specific circumstances in which this data must be obtained.

D. PHMSA Should Allow Operators to Acquire and Maintain Pipeline Materials When Operators Are Conducting Work Already Required Under Part 192 Instead of During Each and Every Excavation.

PHMSA should allow operators to collect the data required by § 192.607 on an ongoing basis, as needed, rather than during each excavation as would be required in proposed § 192.607. Destructive and non-destructive testing should only be required if the operator is performing these kinds of tests for other reasons, such as for repair of an anomaly identified during an ILI. The language in proposed § 192.607(d)(3) particularly "or any other reason for which the pipe segment is exposed" is too broad. NPRM at 20,831. The prescribed number of digs in § 192.607(d)(3)(ii) (150 excavations or one per mile) should also be removed as it is overly burdensome and there is no technical basis for this random number. PHMSA should require operators to obtain the specific physical and operational information when it is needed for a specific purpose, but it should not require wholesale collection of this information during each excavation when it does not provide additional safety benefits.

E. PHMSA Has Failed to Evaluate the Impacts and Costs of the Required Testing and Data Collection.

Data collection has a cost, even when conducted during other work that exposes the pipe. If PHMSA chooses to require that destructive and non-destructive tests be performed for each excavation where the tests would not otherwise be performed, then PHMSA must account for the costs of those tests. Contrary to the assertion in § 4.1.2.3 of the PRIA, operators are not required to cut out every tenth section of pipe under § 192.107(b). Section 192.107(b) and Appendix B, Section D-II are design regulations and do not create ongoing obligations for in-service pipelines.[166] Rather, operators use a conservative assumption of the yield strength, such as assuming 24,000 p.s.i. as allowed by § 192.107(b)(2). There is no basis for the notion that the material verification requirements in proposed § 192.607 will result in a cost savings. If these requirements remain for all excavations, PHMSA must include the costs of these additional tests, both destructive and non-destructive.[167]

F. PHMSA Should Revise the Requirements for Destructive and Non-Destructive Testing.

PHMSA has already incorporated API Spec 5L in the pipeline safety regulations.[168] This specification describes the locations and methods for destructive testing. Rather than introducing new requirements, PHMSA should reference API Spec 5L for destructive testing in § 192.607. For non-destructive testing, there are currently no industry standards since these technologies have been commercialized only recently. Several service providers are working on the validation of their methods jointly with PHMSA. The agency should allow operators to use the specification of the subject-matter expert performing the non-destructive test until an industry standard has been developed.

G. Use of Alternative Technology

INGAA recommends that PHMSA remove § 192.607(d)(6). ILI and other technology should be allowed in accordance with the operator's material documentation plan without requiring an operator to follow a pre-notification and approval process.

H. INGAA's Proposed Regulatory Text Relating to Material Verification.

§ 192.607 Verification of Pipeline Material: Onshore steel transmission pipelines.

(a) ***Applicable locations.*** Each operator must follow the requirements of paragraphs (b) through (d) of this section for each segment of onshore, steel, gas transmission pipeline installed before ***[insert the effective date of the rule]*** that does not have ~~reliable,~~ traceable, verifiable, and complete material documentation records for line pipe, valves, flanges, and components and meets any of the following conditions:

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[166] Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standards, 35 Fed. Reg. 13,248, 13,250 (Aug. 19, 1970); *see In the Matter of Belle Fourche Pipeline Co., Decision on Reconsideration*, CPF No. 5-2004-5010, 2009 WL 7810536, at *4 (D.O.T. Jul. 15, 2009); Letter from Richard L. Beam, Associate Director for Office of Pipeline Safety Regulations, Materials Transportation Bureau, to Mr. Alfred V. Colabella, Jr., PE (Nov. 7, 1984); Letter from Richard L. Beam, Associate Director for Office of Pipeline Safety Regulations, Materials Transportation Bureau, to Mr. Alfred V. Colabella, Jr., PE (Nov. 19, 1984); Operating Pressure for Platform Piping; Interpretation, Department of Transportation, Materials Transportation Bureau, Docket No. OPSO-35 (Oct. 15, 1976).

[167] PRIA at 122-123, § 4.1.2.3 and Table 4-6.

[168] 49 C.F.R. § 192.7(b).

(1) The pipeline is located in a High Consequence Area as defined in § 192.903*;* or

(2) The pipeline is located in a class 3 or class 4 location

(b) ***Material documentation plan.*** Each operator must prepare a material documentation plan to implement all actions required by this section by ***[date ~~180 days~~ one year after the effective date of the final rule].***

(c) ***Material documentation.*** Each operator must have ~~reliable,~~ traceable, verifiable, and complete records documenting the following:

(1) For line pipe and fittings, records must document diameter, wall thickness, grade ~~(yield strength and ultimate tensile strength), chemical composition,~~ and seam type, ~~coating type, and manufacturing specification.~~

(2) For valves, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating. ~~For valves with pipe weld ends, records must document the valve material grade and weld end bevel condition to ensure compatibility with pipe end conditions;~~

(3) For flanges, records must document either the applicable standards to which the component was manufactured, the manufacturing rating, or the pressure rating~~, and the material grade and weld end bevel condition to ensure compatibility with pipe end conditions~~;

(4) For components, records must document the applicable standards to which the component was manufactured to ensure pressure rating compatibility;

(d) ***Verification of material properties***. For any material documentation records for line pipe, valves, flanges, and components specified in paragraph (c) of this section that are required to conduct work under Subparts I, K, L, M, and O and are not available, the operator must take the following actions to determine and verify the physical characteristics.

(1) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for line pipe at all above ground locations.

(2) Develop and implement procedures for conducting destructive tests, examinations, and assessments for buried line pipe at all excavations associated with replacements or relocations of pipe segments that are removed from service.

(3) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for buried line pipe at all excavations associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, or ~~any other reason for which the pipe segment is exposed~~, except for segments exposed during excavation activities that are in compliance with § 192.614~~, until completion of the minimum number of excavations as follows.~~

~~(i) The operator must define a separate population of undocumented or inadequately documented pipeline segments for each unique combination of the following attributes: wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe manufacturing dates (within a two year interval) and construction dates (within a two year interval).~~

~~(ii) Assessments must be proportionally spaced throughout the pipeline segment. Each length of the pipeline segment equal to 10 percent of the total length must contain 10 percent of the total number of required excavations, e.g. a 200 mile population would require 15 excavations for each 20 miles. For each population defined according to (i) above, the minimum number of excavations at which line pipe must be tested to verify pipeline material properties is the lesser of the following:~~

~~(A) 150 excavations; or~~

~~(B) If the segment is less than 150 miles, a number of excavations equal to the population's pipeline mileage (i.e., one set of properties per mile), rounded up to the nearest whole number. The mileage for this calculation is the cumulative mileage of pipeline segments in the population without reliable, traceable, verifiable, and complete material documentation.~~

(i~~ii~~). At each excavation, where pipe is removed tests for material properties must determine diameter, wall thickness, yield strength, ~~ultimate tensile strength, Charpy v-notch toughness (where required for failure pressure and crack growth analysis), chemical properties,~~ seam type, coating type, and must test for the presence of stress corrosion cracking, seam cracking, or selective seam weld corrosion using ultrasonic inspection, magnetic particle, liquid penetrant, or other appropriate non-destructive examination techniques. Determination of material property values must conservatively account for measurement inaccuracy and uncertainty based upon comparison with destructive test results using unity charts.

~~(iv) If non-destructive tests are performed to determine strength or chemical composition, the operator must use methods, tools, procedures, and techniques that have been independently validated by subject matter experts in metallurgy and fracture mechanics to produce results that are accurate within 10% of the actual value with 95% confidence for strength values, within 25% of the actual value with 85% confidence for carbon percentage and within 20% of the actual value with 90% confidence for manganese, chromium, molybdenum, and vanadium percentage for the grade of steel being tested.~~

(~~v~~) ~~The minimum number of test locations at each excavation or above ground location is based on the number of joints of line pipe exposed, as follows:~~

~~(A) 10 joints or less: one set of tests for each joint.~~

~~(B) 11 to 100 joints: one set of tests for each five joints, but not less than 10 sets of tests.~~

~~(C) Over 100 joints: one set of tests for each 10 joints, but not less than 20 sets of tests.~~

(~~v~~ii) For non-destructive tests, at each test location, a set of material properties tests must be conducted in accordance with operator or service provider specifications ~~at a minimum of five places in each circumferential quadrant of the pipe for a minimum total of 20 test readings at each pipe cylinder location.~~

(~~v~~iii) For destructive tests, at each test location, a set of materials properties tests must be conducted in accordance with the original manufacturing specification, if known, such as API Spec 5L ~~on each circumferential quadrant of a test pipe cylinder removed from each location, for a minimum total of four tests at each location~~.

~~(viii) If the results of all tests conducted in accordance with paragraphs (i) and (ii) verify that material properties are consistent with all available information for each population, then no additional excavations are necessary. However, if the test results identify line pipe with properties that are not consistent with existing expectations based on all available information for each population, then the operator must perform tests at additional excavations. The minimum number of excavations that must be tested depends on the number of inconsistencies~~

~~observed between as found tests and available operator records, in accordance with the table below:~~

~~Number of Excavations With Inconsistency Between Test Results and Existing Expectations Based on All Available Information for each Population~~	~~Minimum Number of Total Required Excavations for Population. The lesser of:~~
~~0~~	~~150 (or pipeline mileage)~~
~~1~~	~~225 (or pipeline mileage times 1.5)~~
~~2~~	~~300 (or pipeline mileage times 2)~~
~~>2~~	~~350 (or pipeline mileage times 2.3)~~

~~(ix) The tests conducted for a single excavation according to the requirements of § 192.607(d)(3)(iii) through (vii) above count as one sample under the sampling requirements of § 192.607(d)(3)(i), (ii), and (viii).~~

(4) For mainline pipeline components other than line pipe, the operator must develop and implement procedures for establishing and documenting the ANSI rating, where applicable, and material grade (to assure compatibility with pipe ends).

(i) Materials in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, operator piping, or cross-connections with isolation valves from the mainline pipeline are not required to be tested for chemical and mechanical properties.

(ii) Verification of mainline material properties is required for non-line pipe components, including but not limited to, valves, flanges, fittings, fabricated assemblies, and other pressure retaining components appurtenances that are:

(A) Larger than 2-inch nominal diameter ~~and larger~~, or

(B) Material grades greater than 42,000 psi (X-42), or

(C) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

(iii) Procedures for establishing material properties for non-line pipe components where records are inadequate must be based upon documented manufacturing specifications. Where specifications are not known, usage of manufacturer's stamped or tagged material pressure ratings and material type may be used to establish pressure rating. The operator must document the basis of the material properties established using such procedures.

(5) The material properties determined from the destructive or non-destructive tests required by this section cannot be used to raise the original grade or specification of the material, which must be based upon the applicable standard referenced in § 192.7.

~~(6) If conditions make material verification by the above methods impracticable or if the operator chooses to use "other technology" or "new technology" (alternative technical evaluation process plan), the operator must notify PHMSA at least 180 days in advance of use in accordance with paragraph § 192.624(e) of this section. The operator must submit the alternative technical evaluation process plan to the Associate Administrator of Pipeline Safety with the notification and must obtain a "no objection letter" from the Associate Administrator of Pipeline Safety prior to usage of an alternative evaluation process.~~

IX. Pipeline Assessments (§ 192.710) and Remediation Schedule (§§ 192.713 and 192.933)

A. PHMSA Should Define "Instrumented Inline Inspection Segment."

Several provisions in the NPRM, including § 192.710, Pipeline Assessments, refer to pipe segments that "[can] accommodate the passage of instrumented internal inspection devices," "capable of inspection by internal inspection tools," or "[can] accommodate inspection by means of instrumented inline inspection tools (*i.e.*, "smart pigs.")"[169] PHMSA does not define or explain the criteria that make a segment capable of inspection by internal inspection tools.

PHMSA should define "instrumented inline inspection segments" and define the term in § 192.3. Operators with pipeline segments that can "accommodate" an instrumented inline inspection tool may not be able to use all types of instrumented inline inspection tools due to sizing and operating condition limits of the pipe segment. Under existing technology, if an operator wishes to use an ILI tool to reconfirm MAOP in an MCA operating over 30% SMYS, the operator would need to use a free-swimming EMAT tool. If an operator cannot run an EMAT tool in that segment, due to the size or operating condition of the segment, the segment would not be able to "accommodate" an inline inspection tool and would not be an MCA covered under § 192.624.

Even if a pipe segment is capable of accommodating a tool for one purpose, the same tool may not be sophisticated enough to transmit relevant, interpretable data for another purpose. For example, a tool that is capable of assessing external corrosion (e.g., with an axial MFL tool) under § 192.710 is not capable of identifying original manufacturing-related cracking under § 192.624. The tool must be "capable of assessing the identified threat(s)" that the operator is trying to evaluate.

PHMSA also should clarify that "an instrumented inline inspection segment" is one in which a free-swimming tool can travel and record and transmit relevant, interpretable inspection data. Not all ILI tools provide an operator with the necessary level of data required to reconfirm MAOP. As ILI technology advances and commercial availability improves, a greater number of pipeline segments will be capable of assessment. INGAA expects that ILI service providers will meet the challenge of developing and enhancing tool capabilities to "accommodate" greater ranges of multi-diameter pipe and address low flow scenarios. INGAA proposes to add the following definition of the term "instrumented inline inspection segment" to § 192.3:

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[169] Proposed §§ 192.150(a), 192.624(a)(1)(iii), 192.624(a)(3)(iii), 192.710(c)(6), 192.921(a)(6), and 192.937(c)(6).

An instrumented inline inspection segment means a length of pipeline through which a free-swimming commercially available in-line inspection tool can travel without the need for any permanent physical modifications to the pipeline and (1) is capable of assessing the identified threat(s); (2) can inspect the entire circumference of the pipe; and (3) can record or transmit relevant, interpretable inspection data.

B. PHMSA Should Revise § 192.710(c)(4) to Allow Operators Perform a Direct Examination Using the Best Technique(s).

In § 192.710(c)(4), PHMSA proposes to require operators performing direct examinations to use ultrasonic testing, radiography, and magnetic particle inspection to collect data. Operators do not typically use all three types of inspection techniques to perform a single direct examination. Ultrasonic testing and radiography may be redundant inspection techniques and both should not be required. Radiography, for example, may be appropriate in certain limited circumstances such as weld inspection, but may be irrelevant for most other assessments. PHMSA should allow operators to determine the best technique to assess the integrity of the pipeline and its proposed regulation should be revised to clarify that these are not additive requirements. PHMSA offers this kind of flexibility to operators in HCAs[170] and there is no reason it should not be offered to operators in non-HCAs as well.

C. INGAA's Proposed Regulatory Text Relating to Pipeline Assessments

§ 192.710 Pipeline assessments.

[…]

(c) Assessment method.

[…]

(4) Excavation and *in situ* direct examination by means of visual examination and direct measurement and recorded non-destructive examination results and data needed to assess all threats, including but not limited to, ultrasonic testing (UT), radiography, and magnetic particle inspection (MPI) to collect data, as applicable…

D. PHMSA Should Allow SCCDA.

In three different sections of the NPRM, PHMSA proposes to modify when Stress Corrosion Cracking Direct Assessment (SCCDA) can be used. Sections 192.710(c)(6), 192.921(a)(6), and 192.937(c)(6) contain the same language that:

[170] *See* PHMSA Gas Integrity Management, FAQ-277 (Sept. 8, 2011), http://primis.phmsa.dot.gov/gasimp/faqs.htm; *See also* Inspection Protocol, D.04 ECDA Direct Examination.

> Use of direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the methods specified in paragraphs (d)(1) through (5) of this section.

As written, this regulatory text is too prescriptive and essentially eliminates the use of SCCDA even for situations where it is proven effective. As recognized by PHMSA in proposed § 192.929 with the adoption of NACE SP0204-2008, SCCDA is a valid way to assess for SCC threat in gas pipelines when the basic criteria for SCC has been met per ASME B31.8S and there is no history of SCC on the pipeline. When there is a history of SCC, an ILI or pressure spike test should be used. INGAA proposes that PHMSA modify §§ 710(c)(6), 921(a)(6), and 937(c)(6) to read:

§ 192.710 Pipeline assessments.

[…]

(c) Assessment method.

[…]

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of external corrosion direct assessment and internal corrosion direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the methods specified in paragraphs (d)(1) through (5) of this section. An operator must conduct the Direct Assessment in accordance with the requirements specified in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927, or 192.929. The same restriction applies to SCCDA only if stress corrosion cracking has been found on like- pipe in that pipeline segment; or…

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of line pipe in each covered segment by applying one or more of the following methods depending on the for each threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917). In addition, an operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

[…]

(6~~3~~) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of external corrosion direct assessment and internal corrosion direct assessment is allowed only if the line is not capable inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with, as the applicable, the requirements specified in §§ 192.925, 192.927 or 192.929; or

§ 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, a~~An operator must assess the integrity of the line in ~~the~~each covered segment by applying one or more~~any~~ of the following methods for each threat ~~as appropriate for the threats~~ to which the covered segment is susceptible. ~~(*See* § 192.917), or by confirmatory direct assessment under the conditions specified in § 192.931.~~ The operator must select the method or method best suited to address the threats identified to the covered segment (*See* § 192.917). An operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

[…]

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of external corrosion direct assessment and internal corrosion direct assessment is allowed only if the line is not capable of inspection by internal inspection tools and is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the methods specified in paragraphs (d)(1) through (5) of this

section. The same restriction applies to SCCDA only if stress corrosion cracking has been found on like- pipe in that pipeline segment

E. Permanent Field Repair of Imperfections and Damages

PHMSA proposes to modify § 192.933 and modify § 192.713, which tracks the repair criteria of modified § 192.933. These proposed changes establish the requirements for responding to anomalies and performing permanent field repair of imperfections and damages.

PHMSA proposes to modify these requirements by adding a new applicability requirement in subsection (a) of § 192.713 and a new general duty clause in subsection (b) of § 192.713. PHMSA proposes moving the requirements in current § 192.713(a) into subsection (c) of § 192.713. In addition, PHMSA proposes to add a new schedule for remediating conditions on pipeline segments that are not located in HCAs in subsection (d) of § 192.713, similar to the requirements for HCAs in § 192.933(d); a general duty clause for remediating all other conditions in subsection (e) of § 192.713; and provisions for performing *in situ* examinations of crack defects in subsection (f) of § 192.713.

As a justification for the proposed changes, the NPRM states "PHMSA has determined that more explicit requirements are needed to better identify criteria for the severity of imperfection or damage that must be repaired, and to identify the timeframe within which repairs must be made." NPRM at 20,815. PHMSA further states that these new "criteria should apply to any transmission pipeline not covered under subpart O, Integrity Management regulations[,]" and that the "changes will ensure the prompt remediation of anomalous conditions, while allowing operators to allocate their resources to high consequence areas on a higher priority basis." NPRM at 20,815.

PHMSA has failed to satisfy the requirements of the PSA in proposing § 192.713's repair conditions. PHMSA has not explained how they are practicable, reasonable, or appropriate. PHMSA has not explained how they are designed to meet pipeline safety needs and protect the environment.[171] PHMSA also has failed to acknowledge important departures from longstanding practice.[172]

INGAA proposes that PHMSA separate the concepts of response, remediation, and repair and to specify immediate one/two-year and scheduled response conditions. PHMSA should allow operators to use the repair methods from ASME/ANSI B31.8S. PHMSA should make revisions to refer to response rather than repair or remediation. INGAA proposes that PHMSA modify the lists of immediate and one/two-year conditions so that they are consistent with well-

[171] 49 U.S.C. § 60102(b)(1) & (2).

[172] *Encino Motorcars, LLC, v. Navarro*, No. 15-415, 2016 WL 3369424, *7 (2016).

established, accepted, industry standards. INGAA proposes that PHMSA utilize the terms "metal loss" and "crack-like" features when referring to ILI results and "corrosion" and "cracking" when referring to in-field examinations. PHMSA should allow operators to determine a safe pressure when reducing operating pressure under § 192.713 consistent with requirements in § 192.933(a)(1) and § 192.485(c). PHMSA should delete certain superfluous and duplicative provisions in § 192.713 and § 192.933. These changes align the proposed provisions of § 192.713 with the existing provisions of § 192.933 and vice versa. INGAA's proposed changes are practicable, reasonable, appropriate, technically based, designed to meet pipeline safety needs, and to protect the environment.[173]

1. PHMSA Should Delete Proposed § 192.713(a) (Applicability) Because It Is Superfluous and Revise § 192.713(b)

PHMSA proposes to add a new applicability provision in § 192.713(a). The provision states that § 192.713 applies to all gas transmission lines, including those located in HCAs. INGAA requests that PHMSA delete its proposed § 192.713(a) since it is superfluous and adds no substantive requirements. PHMSA can address the applicability to all gas transmission lines in proposed § 192.713(b) without impacting PHMSA's intent of explaining which pipelines are covered. INGAA provides revised regulatory text of § 192.713 below. PHMSA should eliminate proposed § 192.713(a), revise § 192.713(b) to clarify that the regulation applies to each "transmission line operator," and renumber the § 192.713 subsections accordingly.

2. In § 192.713(c), PHMSA Should Allow Operators to Use the Repair Methods from ASME B31.8S.

PHMSA proposes to recodify the existing § 192.713(a) requirements for making permanent field repairs of imperfections without change as the new, proposed § 192.713(c):

> Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—
>
> (1) Removed by cutting out and replacing a cylindrical piece of pipe; or
>
> (2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

While INGAA supports maintaining the longstanding requirements for making permanent field repairs of imperfections and damages, PHMSA should allow operators to use the repair methods recognized in ASME B31.8S. Adding a reference to ASME B31.8S will result in greater consistency of repair methods, improve pipeline integrity, and increase public safety and

[173] 49 U.S.C. § 60102(b)

environmental protection. This change will improve PHMSA's proposed regulation. *See* INGAA's proposed regulation text.

3. PHMSA's Proposed §§ 192.713(d) and 192.933(d) Remediation Schedules Conflate Response, Remediation and Repair; Are Confusing; and if Left Unchanged, Would Require Operators to Make Unnecessary Repairs.

Under proposed modifications to § 192.933(d), PHMSA revises remediation requirements for conditions discovered on any gas transmission pipeline located inside of an HCA. PHMSA proposes to graft these proposed remediation requirements into proposed §§ 192.713(d)(1)-(4). Both current and proposed regulations do not recognize the important differences in what an operator does when evaluating the results of an integrity assessment and what an operator does when conducting an in-field examination of the pipeline. Proposed §§ 192.713(d) and 192.933(d) also do not accurately reflect the use of the term "remediation." INGAA requests that PHMSA retitle the section as "response" rather than remediation. The criteria in §§ 192.713(d) and 192.933(d) should be applied as response criteria, *i.e.*, when to schedule an in-field examination to evaluate the condition and remaining strength of the pipeline. Repairs are made using § 192.713(c) and after the operator has physically examined and evaluated the pipeline in the field.[174] Consistent with this, INGAA is proposing to add § 192.933(e). Clarification of response and repair is provided in the following discussion.

An integrity assessment provides information on conditions that may require further investigation. The actual characteristics of that condition, and whether it requires repair or remediation, cannot be established without the operator conducting a physical in-field examination (a "dig") and evaluating the results of that examination. In many cases, anomalies that appear to require "repair" based on initial indirect tool measurements, such as indications from an ILI report (*e.g.*, immediate conditions), do not require repair once the anomaly is excavated, physically examined, and then evaluated in the field. This is because assessment technologies, such as magnetic flux leakage (MFL) ILI tools use indirect measurements to infer conditions on the pipeline rather than directly measure them. The MFL ILI tool identifies areas to be investigated further through a direct in-field inspection of the pipeline. Because of the limitations of these ILI technologies compared to physical in-field examinations, the conditions that drive response to an anomaly are different than the conditions that would drive repair once the anomaly has been physically examined and evaluated. After an assessment, an operator follows a stepwise process to respond to its findings report, followed by an in-field inspection,

[174] This section of the comments is limited to the appropriate meaning and application of response, remediation and repair concepts. INGAA addresses the specifics of immediate, one-year, two-year, scheduled and monitored conditions in subsequent sections of these comments.

then based on the inspection results, takes appropriate action as depicted in Figure 2—Anomaly Response and Repair.

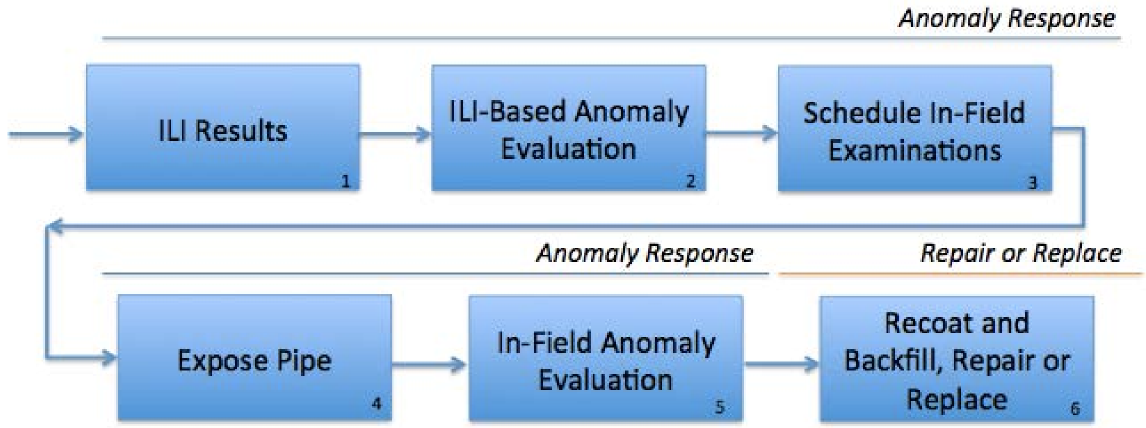

Figure 2—Anomaly Response and Repair.

The anomaly response and repair process begins with evaluation of the ILI results (step 1). The results are compared with response criteria (step 2) to determine what response is required. Step 2 entails applying remaining strength models (*e.g.*, ASME Mod B31G and Modified Ln Secant) to evaluate metal loss or crack-like features identified by the integrity assessment. Criteria in §§ 192.713(d)(1) and (3) and §§ 192.933(d)(1) and (2) should be applied as anomaly response criteria (not anomaly repair criteria, as proposed by PHMSA). An example of a response criterion is that an anomaly whose remaining strength is less than 1.1 x MAOP is an immediate condition. Once the operator has identified this condition, it is scheduled (step 3) for an in-field examination. This work is scheduled based on indirect measurements of the ILI that indicate it is a condition requiring an immediate "response." A crew is scheduled and the pipe is exposed during an in-field examination (step 4). Once the pipe is exposed, and the surface prepared, the actual "as found" features identified by the integrity assessment can be examined and evaluated. The actual features are measured and measurements are used in the same remaining strength models (step 5). A decision to repair or replace is based on §192.713(c) or INGAA's proposed § 192.933(e) (step 6). To summarize, anomaly response is based on an evaluation of features using applicable remaining strength models to define a "response." The decision to repair or replace is made only after evaluating the actual as found conditions on the pipeline after the in-field examination.

4. Sections 192.713(d)(1) and 192.933(d)(1) – Response Criteria When Assessment Data Indicates an Immediate Condition.

PHMSA proposes modifications to the immediate repair conditions in § 192.933(d)(1) and proposes a new set of matching immediate repair conditions in §§ 192.713(d)(1)(i)–(vii). The prescriptive criteria that PHMSA is proposing as "repair conditions" do not always require a repair and should be treated as response criteria, *i.e.*, criteria used to schedule in-field examinations, as discussed above. They are not conditions requiring repair until they are examined in the field. These conditions can be evaluated and managed using sound engineering analysis and can be categorized for response accordingly. Requiring a repair where the serviceability of the pipe is not compromised is inconsistent with current code approach. For example, § 192.485 states:

> the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, see §192.7) or the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, *see* §192.7). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

This provision contemplates that, before performing a repair, an operator first responds by evaluating the affected area of the pipe to determine appropriate repair, if any, that is required. Applying PHMSA's proposed prescriptive criteria would eliminate this step and result in unnecessary use of resources to excavate, investigate and repair anomalies that do not compromise public safety. Requiring such repairs would increase the risk to those performing the work on in service gas transmission pipelines, the public located around the pipeline, and the environment. Because PHMSA's proposed approach would result in an increased risk to public safety with no associated improvement in pipeline integrity, INGAA proposes that PHMSA revise §§ 192.713(d)(1) and (3) specifying immediate, two-year, and scheduled response conditions. INGAA also proposes that PHMSA revise §§ 192.933(d)(1) and (2) specifying immediate, one-year, and scheduled response conditions.

PHMSA has not explained how it determined its proposed immediate repair conditions. Nor has it provided supporting technical data or information demonstrating that its criteria and the proposed immediate repair requirements are related to actual risks posed by those conditions. PHMSA has not shown, for example, how a dent with metal loss due to corrosion requires an immediate repair due to immediate safety concerns. PHMSA has failed to satisfy the requirement of the PSA in the proposed repair conditions in §§ 192.713 and 192.933. PHMSA has not explained how they are practicable, reasonable, appropriate, or are designed to meet pipeline safety needs or protect the environment.[175] In contrast, Section 7 of ASME B31.8S identifies conditions that would trigger various operator responses based on an assessment of the actual risks posed by different types of conditions. The ASME B31.8S criteria have been used to manage the integrity of pipelines in HCAs since 2002 and has been updated several times to reflect industry advances to manage the evaluation of conditions, such as dents and cracks more

[175] 49 U.S.C. § 60102(b)(1) & (2)

effectively. The criteria proposed in the NPRM do not reflect such advances, as evidenced by references to a version of ASME B31.8S – 2004 that is outdated.

5. PHMSA's Proposed Immediate "Repair" Criteria Should Be Renamed "Response" Criteria.

a. Remaining Strength – §§ 192.713(d)(1)(i) and 192.933(d)(1)(i)

PHMSA proposes to require operators to repair anomalies with a predicted failure pressure less than or equal to 1.1 times the MAOP using B31G, RSTRENG or equivalent as an immediate response condition. As discussed above, INGAA proposes that anomalies with a predicted failure pressure less than or equal to 1.1 times the MAOP using B31G, RSTRENG or equivalent be investigated as an immediate condition. Repairs would be made using § 192.713(c) and INGAA's proposed § 192.933(e).

INGAA proposes to change how PHMSA proposes to address cracks and crack-like features. INGAA proposes that PHMSA treat crack-like features the same as it treats metal loss, applying remaining strength calculations. While addressed separately in proposed § 192.713(d)(1)(v) and proposed § 192.933(d)(1)(vi), B31.8S recognizes treating the remaining strength of cracks and metal loss similarly.[176] PHMSA should permit operators to respond to cracks, using the well-established Modified Ln Sec analysis method or an equivalent method. INGAA proposes that PHMSA permit operators to use this methodology for responding to cracks rather than responding immediately upon "[a]ny indication of significant stress corrosion cracking (SCC)," as proposed by § 192.713(d)(1)(v) and proposed § 192.933(d)(1)(vi). INGAA's proposal represents a practical and analytical engineering-based approach that is consistent with, and equally as safe as, PHMSA's proposed approach for responding to metal loss. INGAA requests that PHMSA modify proposed § 192.713(d)(1)(i) and proposed § 192.933(d)(1)(i), to allow operators to analyze cracks through methodology such as Modified Ln-sec and to respond according to the evaluated predicted failure pressures. Using this criteria, a crack with a predicted failure pressure less than or equal to 1.1 times MAOP would be an immediate response condition.

PHMSA has recognized in the NPRM that a pipeline that has been pressure tested in accordance with Subpart J test levels can contain manufacturing-related features, which will remain resident unless otherwise acted upon by pressure cycling or outside forces. INGAA proposes new language that stipulates that manufacturing-related features only require a response if the segment has not been tested in accordance with Subpart J test levels.

[176] ASME B31.8S-2012, Managing System Integrity of Gas Pipelines, Code for Pressure Piping at 51, Table A-3.4-1.

b. Dents That Have Any Indication of Metal Loss, Cracking or Stress Riser - §§ 192.713(d)(1)(ii) and 192.933(d)(1)(ii)

PHMSA proposes to require that operators repair dents that have any indication of metal loss, cracking or stress riser. PHMSA has not provided any empirical basis for its proposal. In contrast, ASME B31.8 states that dents associated with metal loss due to corrosion are not injurious except when the metal loss exceeds remaining strength limitations or the dent containing metal loss is greater than 6% of nominal pipe diameter.[177]

The proposed PHMSA rule also does not consider the orientation of a dent with metal loss (*e.g.*, top or bottom of the pipe) to establish the likelihood that the metal loss is the result of mechanical damage rather than non-injurious corrosion. Dents with metal loss on the bottom of the pipe should not require an immediate repair since they are not injurious and typically are corrosion-related. The experience of INGAA members indicates that the vast majority of dents with metal loss identified through in-line inspection tools are associated with corrosion-related metal loss levels that are not injurious when examined and do not require repair in accordance with B31.8-2007 criteria.

Requiring an immediate repair for anomalies that do not represent an injurious condition conflicts with PHMSA's intent in establishing immediate response conditions. If adopted, this criterion would divert resources and distract pipeline operators from addressing conditions that do, as demonstrated by risk data, warrant immediate response. Addressing non-injurious dents with metal loss as immediate conditions also conflicts with various industry standards and guidance. For example, ASME B31.8S-2004, Section 7.2 classifies responses into three groups: immediate; scheduled; and monitored. According to Section 7.2, the indication within the immediate grouping is one that "shows that the defect is at failure point." ASME B31.8S-2004, Section 7.2.3 states that "[i]ndications requiring immediate response are those that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline."

INGAA proposes to address "[a] dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser" as an "immediate response" condition, because it is likely caused by excavation damage. Gouging caused by mechanical damage is much more difficult to size and evaluate reliably. In light of these difficulties, the consensus standards require a more conservative approach. Addressing these top-side dents as immediate response conditions is consistent with the approach reflected in § 195.452(h)(4)(i)(C), applicable to hazardous liquid pipelines.[178] In contrast, bottom-side dents

[177] ASME B31.8-2007, Gas Transmission and Distribution Piping Systems, Code for Pressure Piping at 69, Section 851.41.

[178] 49 C.F.R. § 195.452(h)(4)(i)(C).

that have any indication of metal loss under Part 195 have a 60-day response condition.[179] PHMSA recognizes that dents on the bottom of the pipe are highly likely to be corrosion-related metal loss, which an operator can detect the size and evaluate reliably (and not be an immediate repair condition).[180] INGAA proposes that PHMSA treat bottom-side dents in the same manner.

c. Metal Loss or Crack-Like Feature Greater Than 80% - §§ 192.713(d)(1)(iii) and 192.933(d)(1)(iv)

INGAA agrees with PHMSA's proposal to include a metal loss depth criterion as long as it is considered a response criterion. INGAA further recommends the addition of an 80% depth-based cracking criterion as an immediate condition along with the metal loss depth-based criteria. While PHMSA may not have proposed a cracking criterion as an immediate condition, INGAA recommends adding it to these above-referenced regulations making them consistent with the way PHMSA addresses metal loss.

d. Metal-Loss Affecting a Detected Longitudinal Seam - §§ 192.713(d)(1)(iv) and 192.933(d)(1)(v)

PHMSA proposes that "[a]n indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high frequency electric resistance welding (ERW) or by electric flash welding" is an immediate repair condition. Metal-loss affecting a direct current or low-frequency electric resistance weld or electric flash weld is recognized already in ASME B31.8S-2004 as a condition requiring an immediate response.[181]

PHMSA has not explained or provided data to support its proposal to treat metal loss associated with high-frequency electric resistance welded seams as an immediate repair condition. PHMSA's position also is inconsistent with B31.8S-2004, Section 7.2.1, which does not treat high-frequency electric resistance welded seams as an immediate repair condition.

Corrosion-related metal loss interacting with high-frequency electric resistance weld seams is not subject to selective seam weld corrosion and not considered an injurious condition under any known industry standard. Responding to non-injurious conditions would not improve pipeline safety because it would deploy pipeline integrity resources at the expense of higher-risk conditions elsewhere. This condition does not necessarily meet the standards established in ASME B31.8S-2004, Section 7.2, which provides that "Indications requiring immediate response are those that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline." Corrosion interacting with high-

[179] 49 C.F.R. § 195.452(h)(4)(ii)(B).

[180] 49 C.F.R. § 195.452(h)(4)(iii).

[181] ASME B31.8S-2004, Managing System Integrity of Gas Pipelines at 20, Section 7.2.1.

frequency ERW is non-injurious and does not meet either an immediate or scheduled response requirement.

Responding to defects that do not meet the criteria for an immediate condition undermines an operator's ability to respond in a timely manner to defects that are in fact immediate response conditions. Classifying indications that are not "expected to cause immediate or near-term leaks or ruptures" as immediate response conditions would potentially slow the response to conditions that represent a higher risk to the public and the environment. INGAA requests that PHMSA remove metal-loss affecting a detected longitudinal seam, if that seam was formed *by high-frequency electric resistance welding* from the immediate repair conditions of §§ 192.713(d)(1)(iv) and 192.933(d)(1)(v) .

e. Any Indication of Significant Stress Corrosion Cracking (SCC) – §§ 192.713(d)(1)(v) and 192.933(v)(1)(vi)

PHMSA proposes that "any indication of significant stress corrosion cracking (SCC)" be an immediate condition. PHMSA proposes to define "significant stress corrosion cracking" as it is defined in NACE SP0204-2008 – Stress Corrosion Cracking Direct Assessment.[182] This definition is not part of the current NACE standard and was never intended by NACE to be used for response to ILI or to drive repair decisions. PHMSA also notes that "Stress Corrosion Cracking is listed in ASME/ANSI B31.8S as an immediate repair condition, which is not reflected in the current IM regulations." PHMSA, however, relies upon an outdated 2004 version of B31.8S, which considered response based on the then-recognized capabilities of ILI and does not reflect current ILI capabilities. ASME B31.8S-2010 and later versions treat significant cracking similar to metal loss.

PHMSA further justifies the proposed criteria by citing NTSB recommendation P-12-3. NTSB recommended an "engineering assessment of crack defects," establishing "acceptable methods for performing these engineering assessments" and consideration of "safety factors," which are not addressed within the PHMSA proposal. PHMSA's approach lacks a rational connection to the risks posed by SCC and does not reflect the current technology of ILI tools or modern industry consensus standards, which provide models for evaluating cracks effectively.

PHMSA should delete §§ 192.713(d)(1)(v) and 192.933(d)(1)(vi), "significant stress corrosion cracking," as an immediate repair condition. It should instead reference the failure pressure ratio approach to managing SCC in §§ 192.713(d)(1)(v) and 192.933(d)(1)(vi), which is a more practical engineering-based approach. INGAA's proposed criteria would allow an

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[182] *Compare* NACE SP0203-2008, Stress Corrosion Cracking (SCC) Direct Assessment at 6 (definition of "Significant SCC") and proposed § 192.3 (definition of "Significant stress corrosion cracking"). Note that the NACE definition states that "a crack that is labeled "significant" is not necessarily an immediate threat to the integrity of the pipeline."

operator to calculate a failure pressure and then apply a sufficient safety factor, consistent with PHMSA's approach for metal loss corrosion, in §§ 192.713(d)(1)(v) and 192.933(d)(1)(vi) above. "Significant stress corrosion cracking" is an obsolete term that is not used in the current NACE standard or the current version of the CEPA recommended practice [183] from which the term originated.

"Significant Stress Corrosion Cracking" was first defined in the CEPA Stress Corrosion Cracking Recommended Practice developed in 1997. The term originated in the context of an early form of stress corrosion cracking direct assessment. This term was adopted in the NACE stress corrosion cracking standard, but only in context of establishing a mitigation program such as performing ILI or pressure testing. The definition of "Significant SCC" in the NACE SP0204-2008 standard includes the qualification that "a crack that is labeled significant is not necessarily an immediate threat to the integrity of the pipeline." This demonstrates that the term was never intended to drive response or repair decisions. The term has been removed from the latest versions of both the NACE SCCDA standard CP0204-2015 and the CEPA SCC recommended practice.

INGAA also proposes to incorporate principles from the current industry standards, B31.8S-2014, rather than continue to rely on the outdated 2004 version. The current standards enable operators to evaluate cracking, rather than repair it immediately. The outdated ASME B31.8S-2004, Section 7.2.2 addressed response for "Crack Detection Tools for Stress Corrosion Cracking" and stated that "[a]ll indications of stress corrosion cracks require immediate response." This requirement was written in the context of the far more limited ILI crack detection technologies available at that time. Since then, three updated versions of ASME B31.8S have been published. Each version of B31.8S has updated the language for response to SCC to reflect advances in both Electromagnetic Acoustic Transducer (EMAT) technology and fracture mechanics evaluation capabilities. There is no longer a need to classify all indications of SCC as an immediate response condition, because technology is much better at detecting and sizing SCC for more refined analyses.

PHMSA recognizes EMAT technology in proposed § 192.624(c)(3)(iii) and PHMSA similarly should recognize EMAT technology in proposed § 192.713(d)(1)(i) and § 192.933(d)(1)(i) to address cracks. In §192.624(c)(3)(iii), PHMSA states that "[a]t a minimum, the operator must conduct an assessment using high resolution magnetic flux leakage (MFL) tool, a high resolution deformation tool, and either an electromagnetic acoustic transducer (EMAT) or ultrasonic testing (UT) tool." The last three versions of ASME B31.8S Section 7.2.2 (2010, 2012, and 2014) state that "[i]t is the responsibility of the operator to develop and document appropriate assessment, response, and repair plans when in-line inspection (ILI) is

[183] Canadian Energy Pipeline Association, Stress Corrosion Cracking Recommended Practices at 1-1 (2nd ed. Dec. 2007).

used for the detection and sizing of indications of stress corrosion cracking (SCC)" and no longer mandates immediate response for all cracks. Although ASME B31.8S-2014 assigns responsibility to the operator, INGAA supports a defined crack response approach that requires an operator to establish the burst or failure pressure and then establish response criteria based on safety factor thresholds, similar to the approach PHMSA proposes for conventional corrosion metal loss in proposed § 192.713(d)(1)(i) and § 192.933(d)(1)(i). INGAA proposes that PHMSA allow an operator to evaluate cracks in accordance with the current version ASME B31.8S-2014. PHMSA should require an operator to schedule an immediate response when a predicted failure pressure is less than or equal to 1.1 times the MAOP.

PHMSA also references the Marshall, Michigan, crude oil spill incident and subsequent NTSB recommendations to justify its proposal to respond to all cracks as immediate conditions. PHMSA states:

> With respect to SCC, PHMSA has incorporated repair criteria to address NTSB recommendation P-12-3 that resulted from the investigation of the Marshall, Michigan crude oil accident. From its investigation, the NTSB recommended that PHMSA revise § 195.452 to clearly state (1) when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed; (2) the acceptable methods for performing these engineering assessments, including the assessment of cracks coinciding with corrosion with a safety factor that considers the uncertainties associated with sizing of crack defects; (3) criteria for determining when a probable crack defect in a pipeline segment must be excavated and time limits for completing those excavations; (4) pressure restriction limits for crack defects that are not excavated by the required date; and (5) acceptable methods for determining crack growth for any cracks allowed to remain in the pipe, including growth caused by fatigue, corrosion fatigue, or stress corrosion cracking as applicable (NTSB recommendation P-12-3). Although the recommendation was focused on Part 195, the issue applies to gas pipelines regulated under Part 192.

NPRM at 20,819.

None of the NTSB recommendations support a requirement to examine and evaluate SCC on the basis of a misapplied and obsolete term that originated from direct assessment processes. To the contrary, the first part of NTSB recommendation P-12-3 recommends that PHMSA clearly state "when an engineering assessment of crack defects, including environmentally assisted cracks, must be performed," and the second part recommends that PHMSA establish "the acceptable methods for performing these engineering assessments," including consideration of safety factors. PHMSA's proposed criteria for immediate response do not address either of these recommendations. INGAA's proposed approach and language fulfills the NTSB recommendations by providing an engineering-based solution (*i.e.*, calculation of burst pressure with applied safety factors) and proposed acceptable methods (*e.g.,* Modified Ln Sec or equivalent).

Responding to defects that do not meet the purpose of the immediate response conditions requirement also undermines the response timing for those defects that do meet the definition of immediate response conditions. Classifying indications that are not "expected to cause immediate or near-term leaks or ruptures" as immediate response conditions would potentially slow the response to indications that are legitimate immediate conditions and represent a higher risk to the public and the environment. INGAA requests PHMSA delete § 713(d)(1)(v) and § 192.933(d)(1)(vi). INGAA also requests PHMSA allow operators to manage SCC similar to metal loss as a function of MAOP.

f. Any Indication of Significant Selective Seam Weld Corrosion (SSWC) – PHMSA Should Delete § 192.713(d)(1)(vi) and § 192.933(d)(1)(vii)

PHMSA proposes that operators treat any significant indication of selective seam weld corrosion as an immediate response condition. Because in-line inspection tools cannot reliably identify selective seam weld corrosion and it can be conclusively identified only with visual examination and evaluation. INGAA proposes to move this language to §192.713(d)(1)(iv) and § 192.933(d)(1)(v). In addition, §192.713(d)(1)(vi) and § 192.933(d)(1)(vii) are unnecessary and should be deleted, because response to ILI tool data related to the potential threat of selective seam weld corrosion is addressed using the failure pressure ratio methods described in proposed §192.713(d)(1)(i) and § 192.933(d)(1)(i).

F. Pressure Reductions For Immediate Response Conditions - § 192.713(d)(2): PHMSA's Proposal to Reduce Pressure to the Lower of Two Pressure Reduction Methodologies Is Inconsistent With Existing Regulations and Would Not Add Incremental Safety Benefits.

PHMSA proposes to require an operator to reduce the operating pressure of its affected pipeline until it can remediate the immediate repair conditions identified in § 192.713(d)(1). PHMSA proposes under § 192.713(d)(2)(i) that if SMYS or actual material yield and ultimate tensile strength is not known or adequately documented by RTVC records, the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607, or reduce pressure to 80 % at time of discovery, *whichever method is lower*. PHMSA has not offered any risk-related rationale or other support for the proposed methods for determining an appropriate pressure reduction. It also does not account for industry's ability to conduct engineering analyses to evaluate and calculate safe pressures. INGAA proposes that § 192.713 be changed to give operators the discretion to choose between using engineering analysis, such as B31G or R-STRENG, *or* taking a pressure reduction to 80% of the operating pressure at the time of discovery (without the requirement to use the "lower of" the two options).

PHMSA's proposed §192.713(d)(2) applies to transmission pipelines in non-HCAs; §192.933(a)(1) applies only to HCAs. Section 192.713(d)(2) would require an operator to reduce pressure on transmission pipelines in non-HCAs immediately upon discovery of a (d)(1) event. The pressure reduction requirements in § 192.713(d)(2) for non-HCAs are more stringent than the requirements for pressure reductions in HCAs in §192.933, which gives operators the discretion to choose between using engineering analyses, such as B31G or RSTRENG, or taking a pressure reduction to 80% of the operating pressure at the time of discovery. PHMSA should change §192.713(d)(2) to make it identical to §192.933(a)(1) so that pressure reductions are treated the same in non-HCAs and HCAs.

Pressure reductions are also addressed in § 192.713(b)("Operating pressure must be at a safe level during repair operations.") without the specific methodology proposed in § 192.713(d)(2). Proposed § 192.713(d)(2) conflicts with other proposed regulations and must be changed to reflect the ability to calculate safe pressures through established engineering practices. INGAA proposes to establish safe pressures in compliance with § 192.713(b) using ASME B31G, RSTRENG, Modified Ln-Sec or other equivalent method. INGAA requests PHMSA allow operators to determine a safe pressure consistent with proposed § 192.485(c) and proposed § 192.933(a)(1), which allow an operator to choose between an engineering analysis method or reducing pressure to 80% of the operating pressure at the time of discovery, and not be compelled to use the lower of the two values.

PHMSA has not justified why an operator must take a pressure reduction using the *lower of* a burst pressure with the commensurate safety factor applied *or* 80% of the pressure at the time of discovery. It has not explained why this is a reasonable approach that increases safety, when both methods are based on sound engineering principles and are permitted by § 192.933(a)(1). A sufficient level of conservatism is already built into the evaluation process when the commensurate design factor has been applied to calculate the failure pressure using an approved methodology contained within §192.713(d)(2), such as RSTRENG. Establishing a safe pressure or pressure reduction to 80 percent of discovery is inconsistent with both § 192.933 (HCAs) and §192.485 (non-HCAs). Proposed § 192.485 requires "including the appropriate use of class location and pipe longitudinal seam factors in pressure calculations for pipe defects." Sections 192.485 and 192.933 both indicate that "the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, *see* §192.7) or the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, *see* §192.7) for corrosion defects."

INGAA agrees that a pressure reduction to 80% on immediate anomalies may be appropriate when a safe pressure cannot be established based on a calculated burst pressure. Both methods -- the 20% pressure reduction and the burst pressure calculation -- produce safe pressure levels. One is based on a pipeline's specific data while the 80% pressure level is based on the Subpart J hydrotest. The basis of PHMSA's 80% is that it provides a safety margin that is equivalent to a Subpart J pressure test to 1.25 X MAOP. The 20% reduction is a conservative, gross adjustment, to ensure an operator can achieve a safe pressure. In cases where an operator has data to calculate a burst pressure, applying one of the engineering models described above which factors in a safety margin, it can calculate a safe pressure based on that actual data. A 20% pressure reduction would not be warranted when the calculation is based on actual data for the pipeline that produces an engineering-based, safe pressure level. Establishing a 20% reduction of operating pressure at the time of discovery would not ensure any extra measure of public safety when establishing pressure reductions for metal loss or crack-like defects.

The following example illustrates why the pressure reduction to 80% at the time of discovery achieves a safe pressure is overly conservative.

R-STRENG Calculated Burst Pressure = 995 psig
Design Factor = 0.72 (Class 1)
MAOP = 720 psig
SAFE PRESSURE = Burst Pressure X Design Factor

<u>SAFE PRESSURE = 995 X 0.72 = 716 psig</u>

<u>Safety Factor = BP/SP = 995/716 = 1.39</u>

If the MAOP of a pipeline is 720 psig and the failure pressure established by RSTRENG is 995 psig and the design factor of the pipe is 0.72 (*i.e.*, a 1.39 safety factor), then the calculated safe pressure would be 716 psig (i.e., 995 failure pressure x 0.72 design factor or 995 failure pressure ÷ 1.39 safety factor). Reducing the pressure to 716 psig (*i.e.*, a 4 psig reduction from the MAOP) would provide a safety factor of 1.39, which is commensurate with the design of the pipe. This is recognized by PHMSA and Part 192 as a sufficient safety margin.

If the same anomaly required an operator to reduce its pressure to 80 percent at the time of discovery, the pressure reduction under PHMSA's proposal would be 576 psig, even assuming the pipeline was operating at MAOP at the time of discovery. This resulting level of conservatism would ~1.73, which would be an excessive level of conservatism for a Class 1 location, which requires the pipe to be designed with a safety factor of 1.39. *See* existing §192.111 – Design Factor (F) for Steel Pipe.

G. Two-Year Response Conditions Under New § 192.713(d)(3) and Additional One-Year Response Conditions Under Existing § 192.933(d)(2)

PHMSA proposes to add additional one-year response conditions in § 192.933(d)(2). PHMSA also creates a list of conditions in § 192.713(d)(3) for transmission lines located outside of HCAs that must be repaired within two years of discovery. The criteria listed in § 192.713(d)(3) are modeled on those proposed in § 192.933(d)(2) for pipelines located in

HCAs, except that the latter are subject to a shorter, one-year remediation deadline. PHMSA states that the proposal to create two-year conditions for non-HCA transmission lines "will ensure the prompt remediation of anomalous conditions, while allowing operators to allocate their resources to high consequence areas on a priority basis." NPRM at 20,815.

INGAA proposes that PHMSA rename §192.713(d)(3) as "Two-year response criteria" and § 192.933(d)(2) as "One-year response criteria," rather than "repair" conditions. INGAA further requests PHMSA prioritize the two-year response criteria into (1) two-year responses; and (2) scheduled responses. INGAA requests PHMSA prioritize the one-year response criteria into (1) one-year responses; and (2) scheduled responses.

1. Dents With Metal Loss on the Bottom of the Pipeline – § 192.713(d)(3)(i)

INGAA proposes to require operators to respond to dents with metal loss on the bottom of the pipeline as two-year *scheduled* conditions. As described above, B31.8-2007 indicates that dents associated with metal loss due to corrosion are not injurious except when the metal loss exceeds remaining strength limitations or the dent containing metal loss is greater than 6% of nominal pipe diameter.[184]

INGAA proposes to address these non-injurious, bottom-side dents with metal loss anomalies as scheduled conditions. This is consistent with ASME B31.8S and PHMSA's approach under existing § 195.452 applicable to hazardous liquid pipelines.[185] ASME B31.8S-2004 establishes a scheduled response as an indication that the "defect is significant but not at failure point." The proposed response timing for bottom-side dents with metal loss is supported by industry data confirming that metal loss associated with bottom-side dents are predominantly non-injurious corrosion that do not require repair in accordance with B31.8-2007 requirements. This approach is supported by the negligible effect of cyclic fatigue on gas pipelines relative to liquids pipelines. As a senior PHMSA engineer explained during PHMSA's June 28, 2016 webinar, "Gas pipelines normally don't have cyclic fatigue issues, so on many or most of the lines; this problem will not be too much of a factor."

a. Corrosion and Cracks – § 192.713(d)(3)(iii) and § 192.933(d)(2)(iii)

PHMSA should allow operators to respond to metal loss and crack-like features (§§ 192.713(d)(1) and 192.933(d)(1)), based on remaining strength calculations, rather than identify them as repair conditions, as discussed above. Establishing a scheduled response for

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[184] ASME B31.8-2007, Gas Transmission and Distribution Piping Systems, Code for Pressure Piping at 69, Section 851.41.

[185] 49 C.F.R. §195.452(h)(4)(iii)(C).

cracks based on the calculation of the failure and reasonable safety factor is consistent with the intent and spirit of scheduled response conditions. ASME B31.8S-2004, Section 7.2 classifies responses into three groups: immediate, scheduled and monitored. According to Section 7.2, the indications within the scheduled grouping are those for which "the defect is significant but not at failure point." Therefore, consistent with anomalies that are not at a failure point per ASME, anomalies with a safety factor greater than 1.1 but less than 1.25 should be *scheduled* response.

b. Predicted Metal Loss Greater Than 50% – §§ 192.713(d)(3)(iv) and 192.933(d)(2)(iv)

INGAA recommends that metal loss greater than 50% be deleted as a separate criterion from the final rule. PHMSA has not justified this criterion or provided any specific basis other than to reference requirements in Part 195, the hazardous liquid pipeline safety regulations. The 50% metal criterion is not referenced in any consensus standards as an injurious defect, including ASME/ANSI B31.8S and B31.8, and is not recognized outside of consensus standards as injurious. Operators would calculate metal loss and respond according to the results of the failure pressure calculation as described above (either a one-year response condition under § 192.933(d)(1)(i) or a two-year response condition under § 192.713(d)(1)(i)).

c. Metal Loss Greater Than 50% At a Crossing, Area of Widespread Circumferential Corrosion or Area That Could Affect a Girth Weld – § 192.713(d)(3)(v) and § 192.933(d)(2)(v)

PHMSA proposes three different criteria within § 192.713(d)(3)(v) and § 192.933(d)(2)(v):

i. Metal Loss Greater than 50% at a Crossing of Another Pipeline – §§ 192.713(d)(3)(v) and 192.933(d)(2)(v)

INGAA suggests that the proposed requirement to address metal loss greater than 50% at a crossing of another pipeline is unnecessary and duplicative. PHMSA's proposals in § 192.713(d)(3)(iv) and § 192.933(d)(2)(v) already include "[a]n area of corrosion with a predicted metal loss greater than 50% of nominal wall" in their lists of response conditions. INGAA recommends that the criterion, "metal loss greater than 50% at a crossing of another pipeline," be deleted as a separate criterion from the final rule. Operators would calculate metal loss and respond according to the results of the failure pressure calculation as described above (either a one-year response condition under § 192.933(d)(1) or a two-year response condition under § 192.713(d)(1)(i)).

ii. Metal Loss Greater than 50% in an Area With Widespread Circumferential Corrosion – §§ 192.713(d)(1)(i) and 192.933(d)(2)(v)

PHMSA proposes to include metal loss greater than 50% in an area with "widespread circumferential corrosion" in §§ 192.713(d)(1)(i) and 192.933(d)(2)(v) and as two-year and one-year conditions, respectively. PHMSA does not provide any technical justification for these criteria. The phrase "widespread circumferential corrosion" is unclear, ambiguous and undefined. There is no industry standard that references "widespread circumferential corrosion" as a significant defect or an injurious condition. Circumferential metal loss identified by in-line inspection is evaluated using Mod B31.G, RSTRENG, or equivalent methods described under §§ 192.713(d)(1)(i) and 192.933(d)(1)(i). Safe pressure can be established based on flaw dimensions of the corrosion and an appropriate repair can be determined. For these reasons, INGAA requests that the proposed criteria be omitted from the final rule.

iii. Metal Loss Greater than 50% in an Area that Could Affect a Girth Weld – §§ 192.713(d)(3)(v) and 192.933(d)(2)(v)

PHMSA's proposal to include metal loss "in an area that could affect a girth weld" in §§ 192.713(d)(1)(v) and 192.933(d)(2)(v) as two-year and one-year conditions, respectively, is contrary to the intent of a scheduled response. Section 7.2 of ASME/ANSI B31.8S-2004 indicates that a scheduled response is an indication that shows the "defect is significant but not at failure point." PHMSA's proposed criteria require operators to respond to a potential defect that may not exist, and therefore cannot be deemed significant. The regulatory impact assessment does not analyze the potential costs and benefits of the proposed criteria. INGAA recommends that metal loss in an area that could affect a girth weld be omitted from the final rule. Metal loss is evaluated using Mod B31.G, RSTRENG or equivalent methods described under §§ 192.713(d)(1)(i). and 192.933(d)(1)(i)

iv. A Gouge or Groove Greater than 12.5% of Nominal Wall Thickness – §§ 192.713(d)(3)(vi) and 192.933(d)(2)(vi)

PHMSA proposes in § 192.713(d)(3)(vi) and § 192.933(d)(2)(vi) that an operator respond to a gouge or groove greater than 12.5% of nominal wall thickness as two-year and one-year conditions, respectively. ILI technology, however, currently cannot determine if metal loss is the result of mechanical damage or discriminate between gouges and non-injurious metal loss. INGAA proposes that PHMSA remove "a gouge or groove greater than 12.5%" from the list of two-year and one-year response conditions and permit such conditions found during in-field examination and evaluation to be repaired under § 192.713(c) and INGAA's proposed § 192.933(e). INGAA also proposes to expand the repair options in § 192.713(c) and INGAA's proposed § 192.933(e) to include repair options included within B31.8S-2004, Section 7, Table 4.

INGAA understands that ILI technology that can differentiate gouging and grooving from metal loss is near commercialization. At such a time, gouging and grooving would be evaluated as dents under § 192.713(c) and INGAA's proposed § 192.933(e).

v. Any Indication of Crack or Crack-Like Defect other than an Immediate Condition – §§ 192.713(d)(3)(vii) and 192.933(d)(2)(vii).

PHMSA proposes in § 192.713(d)(3)(vii) and § 192.933(d)(2)(vii) that operators respond to "[a]ny indication of crack or crack-like defect other than an immediate condition" as scheduled two-year or one-year conditions, respectively. INGAA does not agree with the premise that such indications are always injurious conditions. Not all non-immediate cracks warrant a two-year or one-year response. INGAA requests that PHMSA treat cracks or crack-like anomalies according to proposed revised §§ 192.713(d)(1)(i) and 192.933(d)(1)(i). Operators should be able to use Modified Ln Sec or equivalent method to evaluate and respond to crack or crack-like features.

ASME B31.8S addresses crack and crack-like features. PHMSA still relies on the 2004 version of ASME B31.8S. Three subsequent versions of the consensus standard have been published. Each subsequent version of B31.8S includes updated language regarding response to cracking as a result of improvements to EMAT technology development. EMAT technology is recognized by PHMSA within the NPRM at § 192.624(c)(3)(iii), which states that "[a]t a minimum, the operator must conduct an assessment using high resolution magnetic flux leakage (MFL) tool, a high resolution deformation tool, and either an electromagnetic acoustic transducer (EMAT) or ultrasonic testing (UT) tool." Section 7.2.2 of the post-2004 versions of B31.8S states that "[i]t is the responsibility of the operator to develop and document appropriate assessment, response, and repair plans when in-line inspection (ILI) is used for the detection and sizing of indications of stress corrosion cracking (SCC)." B31.8S no longer mandates immediate response for all cracks.

As described above in Section IX.E.5.e of these comments, INGAA's proposed approach and revised regulation text language fulfills the NTSB recommendations by providing an engineering-based solution (*i.e.*, calculation of burst pressure with applied safety factors) and use of acceptable testing methods (*i.e.*, Modified Ln Sec or equivalent).

H. INGAA's Proposed Regulatory Text Relating to Remediation Schedule

§ 192.713 Transmission lines: Permanent field repair of imperfections and damages.

~~(a) *This section applies to transmission lines.* Line segments that are located in high consequence areas, as defined in § 192.903, must also comply with applicable actions specified by the integrity management requirements in subpart O of this part.~~

(a~~b~~) *General.* Each transmission line operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made so as to prevent damage to persons, property, or the environment. Operating pressure must be at a safe level during repair operations.

(b~~c~~) *Repair.* Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe; or

(3) Remediated by an acceptable method as defined in ASME B31.8S, Section 7, Table 4.

~~(b) Operating pressure must be at a safe level during repair operations.~~

(c~~d~~)~~ Remediation~~ *Response schedule.* For pipelines not located in high consequence areas, an operator must complete the ~~remediation~~ evaluation of a condition determined from in-line inspection and must schedule in-field examination according to the response schedules in section (c)(1), (c)(3) and (c)(4) ~~following schedule:~~. Upon completion of in-field examination and evaluation of the conditions, repairs shall be completed based on the criteria and schedule in sections (e) and (f). An operator must complete response to a condition according to a schedule prioritizing the conditions for evaluation and response. Unless a special requirement for responding to certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(1) *Immediate ~~repair~~ response conditions*. An operator must ~~repair the following~~ complete the in-field examination and evaluation of the following conditions immediately upon discovery:

(i) For metal loss or crack or crack-like anomalies, ~~A~~a calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation~~.~~ for metal loss, or Modified Ln Sec 2009 or equivalent for crack-like defects. This is consistent with ASME STP-PT-011 for the assessment of SCC, and has been incorporated into ASME B31.8S. Manufacturing related features meeting the above criteria only require a response if the segment has not been tested in accordance with Subpart J test levels. ~~These documents are incorporated by reference and available at the addresses listed in § 192.7(c). Pipe and material properties used in remaining strength~~

~~calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

(ii) A dent ~~that has any indication of metal loss, cracking or a stress riser.~~ located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.

(iii) Metal loss or cracking greater than 80% of nominal wall regardless of dimensions.

(iv) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency ~~or high frequency~~ electric resistance welding or by electric flash welding.

~~(v) Any indication of significant stress corrosion cracking (SCC).~~

~~(vi) Any indication of significant selective seam weld corrosion (SSWC).~~

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

(2) Until the examination and evaluation ~~remediation~~ of a response condition specified in paragraph (~~d~~c)(1) is complete, an operator must reduce the operating pressure of the affected pipeline to the lower of:

(i) A level that restores the safety margin commensurate with the design factor for the Class Location (as provided in §192.111, §192.611(a)(3), §192.619 and §192.620) in which the affected pipeline is located, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991)) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) for corrosion defects, or Modified Ln Sec 2009 or equivalent for crack-like defects. ~~Both~~These procedures apply to ~~corroded regions~~ anomalies that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used. ~~If SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by reliable, traceable, verifiable, and complete records, then the operator must assume grade A pipe or determine the material properties based upon the material documentation program specified in § 192.607,~~ or

(ii) 80% of pressure at the time of discovery, if a safe pressure cannot be calculated using one of the above methods~~, whichever is lower~~.

(3) *Two-year response conditions*. An operator must ~~repair~~ complete in-field examination and evaluation the following conditions within two years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

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

(iii) For metal loss or crack or crack-like anomalies, anomalies must be investigated if ~~A~~a calculation of the remaining strength of the pipe shows a predicted failure pressure ratio (FPR) at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations. ~~This calculation must adequately account for the uncertainty associated with the accuracy of the tool used to perform the assessment~~. Suitable remaining strength calculation methods include ASME/ANSI B31G, RSTRENG, an alternative equivalent method of remaining strength calculation, Modified Ln Sec 2009 or equivalent for crack-like defects. Manufacturing related features meeting the above criteria only require a response if the segment has not been tested in accordance with Subpart J test levels.

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

(~~v~~iv) A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.

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

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

~~(vii) Any indication of crack or crack-like defect other than an immediate condition.~~

(4) *Monitored conditions*. An operator does not have to schedule the following conditions for ~~remediation~~ in-field examination and evaluation, but must record and monitor the

conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o’clock position and the 8 o’clock position (bottom 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o’clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline’s diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal seam weld, and engineering analyses of the dent and girth weld or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

(iv) A dent that has any indication of metal loss, cracking or a stress riser and an engineering analysis demonstrates that the dent is non-injurious and does not pose a public safety threat.

(v) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low frequency electric resistance welding or by electric flash welding and an engineering analysis demonstrates that the metal loss is non injurious and does not pose a public safety threat.

(de) *Repair Conditions*. An operator must immediately repair the following verified conditions on the pipeline:

(1) Corrosion metal loss or cracking with a remaining strength of the pipe below a predicted failure pressure less than or equal to the failure pressure with the required design factor applied per §§ 192.111, 192.611(a)(3), 192.619, and 192.620. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation, Modified Ln Sec 2009, or equivalent for crack-like defects. This is consistent with ASME STP-PT-011 for the assessment of SCC, and has been incorporated into ASME/ANSI B31.8S.

(2) Corrosion metal loss or cracking in excess of 80% depth.

(3) Dents with a depth greater 6% of nominal pipe diameter, unless the dent strain is less than 6%.

(4) Dents with a depth greater 2% affecting a girth weld or seam weld, unless determined to be safe from an engineering analysis.

(5) Dents that contain corrosion in excess of what is allowed by ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation.

(6) Dents that contain stress corrosion cracking or other cracks.

(7) Mechanical damage including gouges, scrapes, smeared metal (not metal loss due to corrosion) whether or not the mechanical damage is associated with concurrent visible indentation of the pipe.

(8) Any significant selective seam weld corrosion.

(e) *Other conditions*. Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules and methods defined in the operator's Operating and Maintenance procedures.

(f) *In situ direct examination of crack defects.* Whenever required by this part, operators must perform direct examination of known locations of cracks or crack-like defects using inverse wave field extrapolation (IWEX), phased array, automated ultrasonic testing (AUT), or equivalent technology that has been validated to detect tight cracks (equal to or less than 0.008 inches). In-the-ditch examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection and in metallurgy and fracture mechanics for accuracy for the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

§192.933 What Actions Must Be Taken To Address Integrity Issues?

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

(1) *Temporary pressure reduction.* If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating

pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* § 192.7)~~;~~ or AGA Pipeline Research Council~~,~~ International, PR-3-805 (R-STRENG) (incorporated by reference, *see* § 192.7) for corrosion defects, or Modified Ln Sec 2009 or equivalent for crack-like defects to determine the safe operating pressure that restores the safety margin commensurate with the design factor for the Class Location (as provided in § 192.111, § 192.611(a)(3), § 192.619, and § 192.620) in which the affected pipeline is located~~;~~ or reduce ~~by reducing~~ the operating pressure to a level not exceeding 80 percent of the ~~level~~ operating pressure at the time the condition was discovered. ~~Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~ An operator must notify PHMSA in accordance with § 192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or ~~through an~~other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement~~,~~ or an intrastate covered segment is regulated by that State.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, the operator must notify PHMSA under §192.949 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. The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

[…]

(c) *Schedule for evaluation and ~~remediation~~response.* An operator must complete ~~remediation of~~ response to a condition according to a schedule prioritizing the conditions for evaluation and ~~remediation~~response. Unless a special requirement for ~~remediating~~ responding to certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling ~~remediation~~*response—

(1) *Immediate ~~repair~~ response conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate ~~repair~~response conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate ~~repair~~response conditions:

(i) For metal loss or crack or crack-like anomalies, a ~~A c~~Calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly for any class location. Suitable remaining strength calculation methods include~~,~~ ASME/ANSI B31G (incorporated by reference, *see* § 192.7), PRCI PR-3-805 (R-STRENG) (incorporated by reference, *see* § 192.7);~~,~~ or an alternative equivalent method of remaining strength calculation for metal loss, or Modified Ln Sec 2009 or equivalent for crack-like defects. This is consistent with ASME STP-PT-011 for the assessment of SCC, and has been incorporated into ASME B31.8S. Manufacturing related features meeting the above criteria only require a response if the segment has not been tested in accordance with Subpart J test levels. ~~that will provide an equally conservative result. Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607.~~

(ii) ~~A dent that has any indication of metal loss, cracking or a stress riser.~~ A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.

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

(iv) Metal loss or cracking greater than 80% of nominal wall regardless of dimensions.

(v) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency~~,~~ ~~or high frequency~~ electric resistance welding or by electric flash welding.

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

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

(2) *One-year response conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must ~~remediate~~ complete in-field examination and evaluation of any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper $\frac{2}{3}$ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

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

(iii) For metal loss or crack or crack-like anomalies, anomalies must be investigated if a ~~A~~ calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations. Suitable remaining strength calculation methods include ASME/ANSI B31G, RSTRENG, an alternative equivalent method of remaining strength calculation, Modified Ln Sec 2009 or equivalent for crack like defects. Manufacturing related features meeting the above criteria only require a response if the segment has not been tested in accordance with Subpart J test levels.

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

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

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

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

~~(vii) Any indication of crack or crack-like defect other than an immediate condition.~~

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for ~~remediation~~ in-field examination and evaluation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom $\frac{1}{3}$ of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper $\frac{2}{3}$ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

(iv) A dent that has any indication of metal loss, cracking or a stress riser and an engineering analysis demonstrates that the dent is non-injurious and does not pose a public safety threat.

(v) An indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low frequency electric resistance welding or by electric flash welding and an engineering analysis demonstrates that the metal loss is non injurious and does not pose a public safety threat.

(e) *Repair*. Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe; or

(3) Remediated by an acceptable method as defined in ASME/ANSI B31.8S, Section 7, Table 4.

(f) *Repair Conditions*. An operator must immediately repair the following verified conditions on the pipeline:

(1) Corrosion metal loss or cracking with a remaining strength of the pipe below a predicted failure pressure less than or equal to the failure pressure with the required design factor applied per § 192.111, § 192.611(a)(3), § 192.619 and § 192.620. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation, Modified Ln Sec 2009, or equivalent for crack-like defects. This is consistent with ASME STP-PT-011 for the assessment of SCC, and has been incorporated into ASME/ANSI B31.8S.

(2) Corrosion metal loss or cracking in excess of 80% depth.

(3) Dents with a depth greater 6% of nominal pipe diameter, unless the dent strain is less than 6%.

(4) Dents with a depth greater 2% affecting a girth weld or seam weld, unless determined to be safe from an engineering analysis.

(5) Dents that contain corrosion in excess of what is allowed by ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation.

(6) Dents that contain stress corrosion cracking or other cracks.

(7) Mechanical damage including gouges, scrapes, smeared metal (not metal loss due to corrosion) whether or not the mechanical damage is associated with concurrent visible indentation of the pipe.

(8) Any significant selective seam weld corrosion.

X. Internal Corrosion §§ 192.478 and 192.935

In §§ 192.478 and 192.935, PHMSA proposes new requirements for managing internal corrosion applicable to all transmission pipelines. PHMSA has failed to justify its proposal in § 192.478 to require that all operators develop and implement prescriptive monitoring and mitigation plans to identify potentially corrosive constituents being transported and mitigate their potential corrosive effects. NPRM at 20,830. As required by existing 49 C.F.R. § 192.477, operators already have plans to address potentially corrosive constituents based on the operational attributes of affected pipe segments. The proposed regulations are too prescriptive, unnecessary and overly broad. If implemented, these requirements will increase costs without increasing safety. PHMSA also has not justified its proposal in § 192.935 to require the operators of all pipe segments located in HCAs comply with new, comprehensive and prescriptive internal corrosion measures. INGAA is particularly concerned with the proposed new preventive and mitigative requirement in § 192.935(f) that operators install "continuous gas quality monitoring equipment" at all points where gas with potentially deleterious contaminants enter the pipeline. NPRM at 20,846.

A. PHMSA's Proposed Changes to Certain Internal Corrosion Control Requirements in Proposed § 192.478 Are Duplicative and Unnecessary.

PHMSA proposes to adopt a new internal corrosion requirement in proposed § 192.478 that would require operators to implement programs for monitoring, evaluating, and mitigating the effects of potentially corrosive constituents on the internal condition of a pipe. Under proposed § 192.478, potentially corrosive constituents would include carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water (whether acting individually or in combination). Onshore gas transmission operators would be required to evaluate each corrosive constituent (either individually or in combination with other corrosive constituents) and assess the effect of those constituents on the internal condition of the pipe and implement mitigation measures. The proposed monitoring and mitigation program would require the use of continuous gas quality monitoring equipment at points where potentially corrosive contaminants enter a pipeline, and the use of product sampling, inhibitor injections, cleaning pigs, filters/separators, or other technology to mitigate the effects of these contaminants. NPRM at 20,830.

Section § 192.478(b)(3) would require onshore gas transmission operators to conduct an evaluation *twice* each calendar year, at intervals not to exceed 7.5 months, to determine if internal corrosion is being effectively monitored and mitigated. This type of monitoring is required only once per year in HCA pipe operating at pressures below 30 % of SMYS.[186] The

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[186] *See* 49 C.F.R. § 192.941.

proposed regulation states that coupons or other suitable means must be used to determine the effectiveness of an operator's internal corrosion mitigation measures, and that each coupon or other means must be evaluated twice each calendar year, not to exceed 7.5 months. Onshore gas transmission operators also would be required to review the proposed internal corrosion monitoring and mitigation program at least twice each calendar year, not to exceed 7.5 months, to determine if adjustments are necessary.

Proposed § 192.710(c)(8)(ii) also contains internal corrosion monitoring provisions that are applicable to pipe segments with an MAOP less than 30 % of SMYS. Operators of such lines would be required to conduct a gas analysis for corrosive agents at least two times per year. For segments located in a storage field, an operator would be required to test fluids removed from the storage field on an annual basis, § 192.710(c)(8)(ii)(B), rather than twice each calendar year as required under § 192.478(b). The NPRM does not explain the relationship between § 192.710(c)(8)(ii)(B) and § 192.478(b).

To justify the proposed changes, PHMSA asserts that "the current requirements for internal corrosion control are non-specific," and that "there is benefit in enhancing the current internal corrosion control requirements to establish a more effective minimum standard for internal corrosion management." NPRM at 20,784. PHMSA also acknowledges that, while existing § 192.477 requires that an operator monitor lines carrying corrosive gas for internal corrosion, "the existing rules do not prescribe that operators continually or periodically monitor the gas stream for the introduction of corrosive constituents through system changes, changing gas supply, upset conditions, or other changes." NPRM at 20,810. According to PHMSA, "[t]his could result in pipelines that are not monitored for internal corrosion, because an initial assessment did not identify the presence of corrosive gas." NPRM at 20,810. PHMSA also states that the agency issued an advisory bulletin on internal corrosion monitoring and evaluation in September 2000 following a gas transmission line incident in Carlsbad, New Mexico, and that operators reported 206 incidents attributable to internal corrosion between 2002 and 2012. NPRM at 20,810.

While INGAA recognizes that internal corrosion can have a detrimental effect on a pipeline, the entirety of the proposed regulation is neither necessary nor appropriate. As explained in INGAA's January 2012 comment letter in this proceeding,[187] onshore gas transmission operators are already taking comprehensive steps to address internal corrosion under Subparts I and O of the current regulations. PHMSA's regulations issued after the Carlsbad incident added design and construction standards for managing internal corrosion.[188] The NPRM fails to acknowledge the positive safety impacts of these regulations on reducing

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[187] INGAA, Comments on ANPRM (Jan. 20, 2012).

[188] Pipeline Safety: Design and Construction Standards To Reduce Internal Corrosion in Gas Transmission Pipelines, 72 Fed. Reg. 20,055 (Apr. 23, 2007).

incidents attributable to internal corrosion. In addition, industry follows guidance standards, such as NACE SP0106 – 2006 – Control of Internal Corrosion in Steel Pipelines and Piping Systems, which provide specific measures to manage internal corrosion.

The number of gas transmission line incidents attributable to internal corrosion is steadily declining. INGAA cannot determine how PHMSA derived the statistic cited in the NPRM of 206 incidents attributable to internal corrosion from 2002 to 2012. INGAA's review of PHMSA incident reports shows that there were 68 reported internal corrosion-related incidents in non-HCAs during the same time period. The solutions proposed in the NPRM would have had a minimal effect in preventing any of the 68 incidents because the cause of the internal corrosion would not have been addressed by the proposed regulation. For these reasons, PHMSA should eliminate proposed § 192.478 from the final rule.

If PHMSA retains proposed § 192.478, the final rule must provide clarification to address technical inaccuracies and eliminate duplicative requirements. Many of the potentially corrosive constituents listed in the proposal, e.g., carbon dioxide, sulfur, and hydrogen sulfide, are not corrosive in and of themselves. Liquid water or another electrolyte must be present before these constituents can have a potentially corrosive effect. Similarly, the partial pressure calculations required by the proposed rule for some of the potentially corrosive constituents (*e.g.*, sulfur, microbes, and free water) technically cannot be calculated. In addition, the generic reference to microbes is overbroad, because some types of microbes do not cause or contribute to internal corrosion. INGAA's recommended revisions to the proposed regulatory text clarify these points. Failure to make these clarifications would render proposed § 192.478 inconsistent with NACE SP0106-2006 Appendices B and C, which address impurities.

Proposed § 192.478(b)(1) fails to provide meaningful parameters for the term "gas-quality monitoring equipment." Nor does the NPRM preamble shed any light on this. NPRM at 20,810. The proposed rule could be interpreted to require continuous monitoring of the gas stream for potentially corrosive contaminants, which is not practicable or feasible, particularly for microbes for which no continuous monitoring equipment exists. The proposed regulation also lists "product sampling" as a mitigation measure in paragraph (b)(2) instead of as a monitoring technique in paragraph (b)(1). These shortcomings must be clarified in the final rule.

The internal corrosion monitoring requirement proposed in § 192.478(c) is identical to the requirement in existing § 192.477. The NPRM provides no basis for including redundant regulations. Proposed § 192.478(c) should be withdrawn to avoid unnecessary confusion.

PHMSA also offers no technical support for the biannual program review requirement in proposed § 192.478(d). NPRM at 20,830. Requiring reviews at this interval is unnecessary and excessive, particularly for pipeline systems that are not susceptible to internal corrosion (e.g., dry gas systems). Mitigation of internal corrosion is necessary only if a pipeline is transporting or has the potential to transport corrosive gas. Requiring mitigation measures for systems that do not contain potentially corrosive constituents would be unnecessary, impracticable, and costly. PHMSA should eliminate § 192.478(d) from the final rule.

B. § 192.935 What Additional Preventive and Mitigative Measures Must an Operator Take?

Proposed § 192.935 requires an operator to take measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in an HCA. NPRM at 20,846. PHMSA justifies the additional internal corrosion measures on the basis that the current requirements are "non-specific." NPRM at 20,784.

Proposed § 192.935(f)(2), for example, would require use of "continuous gas quality monitoring equipment" at "points where gas with potentially deleterious contaminants enters the pipeline." The requirement to implement this and other prescriptive measures under §§ 192.935(a) and (f) is not limited to pipelines with an identified threat of internal corrosion, and does not grant the operator the flexibility to prioritize higher risk pipeline segments or to exclude those pipeline segments where internal corrosion is not a threat. PHMSA has not demonstrated why all pipelines in HCAs "must take additional measures beyond those already required by Part 192."[189] The proposal is inconsistent with section 5.1.2 of NACE SP0106-2006, which provides that, if the product transported is not corrosive, certain considerations may be "rejected." Given the compliance cost and the limited benefits that will result from these changes, the NPRM's blanket assertion that such enhancements have "benefit" is insufficient to justify the need for the proposed revisions.

1. Section 192.935(f) Should Be Modified to Permit Operators to Tailor Internal Corrosion Preventive and Mitigation Measures Based on the Operational Characteristics of a Specific Pipe Segment

Proposed § 192.935(f) establishes several prescriptive measures intended to enhance an operators internal corrosion program on a covered segment. INGAA agrees that operators should continually enhance their internal corrosion programs, but it recommends that operators be permitted to implement measures uniquely designed to eliminate the root causes of a potentially corrosive environment on each pipeline segment. Appropriate preventive and mitigative measures will vary significantly depending on the source of gas and the operating parameters of the pipeline. Requiring operators to implement the complete list of measures proposed in § 192.935(f) would compel operators to expend resources on activities that would not achieve any incremental safety benefit. Rather, operators should be permitted to manage internal corrosion using one or more methods identified by an operator as effective based on the unique factors of its affected pipeline.

[189] Proposed § 192.935(a).

PHMSA has failed to provide a technical explanation or justification for adding more strenuous and prescriptive internal corrosion measures for pipelines in HCAs. In proposed § 192.935's preamble, PHMSA says it "has determined that some additional prescriptive preventive and mitigative measures are needed to assure that public safety is enhanced in HCAs and affords greater protections for HCAs." This proposed rule "would add specific enhanced measures for managing external corrosion and internal corrosion inside HCAs." NPRM at 20,819. PHMSA has failed to explain why this regulation must apply to all pipeline segments in HCAs, including those that do not have an identified threat of internal corrosion. No internal corrosion incidents in interstate and intrastate HCAs were reported to PHMSA from 2010-2015.[190] The NPRM also fails to acknowledge that in April 2007, PHMSA added new subsection § 192.143 and expanded § 192.476 to address design and construction standards for managing internal corrosion.[191] The resources required to comply with the proposed § 192.935 would more effectively be deployed to reduce other risks.

When issuing a final rule, PHMSA is required to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'"[192] Given the empirical data, PHMSA cannot justify any assertion that the current § 192.935 is inadequate and requires additional specificity "to establish a more effective minimum standard for internal corrosion management." NPRM at 20,784.

In addition to the current internal corrosion regulations, the NPRM fails to acknowledge that pipelines already manage internal corrosion by monitoring gas quality specifications at comingling points, installing filter separators and dehydrators at key system input points, and blending wet gas with dry gas. The NPRM does not acknowledge that interstate natural gas pipelines must have gas quality specifications in their FERC-approved tariffs.[193] Pipelines typically monitor the quality of gas entering their systems at key receipt points where smaller, lower volume lines connect. This ensures that gas is blended sufficiently to meet the gas quality specifications set forth in each pipeline's tariff. Operators monitor gas quality at smaller-volume receipt points and other points by conducting periodic manual sampling. Operators post gas quality data for key locations representing mainline gas flow on their websites, as required

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[190] This statement is based on the analysis of the PHMSA Incident Reports at http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files

[191] Pipeline Safety: Design and Construction Standards to Reduce Internal Corrosion in Gas Transmission Pipelines, 72 Fed. Reg. 20,055, 20,059 (Apr. 23, 2007).

[192] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines v. United States*, 371 U.S. 156, 168 (1962)) (vacating as arbitrary and capricious final rule that rescinded regulations without adequate explanation).

[193] *Indicated Shippers v. Trunkline Gas Co. LLC*, 105 FERC ¶ 61,394, at P 15 (2003) ("Gas quality standards are practices of the pipelines and operational conditions and must be included in the pipelines' tariffs.") (internal citations omitted).

under their FERC tariffs. The effectiveness of these methods are reflected in the reduced number of incidents attributed to internal corrosion.

Since issuing the NPRM, PHMSA has made several statements undercutting the stated need for the broad-based proposed measures. PHMSA acknowledged that the proposed requirement to use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion, is not applicable to dry gas systems. This contradicts the proposed regulation, which would require all operators in HCAs, including those operating dry gas systems, to comply with all of the listed measures in proposed § 192.935(f).

PHMSA has failed to demonstrate that the added cost of implementing every preventive and mitigative measure in § 192.935(f) would provide corresponding safety benefits when compared with allowing operators to implement preventive and mitigative measures in the most appropriate way based on the operating history and risk profile of each system or segment. Installing continuous monitoring systems at each pipeline receipt point "where gas with potentially deleterious contaminants enters the pipelines" is unnecessary and costly. Each continuous monitoring system would include a gas chromatograph, moisture analyzer, and sulfur analyzer, costing a total of approximately $250,000 at each point. A single pipeline may have hundreds of receipt points. If continuous monitoring systems were installed on a pipeline with just 100 locations, that pipeline's cost to install would be $25 million. There are 153 interstate pipelines. If each pipeline has at least 100 receipt points, then the industry-wide cost of implementing this provision would be well over $1 billion. These costs are not accounted for in the PRIA which erroneously asserts that "the added costs of monitoring . . . is either nothing or relatively inexpensive."[194] The PRIA represents the entire cost for all of industry as $400,000.[195] These costs are not commensurate with the negligible safety benefits relating to internal corrosion. PHMSA has not demonstrated why its proposed changes would improve safety.

PHMSA has not made a rational connection between the facts found and the choice made.[196] PHMSA's authority to issue safety standards also is constrained by the PSA, which requires that a safety standard be "practicable" and designed to meet gas pipeline safety needs and protect the environment.[197] When prescribing any safety standard, PHMSA must consider relevant available gas pipeline safety information, environmental information, the appropriateness of the standard for the type of transportation or facility and reasonableness.[198]

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[194] PRIA at 90, § 3.4.4.4.

[195] PRIA at 91, § 3.4.4.4, Table 3-75 The stated cost in the PRIA is less than what it may cost an individual pipeline to implement this aspect of the regulation.

[196] *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 839, 843 (D.C. Cir. 2006); *Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

[197] 49 U.S.C. § 60102(b)(1).

[198] 49 U.S.C. § 60102(b)(2).

For these reasons, INGAA proposes that § 192.935(f) apply only to pipeline segments with a history of internal corrosion, consistent with the required risk analysis that is performed to determine whether preventive and mitigative measures are necessary. The proposed measure should not apply to all pipelines segments in an HCA. In addition, proposed § 192.935(f) must permit operators to tailor appropriate preventive and mitigative measures based on a risk assessment and the specific characteristics of an individual pipeline segment. INGAA's proposal promotes the continual improvement of integrity management in a cost-effective manner that is consistent with the requirements of the PSA.

C. INGAA's Proposed Regulatory Text Relating to Internal Corrosion

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

(a) For non-dry gas onshore transmission pipelines, each operator must develop and implement a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects. Potentially corrosive constituents include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and ~~free~~ liquid water, either by itself or in combination. Each operator must evaluate the partial pressure of each corrosive constituent (where applicable) by itself or in combination to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.

~~(b) The monitoring and mitigation program in paragraph (a) of this section should consider methods such as:~~

~~(1) Gas quality monitoring at points where gas with potentially corrosive contaminants enters the pipeline, to determine the gas stream constituents;~~

~~(2) Options such as product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents where corrosive gas is being transported;~~

~~(3) Evaluation each calendar year, at intervals not to exceed 15 months, of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated where corrosive gas is being transported.~~

~~(c) If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked at least twice each calendar year, at intervals not exceeding 7 ½ months.~~

~~(d) Each operator must review its monitoring and mitigation program at least twice each calendar year, at intervals not to exceed 7 ½ months, based on the results of its gas stream sampling and internal corrosion monitoring in (a) and (b) and implement adjustments in its monitoring for and mitigation of the potential for internal corrosion due to the presence of potentially corrosive gas stream constituents.~~

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

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. ~~An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to,~~ Such additional measures must be based on the risk analyses required by § 192.917, and ~~must~~ may include, but are not limited to:

[…]

(f) *Internal corrosion*. For segments with an identified internal corrosion threat, ~~As~~ an operator ~~gains information about internal corrosion, it~~ must enhance its internal corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to internal corrosion. At a minimum, as part of this enhancement, operators ~~must~~ should, based on a risk analysis for the pipeline segment, consider implementing any of the following ~~must—~~

(1) Monitor for, and mitigate the presence of, deleterious gas stream constituents.

(2) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators ~~and~~ or continuous gas quality monitoring equipment, or take other appropriate steps to mitigate the risk associated with deleterious contaminants.

(3) At least once per quarter, use gas quality monitoring equipment that may include~~s~~, ~~but is not limited to,~~ a moisture analyzer, chromatograph, carbon dioxide sampling, ~~and~~ or hydrogen sulfide sampling.

(4) Use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion.

(5) Use inhibitors when corrosive gas or corrosive liquids are present.

~~(6) Address potentially corrosive gas stream constituents as specified in § 192.478(a), where the volumes exceed these amounts over a 24-hour interval in the pipeline as follows:~~

~~(i) Limit carbon dioxide to three percent by volume;~~

~~(ii) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and~~

~~(iii) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas. If the hydrogen sulfide concentration is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.~~

(7) Review the program at least semi-annually based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.

XI. External Corrosion

INGAA agrees with PHMSA about the importance of measures to ensure that adequate levels of cathodic protection are maintained on pipeline facilities. The NPRM proposes overly prescriptive and inflexible provisions that would require coating survey assessment methods that are not the most effective approaches to detecting and managing the conditions that present the greatest threat to maintaining adequate levels of cathodic protection. Operators should be permitted select to alternative assessment technologies, such as close interval surveys and high resolution geometry in-line-inspection tools, following construction and pipeline repairs or replacement, to detect and manage conditions that may be harmful to maintaining adequate levels of cathodic protection. An operator should be permitted to tailor remediation responses based on its knowledge of the pipeline and its operational conditions. If PHMSA retains the coating survey requirement, the proposed threshold values for performing remediation should be eliminated. Operators should not be required to implement corrosion-prevention and mitigation measures on pipe segments not subject to corrosion as an integrity threat. The proposed compliance timeframes also should be revised to align with current requirements, and allow operators sufficient time to obtain information, develop remedial measures, and obtain any necessary governmental approvals and permits.

A. Overview of PHMSA's Proposal

The NPRM would establish new requirements for coating surveys and interference current assessments. Proposed §§ 192.319(d) and 192.461(f) would require that transmission line operators perform coating surveys, using DCVG or ACVG, to assess coating integrity after backfilling a pipeline following construction, or a repair or replacement resulting in the backfill of 1,000 or more feet of pipeline. NPRM at 20,829. These assessments would be required no later than three months after placing the line into service or following the repair or replacement. Operators would be required to repair any coating damage classified as moderate or severe according to NACE SP0502, within six months of the assessment.

Under proposed § 192.935(g)(2), operators would be required to perform similar measures for pipe segments located in HCAs at least every seven years. In addition, if annual test station inspections reflect insufficient cathodic protection levels, an operator would be required to perform remediation within six months and perform a close interval survey on both sides of the affected test station to confirm that adequate corrosion control has been restored. Under proposed § 192.935(g) close interval surveys must be performed with the cathodic protection current interrupted. NPRM at 20,847.

The NPRM acknowledges that existing corrosion control requirements are effective in reducing incidents caused by external corrosion. PHMSA expressed concern that its regulations are too general and do not address issues "that experience has shown are important to protecting pipelines from corrosion damage." NPRM at 20,781, 20,782. Relying on "lessons learned" from certain incidents and the improved capabilities of corrosion evaluation tools and methods, PHMSA asserts that "more specific minimum requirements are needed [to] control" external corrosion. NPRM at 20,781. PHMSA cites the following incidents to support more specific minimum requirements to control corrosion: the 2012 incident in Sissonville, West Virginia, the 2007 incident in Delhi, Louisiana, the Bison pipeline incident in 2011, and the crude oil pipeline accident in Marshall, Michigan. NPRM at 20,781, 20,809. PHMSA attributes the pipeline failure on the Bison pipeline to latent coating and mechanical damage caused during construction, and states that coating disbondment contributed to the accident in Marshall, Michigan. NPRM at 20,809. For HCAs, PHMSA states that enhanced corrosion control measures are intended to provide additional protection from the threat of corrosion. NPRM at 20,820.

B. Proposed Sections Are inflexible, Inconsistent With Existing Provisions, Overly Broad, and Would Require the Allocation of Resources to Activities That Will Not Increase the Margin of Safety

1. PHMSA should allow operators to use other assessments tools to detect and manage post-construction issues.

The NPRM prescribes an inflexible approach to managing a pipeline's cathodic protection in proposed §§ 192.319(d) and 192.461(f). PHMSA should allow operators the flexibility to use other assessment technologies, such as close interval surveys and high resolution geometry in-line inspection tools, to detect and manage post-construction and post-repair and replacement conditions that contribute to external corrosion. While INGAA understands PHMSA's concerns about coating damage during construction, the more important concern should be the adequacy of cathodic protection. Coating holidays[199] often have no effect on the adequacy of cathodic protection. NACE SP 0169 places cathodic protection and coatings in context.

> External corrosion control must be a primary consideration during the design of a pipeline system. Materials selection and coatings are primary methods of external corrosion control. Because perfect coatings are not feasible, CP should be used in conjunction with coatings for extended corrosion protection.[200]

Operators should be permitted to focus resources on the assessments, such as close interval surveys, designed to ensure that a pipeline has an adequate level of cathodic protection

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[199] "A holiday is a discontinuity or break in the anti-corrosion coating on pipe or tubing that leaves the bare metal exposed to corrosive processes." PHMSA Pipeline Glossary, https://primis.phmsa.dot.gov/comm/Glossary/index.htm#Holiday (last accessed June 30, 2016)

[200] NACE SP0169-2013, Control of External Corrosion on Underground or Submerged Metallic Piping Systems at 9.

to protect the pipeline properly from external corrosion. To address mechanical damage, a high-resolution geometry tool will identify construction-caused dents that can adversely affect pipeline integrity. These dents would not always be detected using PHMSA's proposed methodology. Performing these assessments is among the most effective means to ensure that a pipeline is adequately protected from external corrosion and construction damage.

DCVG and ACVG equipment allows an operator to detect and determine the relative size of a coating defect by measuring the voltage gradient between the soil surface and the pipeline. This testing is valuable for new pipelines, but is not effective on older pipelines. DCVG and ACVG cannot always detect coating disbondment, unless the coating is cracked and the pipe metal is in contact with an electrolyte such as water or soil. DCVG will not be able to detect coating disbondment if the coating is separated from the pipe. These tests are most effective when data from other inspection tools (such as a close interval survey or an in-line-inspection tool) are integrated to identify actionable anomalies. Coating surveys are not intended to identify mechanical damage to the body of a pipeline. These surveys, however, may identify mechanical damage that is coincident with coating damage. INGAA requests that PHMSA modify proposed § 192.319(f) to permit operators the ability to use the combination of a close interval survey and high-resolution geometry tool as an alternative to a DCVG or ACVG survey to identify and manage post-construction threats. This would be consistent with PHMSA's recognition of close interval survey as a "well-established corrosion control tool." NPRM at 20,781.

When issuing a final rule, PHMSA must "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'"[201] PHMSA's explanation for its decision "may not be superficial or perfunctory"[202] and must be consistent with the evidence.[203] The most significant contributing factor to external corrosion is inadequate cathodic protection, which is most effectively detected by performing a close interval survey. A coating survey may detect the existence of a holiday, but the survey does not provide complete information about the adequacy of cathodic protection, which may be unaffected by a coating defect.[204]

The incidents referenced in the NPRM do not justify requiring DCVG and ACVG coating surveys. In the Marshall, Michigan, accident, a coating survey may have identified disbondment but would have not identified the location at which the pipeline failed. NTSB

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[201] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines v. United States*, 371 U.S. 156, 168 (1962)) (vacating as arbitrary and capricious final rule that rescinded regulations without adequate explanation).

[202] *Owner-Operator Indep. Drivers Ass'n v. FMCSA*, 656 F.3d 580, 588 (7th Cir. 2011) (applying *State Farm* standard and vacating final rule as arbitrary and capricious).

[203] *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 839, 843 (D.C. Cir. 2006) (vacating agency rule because record evidence did not support existence of the problem the rule purported to address).

[204] *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 839, 843 (D.C. Cir. 2006).

concluded that corrosion fatigue cracks that grew and coalesced from crack and corrosion defects under disbonded polyethylene tape coating probably caused the pipeline rupture. Based on this root cause, it is unlikely that coating anomaly tools would have identified a coating anomaly and this potential condition. Coating surveys would not have targeted the area of the failure in this instance. An integrity assessment method such as ILI is used to identify and size metal loss and crack-like features, not DCVG and ACVG surveys.

The other incidents referenced in the NPRM do not support requiring DCVG or ACVG following construction or a repair or replacement. The contributing cause of the Sissonville accident was shielding, which prevented the electric current from reaching the pipe. DCVG and ACVG cannot detect shielding caused by a road-crossing casing. The contributing factor to the Delhi incident -- corrosion inside a casing at a road crossing -- would not have been detected by DCVG or ACVG, because the casing would have prevented the survey tool from assessing the condition of the pipeline's coating. PHMSA's investigation of this failure does not support the agency's conclusion. PHMSA's investigation report of the Bison failure states that a DCVG survey and ILI geometry tool inspection were conducted after construction.[205] Neither survey indicated an actionable anomaly, using the criteria proposed in the NPRM.[206] PHMSA determined the failure resulted from cracking within a dent that had been enlarged by ductile tearing during the pre-commissioning hydrostatic testing followed by a pressure cycle from zero to MAOP.[207]

PHMSA has not explained why coating surveys, like DCVG and ACVG, should be required to detect coating issues after construction or after performing a repair or replacement. The lack of an explanation is particularly troubling because coating surveys do not detect the most significant factor contributing to external corrosion, namely, inadequate cathodic protection. Requiring DCVG and ACVG is inconsistent with PHMSA's stated desire to rely on "improved capabilities of corrosion evaluation tools and methods." NPRM at 20,781. DCVG and ACVG do not detect post-construction mechanical damage, another factor PHMSA cites as contributing to pipeline incidents. Rather, close interval surveys and high resolution geometry pigs are far more effective at detecting and managing these post-construction threats. PHMSA has not presented adequate justification to require DCVG or ACVG to assess whether coating is damaged after a pipeline is backfilled after construction or a repair or replacement in proposed

[205] PHMSA Western Region, Failure Investigation Report – TransCanada/Bison Pipeline Natural Gas Transmission Release near Gillette, WY (Nov. 7, 2012).

[206] PHMSA Western Region, Failure Investigation Report – TransCanada/Bison Pipeline Natural Gas Transmission Release near Gillette, WY at 6 (Nov. 7, 2012).

[207] PHMSA Western Region, Failure Investigation Report – TransCanada/Bison Pipeline Natural Gas Transmission Release near Gillette, WY at 8 (Nov. 7, 2012). Note that enlargement of an otherwise non-injurious feature caused by hydrostatic testing is another reason for using ILI in lieu of hydrostatic test.

§§ 192.319 and 192.461(f). These requirements are excessive and would divert valuable resources away from more pressing safety concerns.

2. The Proposed Threshold Values For Requiring Remediation Are Unnecessarily Inflexible.

If PHMSA retains the requirement that operators perform coating surveys using DCVG and ACVG, PHMSA's proposed threshold values (voltage drop greater than 35% for DCVG or 50dBμV for ACVG) for remediation or repairs are unnecessarily inflexible because they require action without adequate information. These thresholds arbitrarily constrain an operator's ability to determine whether a coating issue actually creates a risk that cannot be adequately addressed with additional cathodic protection. The size of an indication in a coating survey is a function of many factors, including depth of cover, pipe diameter, and soil resistivity.[208] If cathodic protection is adequate, the size of a coating holiday may not be an accurate indicator of the level of external corrosion- related risk. Requiring an operator to remediate or repair a coating indication based solely on its size prevents an operator from making a fact-based engineering determination regarding the appropriate response, if any. NACE SP 0169 provides context for the respective roles of coating and cathodic protection.

> The functions of external coatings are to control corrosion by isolating the external surface of the underground or submerged piping from the environment, to reduce CP current requirements, and to improve current distribution.[209]

PHMSA has not demonstrated the need for strict application of the proposed repair threshold values. The proposed threshold values for performing remediation should be eliminated.

3. The Proposed Timelines For Performing Assessments and Remediation Should Be Aligned With Existing Regulatory Requirements.

Assuming that PHMSA retains the proposed requirement for coating surveys following backfill of the pipeline, the three-month compliance timeframe for completing assessments is inconsistent with the one-year allowed to install cathodic protection and place it into operation after construction of a pipeline in existing § 192.455(a)(2). As drafted, these inconsistent regulatory requirements would create compliance difficulties. PHMSA should revise § 192.319 to permit an operator to perform DCVG within three months of cathodic protection system

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[208] Oliver C. Moghissi, *et al.*, Predicting Coating Holiday Size Using ECDA Survey Data (2009).

[209] NACE SP0169-2013, Control of External Corrosion on Underground or Submerged Metallic Piping Systems at 12.

activation. This would provide time for the operator to make adjustments and balance the cathodic protection system.

In addition, the proposed six-month repair timeframe under § 192.319 is inconsistent with § 192.465(d), which permits remediation "no later than the next monitoring interval in § 192.465 or within one year, whichever is less." PHMSA has not justified why the six-month remediation timeframe for pipelines with minimal corrosion risk (new segments or segments following repair or replacement) should be shorter than the one-year remediation time frame for pipelines with higher corrosion risk (segments where inadequate levels of cathodic protection are discovered through normal compliance inspections).

The three-month timeframe for surveys following backfill is both technically unsound and impractical. To ensure effective cathodic protection, an operator must allow time for moisture to settle into the soil and create electrical pathways to the pipe and for the backfill to settle around the pipe. Time also is required for a similar process to occur when a pipe is wrapped in rock shield to prevent coating damage during backfill.

4. Proposed § 192.935 (g)(2) should be limited to those pipe segments with known corrosion.

Proposed § 192.935(g)(2) would require that operators perform measures similar to those proposed in §§ 192.319(d) and 192.461(f) for pipe segments located in HCAs at least every seven years, even for pipe segments with no known corrosion history. If annual test station inspections reflect insufficient cathodic protection, an operator would be required to perform remediation within six months and perform a close interval survey on both sides of the affected test station to confirm the restoration of adequate corrosion control. Under proposed § 192.935(g) close interval surveys must be performed with the electric current interrupted. PHMSA states that it "has determined that some additional prescriptive preventive and mitigative measures are needed to assure that public safety is enhanced in HCAs and affords greater protections for HCAs." NPRM at 20,819.

PHMSA's authority to issue safety standards is constrained by the PSA's requirements and proscriptions. The PSA requires that a safety standard be "practicable," and be designed to meet gas pipeline safety needs and protect the environment.[210] Preventive and mitigative measures must be based on a risk assessment performed under § 192.917.[211] If a risk assessment indicates that a pipe segment does not have a known corrosion history, preventive and mitigative measures should not be required or should reflect the risk. PHMSA does not explain why this

[210] 49 U.S.C. § 60102(b)(1).

[211] 49 C.F.R. § 192.935(a).

proposed regulation should apply to all HCA pipeline segments, including those with no history or identified threat of external corrosion.

These prescriptive requirements could result in a number of significant adverse consequences. For example, requiring coating repairs on vintage pipelines where cathodic protection has been demonstrably effective for decades would impose huge costs with negligible real safety enhancements. Requiring an operator to perform a large number of excavations would have a negative impact on the environment and landowners. The associated pressure reductions to perform these excavations safely could have a negative impact on pipeline customers and the environment.

INGAA recommends that PHMSA modify proposed § 192.935(g) to require that operators conduct periodic indirect inspections only where a pipeline segment has a known history of corrosion. PHMSA should remove the requirement that current be interrupted when performing a close interval survey. Rather, an operator should be required to confirm compliance with the criteria set forth in Appendix D of Part 192. These criteria provide alternatives that do not entail interrupting cathodic protection.

C. INGAA's Proposed Regulatory Text Relating to External Corrosion

§ 192.319 Installation of pipe in a ditch.

[…]

(d) Promptly after a ditch for a steel onshore transmission line is backfilled**,** but not later than ~~three months~~ one year after placing the ~~pipeline~~ cathodic protection system in service, the operator must perform an indirect assessment (using an indirect method, such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) ~~to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). The operator must repair any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBμv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six months of the assessment.~~ Each operator of transmission pipelines must make and retain for the life of the pipeline records documenting the ~~coating~~ indirect assessment findings and ~~repairs~~ remedial actions.

§ 192.461 External corrosion control: Protective coating.

[…]

(f) Promptly, but no later than ~~three months~~ one year after backfill of an onshore transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), conduct an indirect assessment (using an indirect method, such as close interval survey, alternating current voltage gradient, direct current voltage gradient, or equivalent) ~~surveys to assess any coating damage to ensure integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). Remediate any coating damage classified as moderate or severe (voltage drop greater than 35% for DCVG or 50 dBµv for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within six months of the assessment.~~

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

(g) *External corrosion.* As an operator gains information about external corrosion, it must enhance its external corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to external corrosion. At a minimum, as part of this enhancement, operators must—

(1) Control electrical interference currents that can adversely affect cathodic protection as follows:

(i) As frequently as needed (such as when a pipelines is co-located within 1,000 feet of a ~~new or uprated~~ high voltage alternating current power lines greater than or equal to 69 kVA or electrical substations are co-located near the pipeline), but not to exceed every seven years, perform the following:

(A) Conduct an interference survey (at times when voltages are at the highest values for a time period of at least 24-hours) to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;

(B) Analyze the results of the survey to identify locations where interference currents are greater than or equal to 20 Amps per meter squared; and

(C) Take any remedial action needed within ~~six months~~ one year after completing the survey to protect the pipeline segment from deleterious current. Remedial action means the implementation of measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. ~~Any location with interference currents greater than 50 Amps per meter squared must be remediated. If any AC interference between 20 and 50 Amps per meter squared is not remediated, the operator must provide and document an engineering justification.~~

The following criteria shall be used to determine when remedial actions are required.

- *AC-induced corrosion does not occur at AC densities less than 20 A/m^2*

(1.9 A/ft^2). The operator shall monitor these locations per (1) (i) above.

- *AC corrosion is unpredictable for AC densities between 20 to 100 A/m^2 (1.9 to 9.3 A/ft^2). These locations require an engineering assessment to determine if remediation is required.*
- *AC corrosion occurs at current densities greater than 100 A/m^2 (9.3 A/ft^2)." These areas require mitigation.*

Any location that is determined to require mitigation must be mitigated to reduce the AC current density to less than 20 A/m^2

(2) Confirm the adequacy of external corrosion control through indirect assessment as follows:

(i) Periodically (as frequently as needed but at intervals not to exceed seven years) assess the adequacy of the cathodic protection system by conducting an indirect inspection through an indirect method such as close-interval survey~~, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG)~~. Alternatively, an operator may validate the effectiveness of the cathodic protection system by demonstrating that corrosion growth is not occurring on the pipeline. This may be accomplished with methods such as ILI run-to-run comparisons or ECDA.

(ii) Remediate any ~~damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP0502–2008 (incorporated by reference, see § 192.7)~~ cathodic protection levels below the required levels in Appendix D of this part according to § 192.564(d).

(iii) Integrate the results of the indirect assessment required under paragraph (g)(2)(i) of this section with the results of the most recent integrity assessment required by this subpart and promptly take any needed remedial actions no later than ~~6 months~~ one year after assessment finding.

(iv) Perform periodic assessments as follows:

(A) Conduct periodic close interval surveys ~~with current interrupted~~ to confirm compliance with Appendix D criteria to confirm voltage drops in association with integrity assessments under sections §§ 192.921 and 192.937 of this subpart.

(B) Locate pipe-to-soil test stations at half-mile intervals within each covered segment, ensuring at least one station is within each high consequence area, if practicable.

> (C) Integrate the results with those of the baseline and periodic assessments for integrity done under sections §§ 192.921 and 192.937 of this subpart.

D. Interference Currents

Section 192.473 of PHMSA's existing regulations requires that operators with pipelines subject to stray currents implement a program to minimize the detrimental effects of such currents. Proposed § 192.473(c) requires that such programs include interference surveys to detect the presence and level of any electrical stray current and to take remedial action no later than six months after completion of the survey.

For pipelines located in HCAs, proposed § 192.935(g)(1) would require that operators control electrical interference currents that can adversely affect cathodic protection by conducting interference surveys at least every seven years to detect the presence and level of any electrical current that could affect external corrosion. Operators would be required to take remedial action within six months of survey completion.

1. Interference surveys should be required only for pipelines subject to the threat of stray electric current and operators should be permitted one year to implement remediation measures.

PHMSA's existing regulations require that pipeline systems subjected to stray currents have a continuing program to minimize those current's detrimental effects. The NPRM adds requirements for interference surveys to detect the presence and level of interference, an analysis of the survey results and the impact on the effectiveness of cathodic protection, and implementation of remedial actions.

PHMSA should extend the implementation period from six months to one year. A six-month implementation period is not a sufficient period to accommodate the required activities. Determining the appropriate remediation measures requires an operator to obtain information, such as voltage and current, from the owner or operator of the stray AC/DC source. This information gathering process can be difficult and time-consuming because owners of the stray current source often consider this information as proprietary. Pipeline operators use this information to design appropriate remediation measures, which might include installing grounding systems or gradient control mats.

Recognizing the critical nature of the information needed for designing remediation measures, INGAA Foundation representatives have met with trade associations representing the owners of various AC and DC sources to identify ways to facilitate sharing of information critical to mitigation and remediation. Even though communication channels have been opened, obtaining the information remains a challenge. Adequate time is needed to accommodate these activities, as well as the time needed to perform required analyses to design the remediation measure. The INGAA Foundation commissioned a report on AC interference to present technical background, provide best practices and summary criteria for pipelines collocated with high voltage AC power lines.[212] The report addresses mitigation and monitoring, encroachment and construction and severity classification.

Installation of remediation measures also may require governmental approvals and permits. The installation of grounding systems and gradient control mats involves construction activities near the pipeline. If those activities occur outside of the pipeline right of way, an operator must perform the construction pursuant to an approval obtained under section 7 of the NGA and comply with applicable regulations, such as notification to nearby landowners, and environmental requirements, including the Clean Water Act, Clean Air Act, and Endangered Species Act.[213] If the construction meets a certain cost threshold, the operator must submit an application to FERC and provide 60 days notice for interested parties to submit comments or a protest. In that circumstance, construction can proceed only if no entity files a protest. If a protest is filed, the operator cannot perform the activity without express project-specific FERC approval. Even for activities that occur entirely on the pipeline right of way, requiring no specific FERC approval, the operator must provide notification of the activity to landowners located near the right of way, at least 45 days before the activity begins in certain circumstances.

If environmental permits are required before the remediation measure can be performed, many permitting agencies allow construction activities only during specified times of the year because of environmental impact, wildlife mating and habitat concerns. In some regions, construction and close-interval surveys can be performed only at certain times of the year because of snow cover or frozen ground.

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[212] DNV GL, Criteria for Pipelines Co-Existing with Electric Power Lines, INGAA Foundation Report No. 2015-04, (Oct. 2015).

[213] *Revisions to Auxiliary Installations, Replacement Facilities, and Siting and Maintenance Regulations,* Order No. 790, 2008-2013 FERC Stats. & Regs. ¶ 31,351 (2013), *order on reh'g,* Order No. 790-A, III FERC Stats & Regs, ¶ 31,361 (2014), *order on clarif.*, III FERC Stats. & Regs. ¶ 31,371 (2015); 18 C.F.R. § 2.55 (2016) (auxiliary and replacement facilities); 18 C.F.R. Subpart F (2016) (construction blanket certificate regulations).

2. INGAA's Proposed Regulatory Text Relating to Preventive and Mitigative Measures

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

(g) *External corrosion.* As an operator gains information about external corrosion, it must enhance its external corrosion management program, as required under subpart I of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to external corrosion. At a minimum, as part of this enhancement, operators must—

(1) Control electrical interference currents that can adversely affect cathodic protection as follows:

(i) As frequently as needed (such as when a pipelines is co-located within 1,000 feet of a ~~new or uprated~~ high voltage alternating current power lines greater than or equal to 69 kVA or electrical substations are co-located near the pipeline), but not to exceed every seven years, perform the following:

(A) Conduct an interference survey (at times when voltages are at the highest values for a time period of at least 24-hours) to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;

(B) Analyze the results of the survey to identify locations where interference currents are greater than or equal to 20 Amps per meter squared; and

(C) Take any remedial action needed within ~~six months~~ one year after completing the survey to protect the pipeline segment from deleterious current. Remedial action means the implementation of measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. ~~Any location with interference currents greater than 50 Amps per meter squared must be remediated. If any AC interference between 20 and 50 Amps per meter squared is not remediated, the operator must provide and document an engineering justification.~~

The following criteria shall be used to determine when remedial actions are required.

- *AC-induced corrosion does not occur at AC densities less than 20 A/m^2 (1.9 A/ft^2). The operator shall monitor these locations per (1) (i) above.*
- *AC corrosion is unpredictable for AC densities between 20 to 100 A/m^2 (1.9 to 9.3 A/ft^2). These locations require an engineering assessment to determine if remediation is required.*
- *AC corrosion occurs at current densities greater than 100 A/m^2 (9.3 A/ft^2)." These areas require mitigation.*

Any location that is determined to require mitigation must be mitigated to reduce the AC current density to less than 20 A/m^2

§ 192.473 External corrosion control: Interference currents.

[…]

(c) For onshore gas transmission pipelines, the program required by paragraph (a) must include:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be ~~taken~~ conducted on a periodic basis ~~including,~~ when potential monitoring indicates a significant increase in stray current, or new potential stray current sources are introduced, such as ~~there are current flow increases over pipeline segment grounding design, from any~~ co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could ~~impact the effectiveness of cathodic protection~~ cause significant corrosion; and

(3) Implementation of remedial actions to protect the pipeline segment from detrimental interference currents promptly but no later than ~~six months~~ one year after completion of the survey, or as soon as practicable after obtaining necessary permits.

(4) When pipelines are co-located within 1,000 feet of a high voltage alternating current power lines greater than or equal to 69 kVA or electrical substations are co-located near the pipeline), but not to exceed every seven years, perform the following:

(A) Conduct an interference survey (at times when voltages are at the highest values for a time period of at least 24-hours) to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;

(B) Analyze the results of the survey to identify locations where interference currents are greater than or equal to 20 Amps per meter squared; and

(C) Take any remedial action needed within one year after completing the survey to protect the pipeline segment from interference currents. Remedial action means the implementation of measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. The following criteria shall be used to determine when remedial actions are required.

- *AC-induced corrosion does not occur at AC densities less than 20 A/m^2 (1.9 A/ft^2). The operator shall monitor these locations per (1) (i) above.*
- *AC corrosion is unpredictable for AC densities between 20 to 100 A/m^2 (1.9 to 9.3 A/ft^2). These locations require an engineering assessment to determine if remediation is required.*
- *AC corrosion occurs at current densities greater than 100 A/m^2 (9.3 A/ft^2).” These*

areas require mitigation.

Any location that is determined to require mitigation must be mitigated to reduce the AC current density to less than 20 A/m^2

E. Remedial Actions Under Proposed § 192.465

1. PHMSA should allow exceptions to the one-year deadline proposed in § 192.465.

Proposed modifications to § 192.465(d) would require that external corrosion remediation measures be completed promptly, but no later than the next monitoring interval or within one year, whichever is less. The remediation activities contemplated could involve installation of linear anodes, placement of a new ground bed, or installation of an additional rectifier.

As noted above, if installation of these facilities require construction activities outside of the pipeline right of way, an operator may require approval under NGA § 7. Other governmental and environmental permits also could be required. Under § 7, an operator must notify nearby landowners a minimum of 45 days in advance, and comply with numerous environmental requirements.[214] If the construction meets a certain cost threshold, the operator must notify FERC and other interested entities and, if a protest is filed, obtain a project-specific authorization. In addition, environmental permit restrictions and weather issues can limit construction activities to certain times of the year.

INGAA requests that PHMSA provide flexibility in compliance timelines to accommodate delays in completing remedial action resulting from delays in obtaining governmental authorizations and permits.

2. The requirement for close interval surveys following a low reading at a test station should be limited.

Proposed § 192.465(f) provides that, if any annual test station reading indicates that cathodic protection is below required levels, an operator must conduct a close interval survey in both directions from the test station, where practical, based on geographical, technical or safety reasons. This proposed requirement would appear to apply even if low cathodic protection has been caused by very common and easily addressed problems such as an electrical short to an adjacent foreign structure, rectifier malfunction, or simply an interruption in power input to a rectifier unit. Requiring a close interval survey in these circumstances is not necessary and would impose a significant burden that is not commensurate with the resulting safety benefit.

[214] 18 C.F.R. § 157.203(d) (2016) (landowner notification for construction under a blanket certificate); 18 C.F.R. § 157.206 (2016) (environmental compliance for blanket certificate activity).

PHMSA should not require a close interval survey if the adequacy of cathodic protection levels can be determined using other above ground survey methods. A close-interval survey will be performed to confirm restoration of adequate cathodic protection upon completing. PHMSA should acknowledge these exceptions in its new close-interval survey requirements.

3. INGAA's Proposed Regulatory Text §192.465

§ 192.465 External corrosion control: Monitoring and remediation

[…]

(d) Each operator ~~shall take~~ must promptly ~~remedial action to~~ correct any deficiencies indicated by the ~~monitoring.~~ inspection and testing provided in paragraphs (a), (b) and (c) of this section. Remedial action must be completed promptly, but no later than the next monitoring interval in § 192.465 or within one year, whichever is less~~.~~, or as soon as practicable after obtaining necessary permits.

[…]

(f) For onshore transmission lines, where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in Appendix D of this part, the operator must determine the extent of the area with inadequate cathodic protection. Close interval surveys must be conducted in both directions from the test station with a low cathodic protection (CP) reading at a minimum of approximately five foot intervals. Close interval surveys must be conducted, where practical based upon geographical, technical, or safety reasons. Close interval surveys required by this part must be completed with the protective current interrupted unless it is impractical to do so for technical or safety reasons. Remediation of areas with insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline must be performed in accordance with paragraph (d) of this section. The operator must confirm restoration of adequate cathodic protection by close interval survey over the entire area. Close interval surveys are not required in instances where low potentials are measured for electrical short to an adjacent foreign structure, rectifier connection or power sources. The operator may presume that the preponderance of pipe between test stations does not meet the required cathodic protection levels. Operators can perform a close interval survey following the remedial measures to confirm restoration of adequate cathodic protection.

F. PHMSA should amend its Appendix D to reflect the same criteria used in the hazardous liquid pipeline safety regulations.

PHMSA proposes to modify Part 192, Appendix D (Criteria for Cathodic Protection and Determination of Measurements) to align the criteria with NACE SP0169 ("Control of External Corrosion on Underground or Submerged Metallic Piping Systems"). NPRM at 20,782. Appendix D to Part 192 lists criteria for the cathodic protection of steel, cast iron & ductile pipelines. PHMSA proposes to modify (1) a negative 0.85 volts direct current, taking voltage drop (loss of voltage due to soil resistance) into account with a saturated copper-copper sulfate half-cell, and (2) a negative 100 millivolt polarization shift. NPRM at 20,853. PHMSA has not demonstrated a basis for the proposed modification. These established criteria are the primary methods operators in the gas industry have used for decades to confirm adequate cathodic protection.

In Section II of Appendix D, "Interpretation of voltage measurement," PHMSA states that "structure-to-electrolyte potential measurements must be made utilizing measurement techniques that will *minimize* voltage (IR) drops other than those across the structure electrolyte boundary. All voltage (IR) drops other than those across the structure electrolyte boundary will be differentiated, such that the resulting measurement accurately reflects the structure-to-electrolyte potential." NPRM at 20,853. It is unclear how the references to "minimizing IR drops" and "differentiating IR drops" in the proposed language is different than "considering" IR drops, which is the language in paragraphs 6.2 and 6.3 of NACE SP 0169, which is in turn incorporated by reference in 49 C.F.R. § 195.571. INGAA proposes that Appendix D be made consistent with § 195.571 and paragraphs 6.2 and 6.3 of NACE SP 0169.

In Section III, PHMSA states, that:

> [t]he polarization voltage shift must be determined *by interrupting the protective current and measuring the polarization decay*. When the current is initially interrupted, an immediate voltage shift occurs, often referred to as an *instant off potential*. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay.

NPRM at 20,853 (emphasis added). INGAA has concern with Section III. PHMSA fails to acknowledge that not all cathodic protection systems can be interrupted, such as sacrificial anodes connected directly to the pipeline – which was a common practice. Every industry standard (including all versions of NACE SP0169 Control of External Corrosion on Underground or Submerged Metallic Piping Systems, dating from 1969 to present) provides for other methods of addressing IR drop, including using cathodic protection coupons or prior measurements to determine the magnitude of IR drop. PHMSA's criteria in Appendix D, Section I, for determining the adequacy of cathodic protection is too narrow. PHMSA should add "Cathodic protection required by this Subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE SP 0169." to I.A. in Appendix D. This is consistent with the currently effective provisions of § 195.571.

PHMSA's proposed revisions to the existing Part 192 Appendix D II. would not improve the guidance on how to interpret IR drop or better align with the criteria for cathodic protection in NACE SP0169, Control of External Corrosion on Underground or Submerged Metallic Piping Systems. Instead, PHMSA's proposed revisions would create more confusion and uncertainty in how to interpret the regulations by creating a new undefined process of "differentiating IR drops." It is unclear how "minimizing IR drops" differs from "considering" IR drops. PHMSA should retain the existing language of in Part 192 Appendix D II because "considering" IR drops is defined clearly in the NACE standard, which the gas and liquid pipeline industries have adopted and follow.

Appendix D to Part 192 – Criteria for Cathodic Protection and Determination Measurements

I. *Criteria for cathodic protection—*

A. *Steel, cast iron, and ductile iron structures.*

Cathodic protection required by this Subpart must comply with one or more of the applicable criteria and other considerations for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE SP 0169:

(1) A negative (cathodic) voltage across the structure electrolyte boundary of at least 0.85 volt, with reference to a saturated copper-copper sulfate reference electrode, often referred to as a half cell. Determination of this voltage must be made ~~with the protective current applied, and~~ in accordance with sections II and IV of this appendix.

~~(2)~~ A minimum negative (cathodic) polarization voltage shift of at least ~~300~~ 100 millivolts. This polarization voltage shift ~~must~~ should be determined ~~Determination of this voltage shift must be made with the protective current applied, and~~ in accordance with sections II and IV of this appendix. ~~This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.~~

~~(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.~~

~~(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.~~

~~(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.~~

B. *Aluminum structures.*

(1) Except as provided in paragraphs (2) and (3) ~~and (4)~~ of this paragraph, a minimum negative (cathodic) polarization voltage shift of ~~150~~ 100 millivolts~~,~~ ~~produced by the application of protective current.~~ ~~The~~ This polarization voltage shift must be determined in accordance with sections ~~II and IV~~ III and IV of this appendix.

~~(2) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.~~

(2) Notwithstanding the alternative minimum criteria in paragraph~~s~~ (1) ~~and (2) of this paragraph~~, if aluminum~~, if~~ is cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate reference electrode ~~half cell,~~ in accordance with section ~~IV~~II of this appendix, the aluminum may suffer corrosion resulting from the build-up of alkali on the metal surface ~~and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the build-up of alkali on the metal surface.~~ A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(3) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures.* A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. *Metals of different anodic potentials.* A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (2) and (3) ~~and (4)~~ of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement.* Structure-to-electrolyte potential measurements must be made utilizing measurement techniques that will minimize voltage (IR) drops other than those across the structure-electrolyte boundary. ~~must be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of section I of this appendix.~~ All voltage (IR) drops other than those across the structure electrolyte boundary will be differentiated, such that the resulting measurement accurately reflects the structure-to-electrolyte potential.

III. *Determination of polarization voltage shift.* The polarization voltage shift ~~must~~ can be determined by methods identified in NACE SP0207-2007, Section 5, such as interrupting the protective current and measuring the polarization decay. On systems where the current can be interrupted, ~~W~~when the current is initially interrupted, an immediate voltage shift occurs which is often referred to as IR drop ~~an instant off potential~~. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A(2), B(1), and C of section I of this appendix.

IV. *Reference electrodes (half cells).*

A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate reference electrode ~~half cell~~ contacting the electrolyte.

B. Other standard reference ~~half cells~~ electrodes may be substituted for the saturated cooper-copper sulfate ~~half cell~~ electrode. Two commonly used reference ~~half cells~~ electrodes are listed below along with their voltage equivalent to −0.85 volt as referred to a saturated copper-copper sulfate ~~half cell~~ reference electrode:

(1) Saturated KCl calomel half cell: −0.78 volt.

(2) Silver-silver chloride ~~half cell~~ reference electrode used in sea water: −0.80 volt.

C. In addition to the standard reference electrodes ~~half cells~~, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate ~~half cell~~ reference electrode if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate ~~half cell~~ reference electrode is established.

XII. Subpart O – Improving IM

A. Section 192.935(a) Must Be Clarified To State That Operators Are Not Required To Implement All Listed Potential Preventive And Mitigation Measures.

Section 192.935 sets forth preventive and mitigative requirements applicable to pipe segments located in HCAs. The proposed revisions to subsection (a) would delete existing language that provides operators the discretion to "base the additional measures on the threats the operator has identified."[215] The proposed regulatory text also adds the following language:

> Such additional measures must be based on the risk analysis required by § 192.917, and *must* include, but are not limited to . . . replacing pipe segments with pipe of heavier wall thickness or higher strength.[216]

The combination of this additional language and the deleted text creates confusion. Operators are required to apply preventive and mitigative measures to covered pipe segments based on the threats posed to the particular pipe segment. This concept appears to be preserved by the proposed language requiring that additional measures be based on a risk analysis. However, language appearing to mandate an inclusive list of preventive and mitigative measures could lead to the absurd conclusion that an operator must implement all of the listed measures, including replacing pipe segments with heavier wall pipe, in all circumstances.

To avoid confusion and to be consistent with the purpose of preventive and mitigative measures, INGAA proposes that the final rule be clarified so that the list of additional preventive and mitigative measures included in § 192.935(a) is understood to be a list of examples an operator in an HCA must consider. PHMSA must clarify that an operator is not required to implement each of them.

INGAA's Proposed Regulatory Text Related to § 192.935(a)

> (a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. ~~An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 5, a risk analysis of its pipeline to identify~~

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[215] Provisions of § 192.935(a) apply general requirements to al integrity threats and not just internal corrosion. The comments on this section apply more broadly to the other integrity threats including external corrosion, stress corrosion cracking, and mechanical damage among others.

[216] Proposed § 192.935(a) (emphasis added).

~~additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to,~~ Such additional measures must be based on the risk analyses required by § 192.917, and ~~must~~ may include, but are not limited to:

B. § 192.917: INGAA Proposes Certain Technically-Based Modifications to Improve Operators' Ability to Implement Integrity Management Regulations.

Section 192.917 addresses how an operator identifies potential threats to pipeline integrity and uses the threat identification in its integrity program. While the NPRM explains the proposed rule §192.917 changes as clarifications, some of these changes have effectively expanded the rule beyond its original scope. INGAA agrees with the intent of the proposed PHMSA changes, but the rule must allow operators to apply the right tools in the right places. INGAA supports the continual improvement of integrity management, and will demonstrate in these comments that certain aspects of the proposed rule would benefit from modifications that promote pipeline safety.

The NPRM provides no technical explanation or justification for certain proposed changes to § 192.917. The NPRM relies almost solely on the NTSB recommendations to PG&E related to the specific conditions of the San Bruno accident. NPRM at 20,816. The NPRM also notes that PHMSA held a workshop on July 21, 2011 "to address perceived shortcomings in the implementation of integrity management risk assessment processes and the information and data analysis (including records) upon which such risk assessments are based." NPRM at 20,816. The NPRM does not explain the specific reasons and technical basis for its determination "that additional clarification and specificity is needed for existing performance-based rules." NPRM at 20,816. As discussed in specific examples below, PHMSA has not adequately justified and supported the changes to proposed §192.917.[217] The perfunctory reliance on NTSB recommendations fails to identify which NTSB recommendations are relevant or how they are relevant, explain the findings of the July 2011 workshop, or explain how these establish the existence of a problem or why the proposed revisions to section 192.917 provide an appropriate solution.[218] PHMSA has failed to draw "a rational connection between the facts found and the choice made."[219] PHMSA also has not demonstrated that it considered "the statutorily mandated factor[s]" in adopting this proposed revised safety standard.[220] Finally, as discussed in more

[217] The lack of technical support and justification is not limited to these examples.

[218] *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 839, 843 (D.C. Cir. 2006) (vacating agency rule because record evidence did not support existence of the problem the rule purported to address).

[219] *Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines v. United States*, 371 U.S. 156, 168 (1962)) (vacating as arbitrary and capricious final rule that rescinded regulations without adequate explanation).

[220] *Owner-Operator Indep. Drivers Ass'n v. FMCSA*, 656 F.3d 580, 589 (7th Cir. 2011) (vacating rule because agency failed to consider an issue it was statutorily required to address), *Pub. Citizen v. FMCSA*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) (finding that agency's failure to consider statutory factor constituted a failure to consider an

detail in Section XV (PHMSA's Cost Benefit Analysis) and Section XVI (Environmental Assessment Analysis), PHMSA has failed to properly assess the cost and environmental impact of the expanded rule scope under Subpart O. INGAA proposes certain technically-based modifications to ensure that the proposed rule actually improves integrity management.

1. § 192.917(b): Proposed Modifications to Data Gathering and Integration Requirements Will Create Confusion and Are Not Technically Supported.

Existing § 192.917(b) addresses how an operator gathers data and integrates such data into its integrity management plan. Existing subsection (b) requires an operator to follow the requirements in ASME/ANSI B31.8S, which it incorporates by reference. Existing subsection (b) also requires an operator to consider certain records, history, and conditions of both the covered segment and similar non-covered segments. The NPRM proposes to modify the existing language of subsection (b) and add subparts (b)(1) through (b)(4). The proposed changes will cause confusion and should be revised.

a. The Proposal to Expand the Integrity Management Regulations to Require That Operators Analyze Data for Non-Covered Segments Is Not Adequately Explained

The NPRM is an expansion of subsection (b), rather than a clarification of the existing rule. The first paragraph of proposed subsection (b) states that operators "must analyze" both covered and similar non-covered segments under ASME/ANSI B31.8S and adds a new list of defined elements in subpart (b)(1) which reiterate the requirements of ASME/ANSI B31.8S. By contrast, under the existing rule operators are required to *consider* certain history, records, and conditions of similar non-covered segments. Without justification, the proposed language requires the application of ASME/ANSI B31.8S to similar non-covered segments, although the data required by ASME/ANSI B31.8S may be unavailable for these segments. In particular, PHMSA has added, without explanation, the requirement that the operator "verify, validate" the data gathered. This expands the previously discussed TVC-style standards into a new area where previously they have not been required.

INGAA proposes to modify the proposed first paragraph of subsection (b) to retain the requirement that operators "consider" similar non-covered segments, rather than mandate that all aspects of ASME/ANSI B31.8S be applied to similar non-covered segments. Application of ASME/ANSI B31.8S should be required only for covered segments.

b. The Proposal to List ASME/ANSI B31.8S Data Sets in the Regulation Is Confusing.

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important aspect of the problem).

Proposed subpart (b)(1) codifies certain parts of ASME/ANSI B31.8S related to data gathering and integration by incorporating a detailed list of data sets that operators must collect in subsection (b)(1), while also keeping the existing incorporation by reference. NPRM at 20,816; 20,840-41. PHMSA acknowledges that ASME/ANSI B31.8S is already "invoked by reference," but asserts that "these important aspects of integrity management will receive greater emphasis and awareness if incorporated directly into the rule of the text." NPRM at 20, 817.

Placing language from ASME/ANSI B31.8S into the regulation is duplicative and confusing. There are discrepancies between the language in ASME/ANSI B31.8S and the proposed regulatory text. For example, under ASME/ANSI B31.8S, "CP (cathodic protection) system performance" is listed. Likewise, under proposed (b)(1)(xxii), "CP system performance" is also listed. But under § 192.917 (b)(1)(xxiv)(B)-(E) (the title of which is "Pipe operational and maintenance inspection reports, including but not limited to:"), PHMSA also proposes to list: close interval survey (CIS) and electrical survey results; cathodic protection (CP) rectifier readings; CP test point survey readings and locations; and AC/DC and foreign structure interference surveys. These items would appear to already be covered by "CP system performance" and are not individually set forth in ASME/ANSI B31.8S. It is unclear what the purpose is in listing these additional items in the manner proposed. If it is intended to expand the requirements of subsection (b), PHMSA has provided no basis for such an expansion or clear guidance on what activities industry is expected to perform in order to evaluate and comply with such a rule, nor has PHMSA properly assessed the significant cost impact this will have on operators, as discussed further in Section XVI (Cost Analysis). The table below shows the discrepancies between ASME/ANSI B31.8S, Section 4, Table 1, and the proposed subpart (b)(1) list.

Table B

ASME/ANSI B31.8S, Section 4, Table 1		**PHMSA's Proposed § 192.917(b)(1)**
Attribute Data:	Pipe wall thickness	Pipe Diameter, wall thickness, grade, seam type and joint factor
	Diameter Seam type and joint factor	See Pipe wall thickness
	Manufacturer	Manufacturer and manufacturing date, including manufacturing data and records
	Manufacturing date	See Manufacturer
	Material properties	Material Properties including, but not limited to diameter, wall thickness, grade, seam type, hardness, toughness, hard spots and chemical composition
	Equipment properties	Same
Construction:	Year of installation	Same
	Bending method	Same

ASME/ANSI B31.8S, Section 4, Table 1		**PHMSA's Proposed § 192.917(b)(1)**
	Joining method, process and inspection results	Same
	Depth of cover	Depth of cover surveys including stream and river crossings, navigable waterways and beach approaches
	Crossings/ casings	Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;
	Pressure test	Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;
	Field coating methods	Pipe coating methods (both manufactured and field applied) including method or process used to apply girth weld coating, inspection reports, and coating repairs;
	Soil, backfill	Same
	Inspection reports	Construction inspection reports, including but not limited to: (A) Girth weld non-destructive examinations; (B) Post backfill coating surveys; (C) Coating inspection ("jeeping") reports;
	Cathodic protection installed	Cathodic protection installed, including but not limited to type and location
	Coating type	Same
Operational	Gas quality	Same
	Flow rate	Same
	Normal maximum and minimum operating pressures	Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);
	Leak/failure history	Leak and failure history including any in-service ruptures or leaks from incident reports, abnormal operations, safety related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences;
	Coating condition	Same
	CP (cathodic protection) system	Same

ASME/ANSI B31.8S, Section 4, Table 1		PHMSA's Proposed § 192.917(b)(1)
	performance	
	Pipe wall temperature	Same
	Pipe inspection reports	Pipe operational and maintenance inspection reports, including but not limited to: (A) Data gathered through integrity assessments required under this part, including but not limited to in-line inspections, pressure tests, direct assessment, guided wave ultrasonic testing, or other methods; (B) Close interval survey (CIS) and electrical survey results; (C) Cathodic protection (CP) rectifier readings; (D) CP test point survey readings and locations; (E) AC/DC and foreign structure interference surveys; (F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including but not limited to direct current voltage gradient or alternating current voltage gradient inspections; (G) Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe coating condition, see § 192.459), including the results of any non-destructive examinations of the pipe, seam or girth weld, i.e., , , bell hole inspections; (H) Stress corrosion cracking (SCC) excavations and findings; (I) Selective seam weld corrosion (SSWC) excavations and findings; (J) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;
	OD/ID corrosion monitoring	Same
	Pressure fluctuations	Operating pressure history and pressure fluctuations, including analysis of effects of pressure cycling and instances

ASME/ANSI B31.8S, Section 4, Table 1		PHMSA's Proposed § 192.917(b)(1)
		of exceeding MAOP by any amount;
	Regulator/relief performance	Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;
	Encroachments	Encroachments and right-of-way activity, including but not limited to, one-call data, pipe exposures resulting from encroachments, and excavation activities due to development or planned development along the pipeline
	Repairs Vandalism	Repairs; Vandalism;
	External forces	Same; and Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area;
Inspection	Pressure tests	See Pipe Inspection
	In-line inspections	See Pipe Inspection
	Geometry tool inspections	See Pipe Inspection
	Bell hole inspections	See Pipe Inspection
	CP inspections (CIS)	See Pipe Inspection
	Coating condition inspections (DCVG)	See Pipe Inspection
	Audits and reviews	Same
		Class Location
		Industry experience for incident, leak and failure history;
		Aerial photography;
		Other pertinent information derived from operations and maintenance activities and any additional tests, inspections, surveys, patrols, or monitoring required under this Part.

INGAA proposes to remove unnecessary or unobtainable data elements from the detailed listing. INGAA's proposal is appropriate because ASME/ANSI B31.8S provides clear guidance to operators with a comprehensive listing of data elements to utilize for each threat.

INGAA has demonstrated that the proposed language in the first paragraph of subsection (b) regarding similar non-covered segments is not justified from either a technical or a cost perspective. Many of data elements required by ASME/ANSI B31.8S are not available for legacy pipelines, which can fall into the category of similar non-covered segments. The duplicative and expanded list added in subpart (b)(1) does not increase the effectiveness or the value of the risk assessment requirements already incorporated by reference to ASME/ANSI B31.8S. INGAA's proposed language should be substituted for PHMSA's proposal.

c. PHMSA Should Provide a Timeline for Developing Plans for Gathering and Integrating Additional Data.

PHMSA does not provide a timeline for complying with the extensive proposed changes, nor does it explain whether these proposed requirements apply to legacy and newly-constructed pipelines alike. Given the potentially broad expansion of the subsection (b)(1) elements to additional non-covered segments, operators must be provided sufficient time to comply with the new rule. The failure to specify a timeline is inconsistent with other portions of the proposed rule, such as § 192.624(b), which provides operators a timeline to develop a plan and then gather the required information. Considering the fact that certain data elements under subpart (b)(1) overlap with data elements under § 192.624(b), PHMSA's failure to set forth a timeline for subpart (b)(1) data elements creates inconsistencies and conflicts within the rule. INGAA proposes a timeline consistent with § 192.624(b) for collecting any data that is newly identified. This is appropriate because it provides sufficient time for operators to comply with the proposed rule.

d. PHMSA Should Clarify Certain Aspects of the Data Integration Provisions.

Proposed § 192.917(b)(2) and (3) would require that the data and information an operator integrates into its threat identification program must be "objective, traceable, verified, and validated to the maximum extent practicable."[221] PHMSA does not explain this new standard, stating merely that PHMSA is proposing "to explicitly require that operators integrate analyzed information, and ensure data be verified and validated . . . to the maximum extent possible." NPRM at 20,816. PHMSA acknowledges that objective, documented data is not always available or obtainable and allows for the use of subject matters experts ("SMEs"). To the degree that subjective data from SMEs must be used, PHMSA proposes to "require that an operator's program include specific features to compensate for subject matter expert bias." NPRM at 20,816. Proposed § 192.917(b)(3) requires further that an operator "identify and analyze special relationships among anomalous information." The proposed regulation states further that storing this information in a common location including a GIS by itself is insufficient. INGAA agrees that risk assessment and data collection should continue to improve, and proposes certain changes to PHMSA's proposed rule to enhance this effort to improve risk assessment and data collection.

[221] Proposed § 192.917(b)(2).

Proposed (b)(2) applies another variation of the TVC standard, "objective, traceable, verified, and validated," that has not previously been used for the type of data covered under §192.917. INGAA proposes to modify this standard to be more consistent with the type of data that is relevant for risk assessment. INGAA proposes to remove the TVC-style standard from subpart (b)(2) and instead require that operators use "objective and validated information and data inputs." This is a critical distinction because TVC requirements were initially developed in relation to MAOP, which is traceable, but do not make sense for a number of the data elements under subsection (b). This includes, but is not limited to, such things as vandalism (*see* § 192.917(b)(1)(xxx)), audits and (1)(xxxii), and aerial photography (*see* § 192.917(b)(1)(xxxiv)).

INGAA's proposal for subpart (b)(2) is appropriate because TVC data may not be applicable to many of the risk data elements. With respect to missing data, INGAA's proposal ensures safety by requiring an operator to implement adequate control measures. This allows an operator to utilize a risk-based approach to prioritize resources to the highest risk issues and assets.

While (b)(2) allows for input from SMEs when the TVC-style data is not available, PHMSA's proposal restricts this input by requiring that an operator "employ measures to adequately correct any bias in SME input," and lists specific measures to be taken. PHMSA does not explain or define what SME bias is, nor does it explain or provide support for how such alleged bias has created a safety risk to pipeline integrity.

INGAA proposes to delete the undefined references to "SME bias" and the specific list in subpart (b)(2) setting forth the measures that must be taken to correct SME bias. Rather than utilize the undefined and confusing new element of "SME bias," the INGAA proposal would require operators to employ adequate controls, such as peer review and external SMEs, to ensure consistency and accuracy of information PHMSA already has provided clear guidance in § 192.915 for qualifying SMEs.

INGAA also proposes removing subpart (b)(2)'s documentation requirement for SMEs because this is redundant to pipeline recordkeeping already required by Subpart O of the proposed rule. Instead, INGAA's proposal also allows for use of conservative assumptions where data is not available and for the development of a plan to gather and address the required information where practical. This activity occurs prior to collecting input from SMEs and is critical to managing missing data. This approach is consistent with the preamble to § 192.917, where PHMSA recognized that "objective, documented data is not always available or obtainable." NPRM at 20,816. This is also expressly addressed in ASME/ANSI B31.8S, Section 5.7e and Sections A1.2, A2.2, A3.2, A4.2, A5.2, A6.2, and A9.2: "Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher."

Proposed § 192.917(b)(3) requires operators to "[i]dentify and analyze spatial relationships among anomalous information," and states that storing information in a geographic information system (GIS) alone is not sufficient. PHMSA's intent is consistent with the intent of ASME/ANSI B31.8S, Section 4.5. INGAA agrees and recognizes the importance of data integration. INGAA members created guidance on integration of data and consideration of interacting threats in 2012.[222]

INGAA's proposal strengthens the proposed integrity management rules by providing clear guidelines that are appropriate for the type of data at issue. It better aligns operator resources where such resources are needed most. INGAA has demonstrated that the NPRM's proposed language in subparts (b)(2) and (b)(3) is not technically based or supported. The duplicative language in subpart (b)(3) is potentially confusing and does not improve either the effectiveness or the value of risk assessment requirements already incorporated by reference to ASME/ANSI B31.8S. For these reasons, INGAA's proposed language above should be used in lieu of the NPRM changes.

2. PHMSA Should Clarify Confusing Language With Respect To Interacting Threats

PHMSA explains that subpart § 192.917 (c) is attempting to

> clarify the performance-based risk assessment aspects of the IM rule to specify that operators perform risk assessments that are adequate to evaluate the effects of interacting threats; determine additional preventive and mitigative measures needed, analyze how a potential failure could affect high consequence areas, including the consequences of the entire worst-case incident scenario from initial failure to incident termination; identify the contribution to risk of each risk factor, or each unique combination of risk factors that interact or simultaneously contribute to risk at a common location, account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and evaluate risk reduction associated with candidate risk reduction activities such as preventive and mitigative measures.

NPRM at 20,816-817. PHMSA also proposes performance-based language to require that operators validate their risk models in light of incident, leak, and failure history and other historical information. NPRM at 20,817.

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[222] INGAA, Interacting Threats to Pipeline Integrity – Defined and Explained (Apr. 23, 2013), http://www.ingaa.org/File.aspx?id=20210; Northeast Gas Ass'n, Incorporating Interactive Threats in Kiefner/NYGAS and Other Risk Models, http://www.nysearch.org/tech_briefs/T-768_InteractiveThreats_TBv2011_012412.pdf.

The NPRM states that its proposal is a response to NTSB recommendation P–11–18, but provides no other support, other than to state that these features are duplicative of ASME/ANSI B31.8S, which is incorporated by reference. As with subsection §192.917(b)(1), PHMSA asserts that certain important aspects of ASME/ANSI B31.8S "will receive greater emphasis and awareness if incorporated directly into the rule text." NPRM at 20,817. The NPRM provides no explanation for its conclusion and no explanation of how the agency complied with the PSA's requirements when adopting a safety standard.[223]

INGAA agrees that integrity management should improve continually and proposes changes to provide additional clarity and precision in light of the redundant nature of subsection (c) when compared with ASME/ANSI B31.8S. The redundant reference to interacting threats that occurs in the first paragraph of subsection (c) should be removed since it is captured in more detail in subpart (c)(2). Also, the treatment of interacting threats under ASME/ANSI B31.8S is built into PHMSA's enforcement protocols, providing an effective enforcement methodology.[224] The Protocols at C.02 discuss the consideration of interactive threats by incorporating by reference ASME/ANSI B31.8S-2004, Section 2.2. INGAA also proposes to delete references to worst-case scenarios, since this language is already covered in the definition of Potential Impact Radius and High Consequence Areas, as well as other consequence factors in the risk model. These references are confusing, and PHMSA has not explained how this language is different from what is already required under the rule under Potential Impact Radius analysis. INGAA's proposed changes remove these confusing redundancies, while continuing to ground the proposed rules in ASME/ANSI B31.8S, which is recognized as the appropriate technical standard not only by the NPRM but by PHMSA's enforcement protocols as well. For example, the Protocols at C.01.c. discuss the consideration of interactive threats by incorporating by reference ASME/ANSI B31.8S-2004, Section 2.2.[225] INGAA's proposal will continue to provide this strong regulatory framework grounded in ASME/ANSI B31.8S.

INGAA has demonstrated that PHMSA's proposed language in subsection (c) is duplicative and potentially confusing. INGAA's proposal is appropriate because it removes redundancies that may result in a confusing rule. Clarity will enhance safety and compliance by ensuring that the new safety rules are clearly understood and implemented by the operators. For these reasons, INGAA's proposed language should be used in lieu of PHMSA's proposal.

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[223] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (citing *Burlington Truck Line, Inc. v. U.S.*, 371 U.S. 156, 168 (1962) (vacating agency's rescission of regulation without adequate explanation); *Owner-Operator Indep. Drivers Ass'n v. FMCSA*, 656 F.3d 580 (7th Cir. 2011) (vacating rule because agency failed to consider an issue it was statutorily required to address).

[224] PHMSA Gas Integrity Management Inspection Manual, Inspection Protocols with Results Forms (August 2013) ("Protocols").

[225] PHMSA Gas Integrity Management Inspection Manual, Inspection Protocols with Results Forms (August 2013).

3. PHMSA Should Remove References to Fracture Mechanics Modeling and Annual Cyclic Fatigue Analysis.

Subsection (e) addresses actions that must be taken to address particular threats. PHMSA's proposal provides for several improvements to integrity management, including increased diligence related to cyclic fatigue and manufacturing- and construction-related defects. INGAA supports PHMSA's goals, but proposes technically-based modifications to balance better the NPRM's goal of allowing "operators to make risk-based decisions on where to allocate their maintenance and repair resources." NPRM at 20,724.

PHMSA's proposed changes to subpart (e)(2) add language requiring (1) fracture mechanics modeling in accordance with § 192.624(d);[226] and (2) the annual performance of cyclic fatigue analysis.[227] The NPRM does not appear to provide any technical support for these changes.

The addition of fracture mechanics modeling in accordance with § 192.624(d) is problematic because § 192.624(d) addresses fracture mechanics for a particular pipeline segment and cracking situation. That is not the case with cyclic fatigue analysis, which evaluates pressure fluctuations to see if cyclic fatigue is an applicable threat on the pipeline. The existing rule language sufficiently addresses cyclic fatigue analysis. INGAA proposes to delete the reference to fracture mechanics modeling, which does not fit with this section of the rule.

PHMSA's proposal in subpart (e)(2) to require annual cyclic fatigue analysis is problematic because cyclic fatigue is not a typical threat to natural gas pipelines. Imposing this new requirement is overly burdensome for operators and not reasonably calculated to improve integrity management. PHMSA provides no technical basis for requiring annual cyclic fatigue analysis, which is consistent with its statement that this threat is not prevalent on gas pipelines.[228]

When prescribing any safety standard, PHMSA must consider relevant available gas pipeline safety information, the appropriateness of the standard for the type of transportation or facility, and the proposed standard's reasonableness.[229] Based on this lack of technical support and lack of incidents, PHMSA has failed to meet this burden. PHMSA has not demonstrated that the requirement to perform an annual cyclic fatigue analysis is warranted on natural gas pipelines

[226] Proposed § 192.917(e)(2).

[227] Proposed § 192.917(e)(2).

[228] During a webinar on June 28, 2016, PHMSA stated that, "Also, if you do have cracking issues with your pipeline, we do ask that you do a fracture mechanics modeling. Gas pipelines normally don't have cyclic fatigue issues, so on many or most of the lines, this problem will not be too much of a factor." http://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=117 (last accessed June 30, 2016).

[229] 49 U.S.C. § 60102(b)(2).

based on the evidence.[230] Natural gas pipelines generally have stable pressures and as a result are not susceptible to cyclic fatigue.[231] Cyclic fatigue is more typical of liquids pipelines, which tend to have greater pressure swings that lead to fatigue. Requiring cyclic fatigue analysis every year for facilities like natural gas pipelines that have stable pressure is unnecessary and wastes valuable resources that could be better directed elsewhere. It is unreasonable for PHMSA to impose a requirement for which there is no approved analytical method. PHMSA's proposal "runs counter to the evidence before the agency" and does not reflect a reasoned approach.[232]

INGAA agrees that cyclic fatigue analysis is appropriate as part of an overall integrity management plan, but proposes that it be required only once every seven calendar years. This timeline is consistent with the maximum reassessment interval for covered segments as required by the PSA.[233] This ensures that cyclic fatigue analysis is conducted periodically, consistent with the characteristics of natural gas pipelines. INGAA's proposal is appropriate because it strengthens the integrity management rules while prudently allocating resources.

4. Operators Should Be Permitted to Analyze Covered Segments for Manufacturing and Construction Defects According to ASME/ANSI B31.8S.

PHMSA's proposed language requiring an operator to analyze the covered segment to determine the risk of failure from manufacturing and construction defects is also problematic. The apparent requirement that an operator assess *all* seam-welded pipe for a manufacturing threat if the pipe does not meet the "stable defect" definition identified later in the rule is overly broad and has no technical basis.[234] Not all long seam weld types have a history of problems.

INGAA proposes to clarify the rule by adding language specifically stating that this analysis is required "according to the conditions specified in ASME/ANSI B31.8S." This would mimic language provided in subpart (e)(4), and provide clear direction to operators as to what pipelines need to be analyzed based on the PHMSA-accepted ASME/ANSI B31.8S standards. This clarification also would ensure that the requirement is in place only when an operator determines that a manufacturing or construction threat has been identified, not for all pipelines.

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[230] *Nat'l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 839, 843 (D.C. Cir. 1986) (vacating agency rule because record evidence did not support existence of the problem the rule purported to address).

[231] M.J. Rosenfeld, & J.F. Kiefner, Pipeline Research Council International Inc., Basics of Metal Fatigue in Natural Gas Pipeline Systems – A Primer for Gas Operations, Contract PR-302-03152 (June 30, 2006), Attachment 7; BMT Fleet Technology, Fatigue Considerations for Natural Gas Pipelines (June 30, 2016), Attachment 9.

[232] *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (vacating agency's rescission of regulation without adequate explanation); *Pub. Citizen v. FMCSA*, 374 F.3d 1209, 1216 (D.C. Cir. 2004) (finding that agency's failure to consider statutory factor constituted a failure to consider an important aspect of the problem).

[233] See 49 U.S.C. §60109(c)(3)(B); see also 192 C.F.R. §192.939

[234] Proposed § 192.917(e)(3).

This would achieve what the rule is intended to address by allowing operators to target pipe that is at risk due the manufacturing and construction defects.

5. Other Non-Substantive Changes

Finally, INGAA is proposing several changes to subsection (e) that remove potentially confusing redundancies or inaccuracies. This includes but is not limited to:

> (1) deletion of reference to §192.624(c) from subpart (e)(3), because it is inapplicable and already addressed by other requirements of the safety rules;
> (2) deletion of reference to “pipe body cracking” from subpart (e)(4), because this is already covered by subpart (e)(3);
> (3) deletion of the reference to §192.605(c) in subpart (e)(4), because it is not clear how it is applicable; and
> (4) deletion of reference to §192.624(c) and (d) in subpart (e)(4), because §192.624(c) is inapplicable (applies to MAOP, rather than fracture crack growth analysis) and §192.624(d) is already addressed in the rules for assessing seam integrity and seam corrosion anomalies.

INGAA’s proposal would provide additional clarity which will ensure that the new safety rules are clearly understood and can be effectively implemented by the operators.

C. Proposed Section 192.921

Existing Section 192.921 addresses the methods for conducting baseline assessments. The preamble to the NPRM states that the intent of the proposed changes to Section 192.921 is to require the use of in-line inspection and pressure testing over direct assessment (DA). NPRM at 20,817. The rule would also add three additional assessment methods, each of which the proposed rule considers preferable to DA, including spike hydrostatic pressure testing. INGAA is proposing changes the will ensure that operators have the flexibility to use the most appropriate assessment methodology for a given pipeline condition.

1. Direct Assessment - Proposed Section 192.921 (a)(6)

The NPRM’s proposed changes to § 192.921(a)(6) would limit the use of direct assessment to pipeline segments that cannot be assessed using in-line inspection tools and are “not practical” to assess using a subpart J pressure test, a “spike” hydrotest in accordance with § 192.506, excavation and *in situ* direct examination, or guided wave ultrasonic testing. The NPRM does not provide any data or technical justification for the proposed changes to §

192.921. It simply points to an NTSB Recommendation,[235] cites "ongoing research" without identifying or discussing said research,[236] and explains that, "At San Bruno, PG&E relied heavily on direct assessment under circumstances for which direct assessment was not effective.[…] Therefore, the proposed rule would require that direct assessment only be allowed when the pipeline cannot be assessed using in-line inspection tools." The NPRM neglects to address the fact that the San Bruno pipeline did not fail due to a corrosion anomaly, but rather due to an unstable manufacturing-related defect that had never been hydrostatically tested. DA is not an applicable assessment method for this type of defect. The San Bruno incident provides no justification for the NPRM's proposed changes to the requirements surrounding the use of direct assessment for corrosion threats.

The NPRM gives contradictory descriptions of the industry to the ANPRM, which overwhelmingly supported allowing operator flexibility in selecting effective assessment techniques.[237] Despite this, the NPRM states that industry response to the ANPRM "appear[s] to indicate that ILI and spike hydrostatic pressure testing is more effective than DA for identifying pipe conditions that are related to stress corrosion cracking defects." NPRM at p. 20,727.

INGAA is proposing 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, and not whether other assessment methods are possible.

DA is a thorough, four-step process. DA is a technically-based assessment method that provides a valuable assessment method for operators in the safe operation of natural gas pipelines. The industry standard for integrity management, ASME B31.8S-2004, which is

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[235] The proposed changes to this rule are designed to address one of the NTSB Recommendations from its 2015 Safety Study, "Integrity Management of Gas Transmission Pipelines in High Consequence Areas." Recommendation P-15-21 was for PHMSA to "[d]evelop and implement a plan for eliminating the use of direct assessment as the sole integrity assessment method for gas transmission pipelines."

[236] NPRM at p. 20,817

[237] *See* 68 Fed. Reg. 20722, at 20770-20771. ANPRM question G.2 asked "*Should the regulations require assessment using ILI whenever possible, since that method appears to provide the most information about pipeline conditions? Should restrictions on the use of assessment technologies other than ILI be strengthened? If so, in what respect? Should PHMSA prescribe or develop voluntary ILI tool types for conducting integrity assessments for specific threats such as corrosion metal loss, dents and other mechanical damage, longitudinal seam quality, SCC, or other attributes?"* Comments from various industry stakeholders, including trade organizations, pipeline operators, and standard-setting bodies, consistently supported the continued use of all assessment techniques without overly prescriptive limitations, in order to allow operators the flexibility to use engineering judgment to evaluate identified threats. Several commenters also noted that direct assessment is more appropriate for some threats, and that the operator is ultimately responsible for ensuring the threats on its pipelines are assessed. In fact, only one commenter, the California Public Utilities Commission, was noted by the NPRM suggesting that the use of DA should be limited.

incorporated by reference into the existing § 192.921, describes DA as "an integrity assessment method utilizing a structured process through which the operator is able to integrate knowledge of the physical characteristics and operating history of a pipeline system or segment with the results of inspection, examination, and evaluation, in order to determine the integrity."[238] Existing regulations §§ 192.923, 192.925, 192.927, and 192.929 govern the use of direct assessment and specify which threats it may be used to assess. Specifically, DA can only be used for external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA), and stress corrosion cracking (SCC) direct assessment (SCCDA) and are only appropriate for assessing the threats of those specific types of corrosion on a pipeline segment.

DA is used to identify locations where corrosion defects may have formed. The first of four steps requires the operator to evaluate and demonstrate the feasibility of DA to the location given the specific circumstances. The DA process integrates facilities data, current and historical field inspections and tests with the physical characteristics of a pipeline through a four-step process. Indirect examinations are used to monitor the adequacy of a pipeline's corrosion protection program, as well as coating integrity. The DA process also requires excavations, which confirm the ability of the indirect examinations to detect locations on the pipeline where active corrosion may be present and areas of significant coating damage at which corrosion could occur. The excavations also identify locations requiring remediation. A post-assessment step is required to determine the corrosion rate, set the re-inspection interval, reassess the performance of remediation measures and their continued applicability, and ensure the assumptions made in the previous steps remain correct, or where applicable, are adjusted.

INGAA proposes to clarify the way in which SCCDA can be used as an integrity assessment method. SCCDA is a valid way to assess for the SCC threat in gas pipelines for segments that are susceptible to SCC but have no history of SCC.[239] NACE has developed and periodically updated a standard practice for SCCDA, with the most recent version published in 2015.[240] SCCDA is a process that has been validated through round-robin testing. When there is a history of SCC, then an ILI or pressure spike test should be used.[241]

INGAA's proposal recognizes when to use particular assessment methods by allowing operators the flexibility to continue to utilize direct assessment when it can provide the necessary information about the pipe condition. For these reasons, PHMSA should adopt INGAA's proposed changes to Section 192.921(a)(6) of the NPRM, which are included below.

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[238] ASME/ANSI B31.8S at 19.

[239] ASME B31.8S (2012), Appendix A, Section 3.4.4 and Table A-3.4.1-1p. 51-52.

[240] NACE SP 0204 – 2015, Stress Corrosion Cracking (SCC) Direct Assessment Methodology.

[241] *Id*. at p. 51.

2. Spike Hydrostatic Testing

The NPRM's proposed changes to § 192.921 add subpart (a)(3), which addresses spike hydrostatic testing. Specifically, such subpart identifies "'Spike' hydrostatic pressure test in accordance with the NPRM's newly proposed § 192.506. INGAA agrees that the use of spike hydrostatic testing is appropriate for time-dependent threats such as stress corrosion cracking. INGAA proposes changes to the NPRM's new § 192.506, and the cross-reference in new § 192.921(a)(3), to limit the spike testing requirement to time-dependent threats, to test to a minimum of 100% SMYS instead of 105%, and to provide an alternative for use of an instrumented leak survey.

In the NPRM, PHMSA proposes in § 192.506 that "each segment of an existing steel pipeline that is operated at a hoop stress level of 30 % of specified minimum yield strength or more and has been found to have integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment must be strength tested by a spike hydrostatic pressure test." [242] The NPRM provides little discussion of the inclusion of spike hydrostatic testing in § 192.921, other than to say that it "is particularly well suited to address SCC and other cracking or crack-like defects." NPRM at p. 20,817.

The spike test is a variant of the hydrostatic test in which the pressure is initially raised to a prescribed level above the minimum test pressure for a short period and then reduced for the remaining duration of the test. INGAA agrees 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 in service. INGAA also notes that a spike test may be of value for in-service pipelines where metallurgical fatigue is of concern. An example would be on a line that undergoes significant pressure cycling. Gas pipelines typically do not undergo significant pressure cycling and their fatigue lives can be hundreds of years in duration. Pressure cycling does not need to be included in § 192.506. PHMSA should amend §§ 192.506 and 192.921(a)(3) to limit spike testing only to those segments with stress corrosion cracking.

INGAA also recommends some clarifications and additions to the spike testing methodology in § 192.506. PHMSA proposes that an operator use the lesser of 1.5 times MAOP or 105% of SMYS for spike tests. INGAA recommends that spike tests be required to reach a minimum of 100% of SMYS along a segment of pipe instead of 105% and that the reference to 1.5 times MAOP be deleted. These recommendations are based on work conducted in the U.S. and Canada.[243] As shown in Figure 1 in Section I. MAOP Reconfirmation, there is little

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[242] 49 C.F.R. § 192.506.

[243] Canadian Energy Pipeline Association, Stress Corrosion Cracking, Recommended Practice, p.9-20; Fessler, Raymond, David Batte and Mark Hereth, Joint Industry Project on Integrity Management of Stress Corrosion

incremental safety benefit to use 105% of SMYS instead of 100% of SMYS as the minimum spike pressure. In Figure 1, the increase in the factor of safety is just 1%. Attempting to achieve that tiny increase in the safety margin has substantial impacts on the planning and execution of hydrostatic testing.

In pipeline sections with elevation change, some pipe (especially pipe at lower elevations) will experience a higher stress level to achieve a minimum of 100% at the highest location of the test section. To prevent bulging of the pipe, there is a practical limitation of approximately 110% of SMYS as the maximum test pressure for any location on the pipe.[244] In conducting a hydrostatic test, changes in elevation must be taken into account. The minimum pressure will occur at the highest location in the test section, and correspondingly, the highest pressure will occur at the lowest point. The small differential between 105% and 110% SMYS means that the test sections will necessarily be shorter and there will need to be more test sections. Having to test more sections will result in outages of longer duration, increased methane emissions, increased consumption of water for testing, and increased cost to conduct the testing. A level of 100% of SMYS is more appropriate.

Spike test levels have been specified in international consensus standards such as API RP 1110 and ASME B31.8S (Managing System Integrity of Gas Pipelines), since the mid-2000s. ASME B31.8S-2007 is incorporated by reference into the PHMSA regulations in 49 C.F.R. § 192.7. In its 2010 edition, ASME added spike testing to address environmentally assisted cracking, typically manifested as stress corrosion cracking in pipelines. Work conducted in a Joint Industry Project (JIP) on Managing Stress Corrosion Cracking in High Consequence Areas,[245] served as the technical foundation for incorporation of spike testing for SCC into ASME B31.8S. JIP experts studied incidents and pressure testing histories for pipelines dating back to the 1980s. The JIP concluded that spike tests to at least 100% of SMYS were recommended to identify critical stress corrosion cracking.[246]

PHMSA proposes in § 192.506 that spike tests must be held for at least 30 minutes within the first two hours of the eight-hour hydrostatic pressure test.[247] After completing the spike portion of the test, a leak test can be conducted by continuing the hydrostatic test at a lower pressure. The hold time should be long enough to allow the pressure to stabilize, demonstrating that there are no leaks. This provides sufficient time for the water temperature to equilibrate with

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Cracking in Gas Pipeline High Consequence Areas, ASME STP-PT-011, 2008.

[244] *Id*. at pp.8, 81; Fessler.; INGAA Foundation, the Effect of Pipe Expansions on Fusion Bonded Epoxy Coatings, Energy Pipeline Industry Pipe Quality Action Plan, November 5, 2010.

[245] *Id*.

[246] *Id*., Tables 29 and 30, p.77.

[247] 49 C.F.R. § 192.506(e).

the ground temperature and for residual gases to be absorbed by the water. Typically, eight hours has been sufficient for those purposes. INGAA supports the inclusion of the 8 hours in the proposed rule.

As an alternative to holding the pressure test after the spike increment, an instrumented survey using a flame ionization detector or equivalent technology can be conducted as a check for leaks after the pipeline is re-pressurized. A number of gas pipeline companies have found that a flame ionization survey after the pipe is re-pressurized with gas is a more sensitive test for leaks than a long hold time with water in the pipe. Natural gas tends to rise from a leak and can be readily detected. Water leaking from a pipe during a hydrostatic test may not come to the surface but the flame ionization detector would still detect the leak. Flame ionization should be an acceptable alternative to a leak test with water pressure. For these reasons, INGAA proposes that after the spike increment, the operator be permitted to use a leak survey in lieu of holding the pressure test after the spike portion is completed. This alternative provides the same margin of safety without the same potential negative impacts. Last, INGAA recommends that PHMSA remove the burdensome pre-notification and "no objection" letter requirements from § 192.506 for the same reasons discussed in the MAOP reconfirmation section. Proposed rule text for both §§ 192.506 and 192.921(a)(3) is included below.

3. Other Aspects of § 192.921 – Subpart (a)(1)

Existing Section 192.915(b) already requires that a qualified person analyze ILI data. Therefore, the qualification requirement in § 192.921(a)(1) is redundant and unnecessary. As with INGAA's other suggestions in Subpart O discussed above with respect to § 192.917(e), INGAA is proposing clarifying changes in the proposed rule text below that remove redundancies from the rule to ensure clarity. This will improve the safety and compliance of operators.

4. PHMSA's PRIA Fails to Demonstrate that the Costs of § 192.921 Are Commensurate with its Safety Benefits.

PHMSA has not demonstrated that the costs of ILI and hydrostatic testing are justified when the identified threats on the pipeline can be effectively assessed using DA. Requiring the use of a spike hydrotest or a crack detection ILI tool where the general threat of SCC applies but there is no history or evidence of SCC will impose a significant cost on operators that will not have commensurate safety benefits.

The PRIA mischaracterizes the changes that are proposed to Section 192.921, stating that the proposed rule would require that DA only be allowed when the pipeline cannot be assessed using ILI.[248] By contrast, a reading of the proposed rule itself reveals that operators would only be allowed to use DA when ILI is not possible and hydrostatic pressure testing, spike testing, GWUT, and excavation are not practical. Based on its mischaracterization of the rule, the PRIA concludes that this aspect of the proposed rule "would not impose a significant additional cost burden on pipeline operators." This conclusory statement is not supported, and does not consider the additional cost burden of requiring other costly assessment methods to be used when practical.

With respect to the additional assessment methods of spike pressure testing, GWUT, and excavation with *in situ* examination, the PRIA states: "All of these assessment methods are implicitly allowed by existing requirements; the proposed rule would not mandate use."[249] However, on lines that previously were allowed to be assessed for corrosion threats using DA, the proposed rule *does* mandate that they be used when practical, and the PRIA fails to include this additional cost burden.

Finally, the PRIA does not consider the costs of the effects of spike hydrostatic testing. Spike hydrostatic testing can cause damage to pipeline coating and can cause failures on pipe that would survive normal operating conditions or a Subpart J test. Not only has PHMSA failed to consider the cost to operators of conducting these tests, but also has failed to consider the costs of repairs to coating and pipe replacement for these segments that fail an unnecessary and overly burdensome spike test. For these reasons, PHMSA's PRIA fails to properly assess the significant cost on operators that will result from the proposed changes to Section 192.921, which are not commensurate safety benefits.

D. INGAA's Proposed Regulatory Text.

§ 192.506 Transmission lines: Spike hydrostatic pressure test for existing steel pipe with integrity threats.

(a) Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and has been found to have time-dependent cracking, including stress corrosion cracking ~~integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment~~ must be strength tested by a spike hydrostatic pressure test in accordance with this section to substantiate the proposed maximum allowable operating pressure.

(b) The spike hydrostatic pressure test must use water as the test medium.

[248] PRIA at p. 71 ("DA is typically not chosen as the assessment method if the pipeline can be assessed using ILI.")
[249] *Id.* at 72.

(c) The baseline test pressure without the additional spike test pressure is the test pressure specified in §§ 192.619(a)(2), 192.620(a)(2), or 192.624, whichever applies.

(d) The test must be conducted by maintaining the pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505(e).

(e) After the test pressure stabilizes at the baseline pressure and within the first two hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of ~~the lesser of 1.50 times MAOP or~~ ~~105%~~ 100% SMYS. This spike hydrostatic pressure test must be held for at least 30 minutes. After the 30-minute spike interval, the operator may either hold the baseline pressure for the remainder of the 8 hour test interval or, alternatively, an operator can conclude the hydrostatic pressure test after the spike interval and conduct an instrumented leak survey after the pipeline is placed back into service.

(f) ~~If the integrity threat being addressed by the spike test is of a time-dependent nature such as a cracking threat, t~~The operator must establish an appropriate retest interval and conduct periodic retests at that interval using the same spike test pressure. The appropriate retest interval and periodic tests for the time-dependent threat must be determined in accordance with the methodology in § 192.624(d).

(g) *Alternative technology or alternative technical evaluation process.* Operators may use alternative technology or an alternative technical evaluation process that provides a sound engineering basis for establishing a spike hydrostatic pressure test or equivalent. ~~If an operator elects to use alternative technology or an alternative technical evaluation process, the operator must notify PHMSA at least 180 days in advance of use in accordance with § 192.624(e). The operator must submit the alternative technical evaluation to the Associate Administrator of Pipeline Safety with the notification and must obtain a "no objection letter" from the Associate Administrator of Pipeline Safety prior to usage of alternative technology or an alternative technical evaluation process. The notification must include the following details:~~

~~(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;~~

~~(2) Procedures and processes to conduct tests, examinations, and assessments, perform evaluations, analyze defects and flaws, and remediate defects discovered;~~

~~(3) Data requirements including original design, maintenance and operating history, anomaly or flaw characterization;~~

~~(4) Assessment techniques and acceptance criteria;~~

~~(5) Remediation methods for assessment findings;~~

~~(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;~~

~~(7) Procedures for remaining crack growth analysis and pipe segment life analysis for the time interval for additional assessments, as required; and~~

~~(8) Evidence of a review of all procedures and assessments by a subject matter expert(s) in both metallurgy and fracture mechanics.~~

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

[…]

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather, ~~verify,~~ validate, and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in paragraph (b)(1) of this section. ~~and Appendix A to ASME/ANSI B31.8S.~~ ~~and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.~~ Where data is missing, conservative assumptions shall be used when performing the risk assessment. An operator may collect any newly identified data consistent with the timelines set forth in § 192.624(b). The evaluation must analyze ~~both~~ the covered segment and consider similar non-covered segments as follows: ~~, and must:~~

(1) Integrate information about pipeline attributes and other relevant information, including, but not limited to.

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

(ii)Manufacturer and manufacturing date, including manufacturing data and records;

~~(iii) Material properties including, but not limited to, diameter, wall thickness, grade, seam type, hardness, toughness, hard spots, and chemical composition;~~

~~(iv) Equipment properties;~~

(~~v~~iii) Year of installation;

(~~vi~~iv) Bending method;

(~~vii~~v) Joining method~~, including process and inspection results~~;

(~~viii~~vi) Depth of cover surveys including ~~stream and~~ river crossings and navigable waterways~~, and beach approaches~~;

(~~ix~~vii) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;

(~~x~~viii) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;

(~~xi~~ix) Pipe coating methods (both manufactured and field applied) including method or process used to apply girth weld coating, inspection reports, and coating repairs;

(~~xii~~x) Soil~~, backfill~~;

(~~xiii~~xi) Construction inspection reports, including but not limited to:

~~(A) Girth weld non-destructive examinations;~~

~~(B)~~ Post backfill coating surveys;

~~(C) Coating inspection ("jeeping") reports;~~

(~~xiv~~xii) Cathodic protection installed, including but not limited to type and location;

~~(xv) Coating type;~~

(~~xvi~~xiii) Gas quality;

(~~xvii~~xiv) Flow rate;

(~~xviii~~xv) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);

(~~xix~~xvi) Class location;

(~~xx~~xvii) Leak and failure history including any in-service ruptures or leaks from incident reports, abnormal operations, safety related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences;

(~~xxi~~xviii) Coating condition;

~~(xxii) CP system performance;~~

(~~xxiii~~xix) Pipe wall temperature;

(~~xxiv~~xx) Pipe operational and maintenance inspection reports, including but not limited to:

(A) Data gathered through integrity assessments required under this part, including but not limited to in-line inspections, pressure tests, direct assessment, guided wave ultrasonic testing, or other methods;

(B) Close interval survey (CIS) and electrical survey results;

(C) Cathodic protection (CP) rectifier readings;

(D) CP test point survey readings and locations;

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

(F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including but not limited to direct current voltage gradient or alternating current voltage gradient inspections;

(G) Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe coating condition, see § 192.459), including the results of any non-destructive examinations of the pipe, seam or girth weld, i.e. bell hole inspections;

(H) Stress corrosion cracking (SCC) excavations and findings;

(I) Selective seam weld corrosion (SSWC) excavations and findings;

(J) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;

(~~xxv~~xxi) Outer Diameter/Inner Diameter corrosion monitoring;

(~~xxvi~~xxii) Operating pressure history and pressure fluctuations, including analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;

(~~xxvii~~xxiii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;

(~~xxviii~~xxiv) ~~Encroachments and right-of-way activity, including but not limited to, one-call data, pipe exposures resulting from encroachments, and excavation activities due to development or planned development along the pipeline~~ One call data - Encroachments to the pipeline and ROW;

(~~xxix~~xxv) Repairs;

(~~xxx~~xxvi) Vandalism;

(~~xxxi~~xxvii) External forces;

(~~xxxii~~xxviii) Audits and reviews;

(~~xxxiii~~xxix) Industry experience for incident, leak and failure history;

(~~xxxiv~~xxx) Aerial photography;

(~~xxxv~~xxxi) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area; and

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

(2) Use objective~~, traceable, verified,~~ and validated information and data as inputs, where the operator is missing data, conservative assumptions shall be used when performing risk assessment as noted in B31.8S Appendix A. ~~to the maximum extent practicable.~~ If input is obtained from subject matter experts (SMEs), the operator must employ adequate control measures to ensure consistency and accuracy of information~~. measures to adequately correct any bias in SME input. Bias control measures may include training of SMEs and use of outside technical experts (independent expert reviews) to assess quality of processes and the judgment of SMEs. Operator must document the names of all SMEs and information submitted by the SMEs for the life of the pipeline.~~

~~(3) Identify and analyze spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings; evidence of pipeline damage where overhead imaging shows evidence of encroachment). Storing or recording the information in a common location, including a geographic information system (GIS), alone, is not sufficient;~~ and

(4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

(c) *Risk assessment.* An operator must conduct a risk assessment that analyzes ~~follows ASME/ANSI B31.8S, section 5, and considers~~ the identified threats and potential consequences of an incident for each covered segment. ~~The risk assessment must include evaluation of the effects of interacting threats, including the potential for interactions of threats and anomalous conditions not previously evaluated~~ An operator must ensure validity of the methods used to conduct the risk assessment in light of incident, leak, and failure history and other historical information. Validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the probability of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to ~~prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.~~ determine additional preventive and mitigative measures needed (§ 192.935) for each covered segment, and periodically evaluate the integrity of each covered pipeline segment (§ 192.937(b)). The risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas~~, including the consequences of the entire worst-case incident scenario from initial failure to incident termination;~~

(2) Analyze the likelihood of failure due to each individual threat or risk factor, and each unique combination of threats or risk factors that interact or simultaneously contribute to risk at a common location;

(3) Lead to better understanding of the nature of the threat, the failure mechanisms, the effectiveness of currently deployed risk mitigation activities, and how to prevent, mitigate, or reduce those risks;

(4) Account for, and compensate for, uncertainties in ~~the model and~~ the data used in the risk assessment; and

(5) Evaluate the potential risk reduction associated with candidate risk reduction activities ~~such as preventive and mitigative measures and reduced anomaly remediation and assessment intervals~~.

[…]

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

[…]

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading conditions (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. ~~An~~The evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment. ~~Fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis must be conducted in accordance with § 192.624(d) for cracks.~~ Cyclic fatigue analysis must be ~~annually, not to exceed 15 months~~ conducted periodically, not to exceed seven (7) calendar years.

(3) *Manufacturing and construction defects.* ~~If an operator identifies the threat of~~ An operator must analyze the covered segment to determine the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment according to the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A5.3. ~~an operator must analyze the covered segment to determine the risk of failure from these defects.~~ The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to a hydrostatic pressure testing satisfying the criteria of subpart J of this part of at least 1.25 times MAOP, and the segment has not experienced an in-service incident attributed to a manufacturing or construction defect since the date of the pressure test. ~~operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area.~~ If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment~~, and must reconfirm or reestablish MAOP in accordance with §192.624(c)~~.

(i) ~~Operating pressure increases above the maximum operating pressure experienced during the preceding five years;~~ The segment has experienced an in-service incident as described in §192.624(a)(1).

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe, pipe with seam factor less than 1.0 as defined in §192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including but not limited to ~~pipe body cracking,~~ seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years ~~(including abnormal operation as defined in §192.605(c))~~, or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment. ~~Pipe with cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 192.624(c) and (d).~~

§ 192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of line pipe in each covered segment by applying one or more of the following methods ~~depending on the~~ for each threat~~s~~ to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* § 192.917). In addition, an operator may use an integrity assessment to meet the requirements of this section if the pipeline segment assessment is conducted in accordance with the integrity assessment requirements of § 192.624(c) for establishing MAOP.

(1) Internal inspection tool or tools capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. ~~An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment~~. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. ~~A person qualified by knowledge, training, and experience~~ An operator must analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

[…]

(3) "Spike" hydrostatic pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for threats such as stress corrosion cracking~~,~~ ~~selective seam weld corrosion, manufacturing and related defects, including defective pipe and pipe seams, and other forms of defect or damage involving cracks or crack-like defects~~;

[…]

(6~~3~~) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. Use of external corrosion direct assessment and internal corrosion direct assessment is allowed only if the line is not capable inspection by internal inspection tools and is not practical to assess using the methods specified in paragraphs (d)(1) through (d)(5) of this section. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with~~, as~~ the applicable, the requirements specified in §§ 192.925, 192.927 or 192.929; or

XIII. Cumulative Impact of the NPRM

PHMSA has not recognized the cumulative impact of its individual proposals in the NPRM. Each regulatory section cannot be viewed in isolation. Language within many individual sections that purports to limit their application to specific pipeline segments is undermined by cross references that effectively impose some of the NPRM's most burdensome provisions on almost all transmission pipelines. The material verification provision in § 192.607 is supposedly limited to pipelines located in HCAs and class 3 or 4 locations that do not have reliable, traceable, verifiable, and complete records.[250] Yet, in § 192.13(e)(3), PHMSA proposes that when "records are not available, *each operator* must reestablish pipeline material documentation in accordance with the requirements of § 192.607."[251] It could be perceived that § 192.13(e)(3) expands the reach of § 192.607 to all pipelines regulated under part 192 because § 192.13(e) is part of the general requirements that apply to all pipelines regulated under Part 192. Subsection (e), in particular, covers all pipelines ("*Each* operator must make and retain records that demonstrate compliance with this part."). Due to the cross-reference in § 192.13(e)(3), PHMSA is proposing in one section of the code that all operators regulated under Part 192 comply with § 192.607 while limiting the scope of § 192.607 elsewhere to only those pipelines that are located in HCAs and class 3 or 4 locations that do not have RTVC records.

Several other provisions reference § 192.607, expanding the application of this section far more broadly than the text of § 192.607 would initially suggest. In proposed § 192.485(c), PHMSA states that if a pipeline operator does not have RTVC records for material properties supporting the remaining strength calculations, then the operator must base the calculation on properties "determined and documented in accordance with § 192.607." Since § 192.485 applies to all transmission lines,[252] PHMSA has expanded the reach § 192.607 beyond those pipelines in HCAs and Class 3 or 4 locations. PHMSA takes the same approach in section § 192.713(d)(1)(i) and in multiple places in § 192.713(d) which also apply to all transmission lines to establish the requirements for permanent field repairs. INGAA recommends that PHMSA remove the multiple references to § 192.607 in §§ 192.485 and 192.713(d).

In addition, by requiring operators to analyze certain information under the material verification requirements first, PHMSA is accelerating the deadlines associated with § 192.607.

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[250] INGAA references "reliable" in an effort to correctly summarize PHMSA's proposal. However, INGAA does not support the use of "reliable" to describe acceptable records.

[251] Proposed § 192.13(e) (emphasis added).

[252] Section 192.485 is entitled "Remedial measures: Transmission lines" and currently effective § 192.485(a) (not altered by the NPRM) applies to "each segment of transmission line." There is no distinction of the location of the transmission line.

INGAA questions how an operator can proceed with the material verification work on an opportunistic basis, as PHMSA has proposed, and yet gather the required information in time to meet the deadlines for other code sections. In § 192.624(c)(3), PHMSA proposes that an operator may reconfirm its MAOP through an engineering critical assessment (ECA). The ECA must analyze any cracks or crack-like defects remaining in the pipe. INGAA has raised several substantive concerns with the ECA method in § 192.624(c). There is also a timing question that is raised by PHMSA's proposal. If actual material toughness is not known, the NPRM directs operators to determine the Charpy v-notch toughness based on material documentation created through the § 192.607 verification work.[253] To comply, an operator would have to complete the § 192.607 work <u>first</u>, and then reconfirm MAOP through one of the acceptable methods including ECA. Given the deadlines to complete MAOP reconfirmation in § 192.624, it is questionable whether an operator could really complete the verification work on an opportunistic basis, without additional cost, as PHMSA has assumed in the PRIA.[254]

Neither the NPRM, the PRIA nor the Draft EA acknowledge the actual reach and costs of the proposed regulations. The cumulative impact of these cross-references would require operators that are missing RTVC records to conduct the material verification work for *all* pipelines and complete the necessary excavations sooner rather than later to meet the deadlines for MAOP reconfirmation. PHMSA should either delete these cross-references or reevaluate its cost-benefit assessment of its proposal to ensure it is consistent with the agency's proposal.

[253] Proposed § 192.624(c)(3)(i)(B).
[254] PRIA at 122, § 4.1.2.3.

XIV. Other Aspects of the NPRM

A. PHMSA's Proposal to Require Inspections of Pipelines After Extreme Weather Events Is Duplicative.

PHMSA proposes to require that pipeline operators perform inspections of "all potentially affected onshore transmission pipeline facilities" after extreme weather events, e.g., hurricanes, floods, earthquakes, landslides, or natural disasters.[255] A pipeline operator would be required to perform these inspections within 72 hours of the "cessation of the event" (as measured from the time when the affected area is safely accessible to personnel and equipment).[256]

While INGAA recognizes the importance of inspecting pipelines after extreme weather events, operators are already required to have procedures to ensure a prompt and effective response to emergency conditions under § 192.615.[257] Section 192.615 requires pipeline operators to identify the type of events, including natural disasters, that necessitate an immediate response, require an emergency shutdown and pressure reduction (if necessary), determine the availability of personnel and equipment needed at the scene, and notify local responders of the emergency.[258] Operators must also coordinate planned responses with fire, police, and other public officials.[259] Finally, an operator must include these procedures in its operation and maintenance manual.[260]

In order to address PHMSA's concerns and avoid duplicative regulation, PHMSA should modify § 192.615(a)(3) to incorporate additional specificity on weather events that may trigger a prompt and effective response.

1. PHMSA Should Replace the 72-Hour Requirement With "As Soon As Practicable" or Create a Process to Request an Exception if It Is Unsafe or Impracticable to Access the Pipeline.

In the NPRM, PHMSA proposes that an operator begin the § 192.613(c) inspection within 72 hours of the "cessation of the event, defined as the point in time when the affected area can be safely accessed by the personnel and equipment, including availability of personnel and equipment, required to perform the inspection as determined under paragraph (c)(1) of this

[255] Proposed 49 C.F.R. § 192.613(c).
[256] *Id.*
[257] 49 C.F.R. § 192.615(a)(3).
[258] 49 C.F.R. § 192.615(a)(1)-(11).
[259] *Id.*
[260] 49 C.F.R. § 192.605(e).

section, whichever is sooner."[261] Instead of a strict 72-hour requirement, INGAA recommends that PHMSA amend its proposal to require the inspection to begin "as soon as practicable after the cessation of the event." The 72-hour time frame will not always suffice since operators will need to determine when it is reasonable to conduct the inspection taking into account not only personnel safety but also the availability of vendors. Alternatively, if PHMSA elects to keep the 72-hour requirement, the agency should permit operators to seek an exception through notice to the agency.

2. PHMSA Should Clarify Its Proposed Regulatory Text.

In § 192.613(c)(2), PHMSA proposes that the inspection must begin within 72 hours after the "cessation of the event" defined as "the point in time when the affected area can be safely accessed by the personnel and equipment, including availability of personnel and equipment, required to perform the inspection as determined under paragraph (c)(1) of this section, whichever is sooner."[262] INGAA recommends that PHMSA delete the "whichever is sooner" language to eliminate any confusion.

PHMSA should also replace "including" with "taking into account." Finally, PHMSA should characterize "other similar event" as those that have the likelihood of *significant* damage to *pipeline facilities*. Without the qualifier of "significant", PHMSA leaves open the question of whether a heavy snow storm or derecho rain event might trigger these requirements. INGAA includes "pipeline facilities" instead of "infrastructure" since PHMSA does not have jurisdiction over non-pipeline infrastructure.

3. PHMSA Should Modify the Proposed Regulatory Text as Follows:\

§ 192.613 Continuing surveillance.

[…]

(c) Following an extreme weather event such as a hurricane or flood, an earthquake, landslide, a natural disaster, or other similar event that the operator determines to have the likelihood of significant damage to pipeline facilities ~~infrastructure~~, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

[…]

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[261] Proposed 49 C.F.R. § 192.613(c)(2).
[262] *Id.*

(2) Time period. The inspection required under the introductory text of paragraph (c) of this section must commence as soon as practicable ~~within 72 hours~~ after the cessation of the event, defined as the point in time when the affected area can be safely accessed by the personnel and equipment, ~~including~~ taking into account the availability of personnel and equipment required to perform the inspection as determined under paragraph (c)(1) of this section~~, whichever is sooner~~.

B. PHMSA Must Modify Its Management of Change Proposal to Better Align with ASME/ANSI B31.8S and to Allow Time for Implementation.

PHMSA proposes to revise the general requirements in § 192.13 to require each gas transmission pipeline operator to develop and follow a management of change (MOC) process as outlined in ASME/ANSI B31.8S, section 11. PHMSA proposes that the MOC process address technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline, whether permanent or temporary. [263] This list of requirements goes beyond the requirements in ASME/ANSI B31.8S, section 11, and fails to recognize the need for MOC to be flexible to fit the situation. PHMSA should eliminate the changes it proposed to § 192.13 that go beyond the recommendations of ASME/ANSI B31.8S. PHMSA must account for the time and effort to develop and implement an electronic MOC system. INGAA proposes to establish a deadline of five years from the effective date of the final rule instead of requiring immediate compliance. Under the PRA, PHMSA must also re-evaluate the burden and cost of § 192.13 rather than erroneously assuming that there is no cost associated with implementing MOC.[264]

Instead of using ASME/ANSI B31.8S, as written, PHMSA proposes to add design, environmental, operational, and maintenance considerations to the MOC process without any technical support. PHMSA also fails to include key language from ASME/ANSI B31.8S that MOC "procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them."[265] As written, the PHMSA language could be read to require an MOC for every minor change or operation. PHMSA's proposal could be read to require an operator to perform an MOC when it changes a cathodic protection rectifier or inspects or maintains a valve. If PHMSA intends to require an MOC on each and every individual task or change, then the number of MOCs will exponentially increase.

[263] Proposed § 192.13(d).

[264] PRIA at 70, § 3.2.2 ("Since these are not new requirements, PHMSA concluded that this requirement would not impose an additional cost burden on pipeline operators.")

[265] ASME B31.8S-2004, Managing System Integrity of Gas Pipelines at 32, Section 11.

PHMSA failed to include its changes to § 192.13(d) in its request to revise its existing information collection approvals. In the NPRM, PHMSA proposes to amend its information collection for general recordkeeping requirements for natural gas operators. However, PHMSA only revises the collection to incorporate the addition of gas gathering pipeline operators. PHMSA neglected to revise its burden assessment to reflect management of change and erroneously assumes that the burden on transmission operators is zero.[266] Contrary to PHMSA's assertion, this proposal creates significant burdens for operators of transmission pipelines. First, PHMSA is proposing to apply MOC provisions for *all* operators, not just operators with pipelines in HCAs as required by the existing Subpart O requirements. HCAs cover approximately 6% of transmission pipelines, so PHMSA's proposal effectively expands the MOC requirement from 6% to 100% of transmission pipelines. Second, PHMSA is proposing that operators not only comply with ASME/ANSI B31.8S, section 11, similar to the requirements in Subpart O, but PHMSA is also including additional considerations of design, environmental, operational, and maintenance. Adding these elements will increase the time and costs to comply.

As proposed, PHMSA would expect operators to comply with the MOC provisions upon the effective date of the final rule. Requiring immediate compliance with the proposal is unrealistic and burdensome. Immediate implementation ignores the fact that while many pipeline operators have MOC programs already, approximately 50% of INGAA members have non-electronic, paper MOC systems. Implementation of proposed § 192.13(d) will require an electronic MOC system. Migration from a paper system to an electronic system and expansion of MOCs to all facilities outside of HCAs requires time to build or acquire an electronic MOC system, populate the system, and train employees to use it. In recognition of these necessary steps, INGAA requests that PHMSA set the deadline for compliance to be five (5) years after the effective date of the final rule. This deadline is also consistent with API RP 1173[267] which includes MOCs as one element of a pipeline Safety Management System (SMS). PHMSA has already recognized that operators need time to voluntary implement SMS, including MOC.

PHMSA underestimates the time and cost of implementation of an MOC as well as the number of MOCs that will be required and the cost to perform each of these MOCs. In its Cost Analysis (Attachment 6), INGAA estimates that the burden for interstate and intrastate pipeline operators to comply with the changes in § 192.13(d) is as follows:

[266] PRIA at 70, § 3.2.2.

[267] API, RP 1173, Pipeline Safety Management Systems, (July 2015).

Element	Industry Cost	PHMSA Cost
Average One-Time Cost of Revising MOC	$34,805,163	$426,281
Annual Cost of Implementing MOC	$296,751,472	$977,760
Total Cost	$354,566,063	$1,404,041
3% Discount (10-Yr)	$2,607,290,756	$12, 448,803
7% Discount (10-Yr)	$2,230,156,232	$9,954,924
3% Annual Cost	$295,534,239	$829,920
7% Annual Cost	$257,820,786	$663,662

Source: RIA and Operator Data

PHMSA should remedy the deficiencies summarized above by adopting the following rule text for § 192.13(d).

1. INGAA's Proposed Regulatory Text Related to Management of Change

§ 192.13 What general requirements apply to pipelines regulated under this part?

[…]

(d) Within [five (5) years from effective date of the Final Rule] ~~E~~each operator of an onshore gas transmission pipeline must ~~evaluate and mitigate, as necessary, risks to the public and environment as an integral part of managing pipeline design, construction, operation, maintenance, and integrity, including management of change. Each operator of an onshore gas transmission pipeline~~ develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical design, physical, ~~environmental~~, procedural, ~~operational, maintenance~~, and organizational changes to the pipeline or processes, whether permanent or temporary. Depending on the nature of the change, ~~A~~a management of change process must include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. These procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them.

C. PHMSA Should Modify Its Proposed Definitions of "Close-Interval Survey," "Dry Gas," and "Electrical Survey."

For the first time, PHMSA proposes to define "close-interval survey," "dry gas," and "electrical survey" in its regulations at § 192.3. INGAA recommends that PHMSA use the existing consensus standard definitions for these terms. These definitions already are used and relied upon by industry.

INGAA proposes that PHMSA replace its definition of “close-interval survey” (CIS) with the NACE definition.[268] NACE defines close-interval survey as “a potential survey performed on a buried or submerged metallic pipeline, in order to obtain valid DC structure-to-electrolyte potential measurements at a regular interval sufficiently small to permit a detailed assessment.”[269] PHMSA defines the same term as “a series of closely spaced pipe-to-electrolyte potential measurements taken to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary.”[270] This definition is not clear and may cause confusion as to which threats a CIS can identify. The purpose of a CIS is not to quantify IR drops, as PHMSA suggests. In fact, in offshore and marsh areas where there are galvanic bracelet anodes, in areas of alternating current mitigation, uninterruptible cathodic protection current, or depolarized surveys, a CIS would not quantify IR drop. A CIS is not an effective method for identifying locations where alternating stray current is interfering with the pipeline and causing corrosion.

INGAA recommends that PHMSA replace its definition of “dry gas” with the NACE SP0206.[271] NACE defines this term as “a gas above its dew point and without condensed liquids.”[272] In comparison, PHMSA proposes to define this term as “gas with less than 7 pounds of water per million (MM) cubic feet and not subject to excessive upsets allowing electrolytes into the gas stream.”[273] This definition is not technically correct. Gas at water vapor levels higher than 7 pounds can be dry (have no liquid water) depending on temperature and pressure inside the pipeline, and under certain operating conditions seven pounds of water vapor gas can be wet. Use of PHMSA’s definition could lead to conditions with condensed water at lower temperatures. PHMSA should use the NACE definition or modify the NACE definition to address water dew point only.

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[268] NACE SP0207-2007, Performing Close-Interval Potential Survey and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines at 3 (as referenced by NACE SP0502-2010, Pipeline External Corrosion Direct Assessment Methodology).

[269] NACE SP0207-2007, Performing Close-Interval Potential Survey and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines at 1, 3.

[270] Proposed 49 C.F.R. § 192.3.

[271] NACE SP0206-2006, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas.

[272] NACE SP0206-2006, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas at 5.

[273] Proposed 49 C.F.R. § 192.3.

INGAA recommends that PHMSA replace its definition of "electrical survey" with the definition from NACE SP0207.[274] PHMSA defines the term as "a series of closely spaced measurements of the potential difference between two reference electrodes to determine pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline on ineffectively coated or bare pipelines."[275] This definition describes a cell-to-cell "hot-spot survey." NACE defines "hot-spot survey" as "a cell-to-cell surface potential gradient survey consisting of a series of potential gradients measured along the pipeline, often used on pipelines that are not electrically continuous or on bare or ineffectively coated pipelines in order to detect the probable current discharge (anodic) areas along a pipeline. Where the pipeline is electrically continuous, a close-interval survey and lateral potentials will also detect areas of probable current discharge (anodic areas)."[276] PHMSA's proposed definition is neither clear nor technically correct. This definition is not sufficient to define an electrical survey. There are other examples of surveys that would fit this definition and not be applicable to unprotected pipelines. Alternatively, if PHMSA intends a broader interpretation of electrical survey, the definition of "indirect inspection" in NACE SP0502 is defined as "equipment and practices used to take measurements at ground surface above or near a pipeline to locate or characterize corrosion activity, coating holidays, or other anomalies."[277]

Since PHMSA's proposed definitions of "close-interval survey," "dry gas," and "electrical survey" will cause confusion, PHMSA should adopt the definitions created by NACE and used by industry.

INGAA's Proposed Regulatory Text Relating to Definitions

§ 192.3 Definitions.

Close interval survey means a ~~series of closely spaced pipe-to-electrolyte potential measurements taken to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary.~~ potential survey performed on a buried or submerged metallic pipeline, in order to obtain valid DC structure-to-electrolyte potential measurements at a regular interval sufficiently small to permit a detailed assessment.

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[274] NACE SP0207-2007, Performing Close-Interval Potential Survey and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines at 4.

[275] Proposed 49 C.F.R. § 192.3.

[276] NACE SP0207-2007, Performing Close-Interval Potential Survey and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines at 4.

[277] NACE SP0502-2010, Pipeline External Corrosion Direct Assessment Methodology at 6.

Dry gas or dry natural gas means ~~gas with less than 7 pounds of water per million (MM) cubic feet and not subject to excessive upsets allowing electrolytes into the gas stream~~ a gas above its dew point and without condensed liquids.

Electrical survey means ~~a series of closely spaced measurements of the potential difference between two reference electrodes to determine where the current pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline on ineffectively coated or bare pipelines.~~ a cell-to-cell surface potential gradient survey consisting of a series of potential gradients measured along the pipeline, often used on pipelines that are not electrically continuous or on bare or ineffectively coated pipelines in order to detect the probable current discharge (anodic) areas along a pipeline. Where the pipeline is electrically continuous, a close-interval survey and lateral potentials will also detect areas of probable current discharge (anodic areas).

D. PHMSA Should Incorporate by Reference Up-to-Date Editions of Industry Standards.

Standards-developing organizations such as ASME and NACE continually devote resources to reviewing and updating recommended practices, standard practices, and specifications to reflect improvements in work practices and technological advances. The National Technology Transfer and Advancement Act of 1995 (NTTAA) (Public Law 104-113), signed into law on March 7, 1996, requires federal agencies to use standards such as these wherever possible, which were developed by voluntary consensus standards bodies instead of government-unique standards.

One of the primary objectives of the NTTAA was "to promote the United States technological innovation for the achievement of national economic, environmental, and social goals, and for other purposes." Specifically, the NTTAA recognizes that standards play a key role in technological innovation. The standards-related provisions of the NTTAA's Section 12, Standards Conformity, were enacted in response to concerns that federal agencies were developing government standards when similar or identical standards already existed in the private sector or could be developed in the private sector with appropriate government input.[278]

PHMSA has incorporated consensus standards by reference, but the editions currently incorporated in 49 CFR 192 are in many instances multiple editions behind. While INGAA recognizes that PHMSA needs a reasonable amount of time to review standards prior to their incorporation, the current edition of certain of the standards currently incorporated by reference into PHMSA's regulations is many years out of date. The value of up-to-date standards in

[278] Overman, Joanne, The National Technology Transfer and Advancement Act, 10 Years of Public Private Partnership, ASTM Standardization News, April 2006.

improving work practices and realizing technological advances should create a sense of urgency for their incorporation. In many instances, revisions to standards have been made to address the causes of incidents including those cited by PHMSA. For example, requirements for managing near neutral stress corrosion cracking were added to the 2010 version of ASME/ANSI B31.8S recognizing the need to address near-neutral stress corrosion cracking following a series of incidents in the US and Canada. Unfortunately, the 2004 edition of ASME/ANSI B31.8S is the one currently incorporated by PHMSA. PHMSA has not proposed to incorporate more recent editions in its proposed rule. Incorporation of most recent editions is essential if PHMSA desires to prevent the occurrence of future incidents.

INGAA recommends that PHMSA incorporate the following standards by reference to meet the spirit and intent of the NTTAA, improve pipeline safety in accordance with the stated goals of the NPRM, and prevent future incidents:

- Managing System Integrity of Gas Pipelines; ASME B31.8S - 2012
- Gas Transmission and Distribution Piping Systems; ASME B31.8 - 2012
- Standard Practice – Control of External Corrosion; NACE SP0169 - 2013
- Stress Corrosion Cracking Direct Assessment Methodology; NACE SP0204 - 2015
- In Line Inspection of Pipelines; NACE SP0102 - 2010

XV. PHMSA Failed to Engage in Reasoned Decisionmaking By Not Reconciling the NPRM With Competing Regulatory Requirements and Mandates.

The overall impact of the NPRM is inconsistent with the objectives and regulations of other federal agencies. The NPRM's requirements are at odds with the EPA's objectives to reduce methane emissions and FERC's regulations and mandate to maintain continuity of service to pipeline customers. The NPRM also fails to consider all of the costs that interstate pipelines companies will incur as a result of complying with inconsistent and often times conflicting requirements of federal agencies. The NPRM's failure to consider the objectives of other federal agencies and consult with the Chairman of FERC demonstrates a lack of reasoned decisionmaking, especially when PHMSA could have met its safety obligation through less costly and impactful regulations that are more consistent with other agencies' objectives.

A. The NPRM Violates the Pipeline Safety Act and Fails to Engage in Reasoned Decisionmaking by Failing to Consider the Impacts of Increased Methane Emissions That Would Likely Result from the Implementation of the Proposed Regulations.

The NPRM proposes, as a part of its MAOP verification requirements, that operators perform a spike pressure tests in accordance with new § 192.506 for pipelines that include legacy pipe or that were constructed using legacy construction techniques. NPRM at 20,811 As explained above in Section VII, this proposal will likely result in an unnecessary and avoidable increase in methane emissions because of more frequent blowdowns[279] of pipeline facilities. The failure to appropriately account for the increase in methane emissions is inconsistent with PHMSA's statutory mandate to ensure that any pipeline safety standard is protective of the environment.

The PSA provides that any pipeline safety standard prescribed by PHMSA "shall be designed" to meet two needs: "(i) gas pipeline safety, or safely transporting hazardous liquids, as appropriate; <u>and</u> (ii) <u>protecting the environment</u>."[280] PHMSA has a statutory obligation to ensure that its standards strike an appropriate balance between the prerogatives of safety and environmental protection. The NPRM violates this statutory obligation because PHMSA has failed to consider the environmental impacts of the increased methane emissions that will result from its proposal.

For the past three years, the Obama Administration has consistently directed PHMSA to work cooperatively with other agencies on policies to limit methane emissions from the oil and gas sector. The White House's 2013 Climate Action Plan explicitly directed a specific group of Federal agencies -- that included the Department of Transportation—to develop "a

[279] A blowdown is the act of releasing natural gas from a section of pipeline so that work can be done safely.

[280] 49 U.S.C. § 60102(b) (emphasis added).

comprehensive, interagency methane strategy" and pursue "a collaborative approach" to reducing methane emissions.[281] The Obama Administration followed up in 2014 with a "White House Methane Strategy" that specifically identified a role for PHMSA in reducing methane emissions, "including requiring pipeline operators to take steps to eliminate leaks and prevent accidental releases of methane."[282]

In 2015, the White House announced a goal of cutting methane emissions from the oil and gas sector by 40-45 percent from 2012 levels by 2025, along with a series of actions to put the United States on the path to achieving this goal.[283] Among the announced actions was to "Reduce Methane Emissions while Improving Pipeline Safety."[284] The Obama Administration specifically noted the relevance and role of the upcoming NPRM, stating that "[w]hile the [pipeline safety] standards will focus on safety, they are expected to lower methane emissions as well."[285]

Earlier this year, EPA issued the "OOOOa Rule."[286] Under the terms of the OOOOa Rule, regulated oil and gas sector facilities are required to adopt the "best system of emission reduction" that is "adequately demonstrated" to reduce methane emissions.[287] According to EPA, the OOOOa Rule is expected to prevent 300,000 tons of methane emissions annually by 2020 and 510,000 tons of methane emissions annually by 2025 from the oil and gas sector.[288]

Emissions data collected and made public by the EPA through the Greenhouse Gas Reporting Program show that blowdowns are the second largest source of methane emissions for the transmission segment. See Figure 1 below.

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[281] *See* Executive Office of the President, The President's Climate Action Plan at 10 (June 2013), https://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

[282] The White House, Climate Action Plan Strategy to Reduce Methane Emissions at 10 (Mar. 2014), https://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.

[283] The White House, FACT SHEET: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions (Jan. 14, 2015), https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

[284] The White House, FACT SHEET: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions (Jan. 14, 2015), https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

[285] The White House, FACT SHEET: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions (Jan. 14, 2015) (emphasis added), https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

[286] Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35,824 (June 3, 2016). Additionally the OOOOa Rule sets volatile organic compound standards for the oil and gas sector.

[287] Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35,824, 35,828 (June 3, 2016).

[288] Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 81 Fed. Reg. 35,824, 35,827 (June 3, 2016).

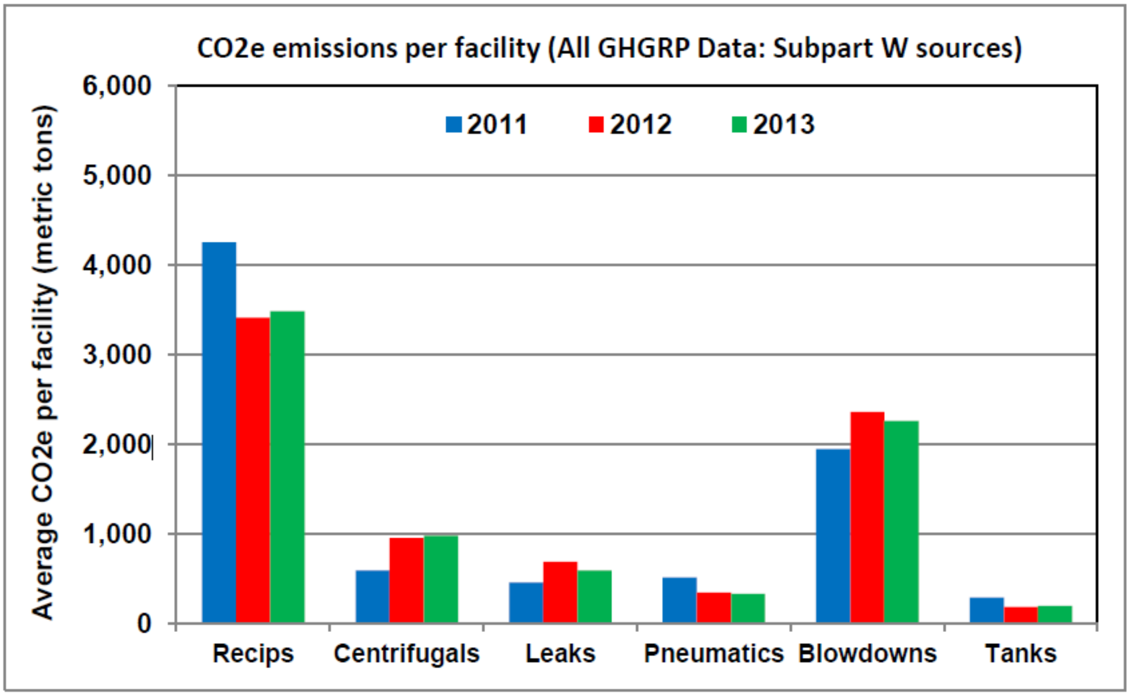

Figure 1. Transmission segment emissions by Subpart W source type (EPA data).

PHMSA was put on notice about the imperative to ensure that the NPRM would not needlessly increase methane emissions. PHMSA's proposal to require increased hydrostatic testing of legacy lines actually threatens to *increase* methane emissions from the pipeline sector by unnecessarily requiring a large number of pipeline blowdowns, each of which would result in significant but avoidable methane emissions.

Notwithstanding its statutory obligation to balance safety and environmental protection, PHMSA's proposal includes no meaningful analysis of whether it could achieve its safety goals in ways that would minimize blowdowns. This and other aspects of the NPRM are directly contrary to the Administration's methane emission reduction goals and violates PHMSA's statutory mandate.

PHMSA also has failed to adequately consider the environmental consequences of its legacy pipeline blanket hydrostatic testing proposal under APA requirements.[289] Commenters in the ANPRM called the issue of excessive blowdowns to PHMSA's attention. The NPRM repeats EDF's comment that the uncontrolled blowdown of 182,000 miles of gas transmission pipeline would be approximately equivalent to the annual greenhouse gas release from 9-14 million autos. The NPRM fails to substantively address these comments. PHMSA states only

[289] *See* 5 U.S.C. § 553 (2012); *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29 (1983).

that "[w]ith regard to the EDF comment regarding the environmental cost due to gas blow down during pressure testing, PHMSA considered this in the rule development. The proposed rulemaking is written to minimize pressure testing." NPRM at 20,791. With respect to legacy pipeline, the NPRM does not "minimize" pressure testing; it actually mandates it. The NPRM's proposal to require spike hydrostatic testing of legacy pipe is flawed and violates PHMSA's statutory mandate to ensure that its pipeline safety standards not only enhance safety but also are protective of the environment.

B. PHMSA Failed to Engage in Reasoned Decisionmaking By Not Acknowledging Pipelines' Obligations under the NGA and Related FERC Requirements.

The NPRM fails to consider the numerous statutory and regulatory obligations of interstate pipelines, which are subject to the NGA's requirements and FERC's regulations. The NPRM does not address the increased costs of compliance with the NPRM requirements, including the costs of reservation charge credit payments that must be paid by the pipeline when service is disrupted for compliance with the proposed rule. The NPRM also fails to consider that FERC approval may be necessary if, as a result of the NPRM, a pipeline has to alter, improve, or remove from service pipeline facilities.[290] If the pipeline is prevented from abandoning facilities, the pipeline may be required to undertake an expensive replacement of facilities that is not reflected in the PRIA. Finally, the NPRM ignores the way that FERC's regulatory regime governing how pipelines make decisions to upgrade or expand their systems, including decisions regarding whether an operator can utilize existing capacity or to expand compression and/or pipeline facilities.

1. The NPRM Fails to Consider That FERC Requires Pipelines to Provide Reservation Charge Credits during Service Outages, and That These Credits May Not Recovered in the Pipelines' Rates.

A pipeline's firm transportation customers are required to pay "demand" or "reservation" charges in order to secure the right to call upon the pipeline for a guaranteed level of transportation service on the pipeline on any day. A firm customer must pay these charges regardless of whether or what level of service the customer requests on any given day. If a pipeline is unable to provide transportation service because a pipeline has been taken out of service for testing, the pipeline is required to credit those charges back to the firm transportation customer that was unable to receive service.[291] A pipeline may not ever be permitted to recoup these charges.

[290] PHMSA should be aware that new pipeline construction is coming under intense public scrutiny, so justifying the replacement of pipelines from an environmental or a cost perspective is more difficult today than it has been historically.

[291] FERC's policy regarding reservation charge crediting "is that where scheduled gas is not delivered due to a non-force majeure or planned maintenance event, there must be a full reservation charge adjustment as to the undelivered amount." *Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272, at P 63 (2006).

The NPRM's proposed requirement will require pipelines to take the pipelines out of service for testing or other compliance activities. The pipeline may also be required to keep the line out of service to perform required repairs. In these circumstances, the pipeline is liable for reservation charge credits—essentially paying customers for the lost ability to transport gas on the pipeline during the service outage. PHMSA does not take this requirement into account in its cost benefit analysis or in any other portion of the NPRM.

2. The NPRM Fails to Consider That Pipelines May Need FERC Approval Before Undertaking Required Repairs or Improvements.

If a pipeline is required to make alterations or improvements to portions of its system for safety or compliance reasons, the pipeline may need to seek authorization from FERC under Section 7 of the NGA.[292] While in some cases, FERC regulations provide for the replacement of facilities without prior approval from FERC,[293] in many cases, particularly if the cost of the replacement is high, if new right-of-way is required, or if previously-undisturbed areas are needed, then the pipeline company will need to seek prior approval for the construction work from FERC. The process before FERC for obtaining approval to construct a pipeline facility is extensive and time-consuming. The time period mandated in the NPRM for certain compliance activities does not account for the added time required for seeking and obtaining FERC approval.

Even in circumstances in which prior FERC authority is not required before undertaking repair or replacements projects, the other federal and state requirements must still be met. In many cases this means the pipeline company will still need to obtain CWA Section 402 and Section 404 authorization from the state and U.S. Army Corps of Engineers. The state is likely to have additional state-specific requirements that the pipeline is also encouraged to meet. Obtaining all of these authorizations takes substantial time that the NPRM has not considered.

The NPRM simply fails to consider FERC's application and environmental review timeline in requiring a pipeline to conduct remedial actions within the required timeframe. A pipeline company that cannot obtain the necessary authorization in the allowed time could be liable for non-compliance. PHMSA should properly consider the FERC approval timeline and take it into account in the final rule.

[292] 15 U.S.C. § 717f(c)(1)(A) (2012). For projects less than $11,600,000, a pipeline company may construct the facilities under FERC's automatic blanket certificate regulations without prior FERC approval. 18 C.F.R. § 157.203(b). For projects over $11,600,000 and below $32,800,000, a pipeline company may construct the facilities after a 60-day prior notice application before FERC. *Id*. § 157.203(c). For projects above $32,800,000, or for a prior notice application that is protested, a full NGA Section 7(c) application and proceeding is required. *See id.* § 157.208(d); *see also Nat. Gas Pipelines; Project Cost and Annual Limits*, 154 FERC ¶ 62,103 (2016) (the cost limitations are adjusted for inflation each year in FERC Docket No. RM81-19-000).

[293] *See* 18 C.F.R. § 2.55(b) and 18 C.F.R. Part 157.

3. The NPRM Fails to Consider That Pipelines Need FERC Approval Before Permanently Removing Facilities From Service.

The results of the testing required by the NPRM could require a pipeline to remove facilities from service. Any such abandonment of facilities and services requires authority from FERC or, if abandonment is not granted, very expensive replacement, which would also likely require FERC approval. The NPRM fails to consider that "continuity of service" is one of FERC's core regulatory objectives, and that FERC has frequently denied applications to abandon pipeline facilities if the proposed abandonment is protested by even a firm customer.

FERC has explained that in considering the criteria for abandonment under NGA Section 7(b) two principles apply: "(1) a pipeline which has obtained a certificate of public convenience and necessity to serve a particular market has an obligation, deeply embedded in the law, to continue to serve; and (2) the burden of proof is on the applicant to show that the public convenience or necessity permits abandonment, that is, that the public interest will in no way be disserved by abandonment."[294] FERC has explained that when the facilities "at issue are certificated facilities and [the pipeline company] uses them to provide jurisdictional interstate transportation services, [the pipeline company] has 'an obligation, deeply embedded in the law, to continue service' on these certificated facilities."[295] Under this rationale, FERC has declined grant abandonment authority if customers on the subject facilities object.[296]

If FERC does not authorize abandonment, the pipeline is forced to either continue to operate pipeline facilities that do not meet PHMSA's standards, or undertake extensive and expensive replacement projects that, due to their high costs, FERC may not authorize because it would not meet the public convenience and necessity standards of Section 7(c) of the NGA described above. While pipeline companies may, under NGA Section 4,[297] seek to recover its costs of an expensive replacement project in a rate case, those costs may only be recovered prospectively. In a competitive pipeline market in which pipelines are forced to discount their rates in order to retain customers, the company undertaking expensive repairs may never be able to recover repair costs from its customers. The NPRM fails consider these unintended consequences.

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[294] *See Trunkline Gas Co., LLC*, 147 FERC ¶ 61,041, at P 6 (2014); *see also, Mich. Consol. Gas Co. v. Fed. Power Comm'n*, 283 F.2d 204 (D.C. Cir. 1960).

[295] *Gulf S. Pipeline Co., LP*, 145 FERC ¶ 61,236, at P 55(2013) (citing *Mich. Consol. Co. v. FPC*, 283 F.2d at 214), *reh'g denied*, 154 FERC ¶ 61,219 (2016).

[296] *See, e.g., Gulf S. Pipeline Co., LP*, 145 FERC ¶ 61,236, at P 55(2013), *reh'g denied*, 154 FERC ¶ 61,219 (2016).; *S. Natural Gas Co*., 126 FERC ¶ 61,246 (2009); *Transcontinental Gas Pipe Line Corp.*, 103 FERC ¶ 61,118 (2003); *Transcontinental Gas Pipe Line Corp.*, 110 FERC ¶ 61,337 (2005).

[297] 15 U.S.C. § 717c (2012).

4. The NPRM Ignores That FERC Regulatory Regime Governs the Way Pipelines Respond to Increased Demand.

The NPRM recognizes many of the market factors that have led to an increased demand for natural gas. NPRM at 20,725-26. However, the NPRM incorrectly ignores key aspects of FERC's regulation of interstate natural gas pipelines that governs the way that pipelines respond to this increased demand. The NPRM states that "[b]uilding new infrastructure, or replacing and modernizing old infrastructure, is expensive and requires a long lead-time for planning." NPRM at 20,726. The NPRM acknowledges that the market often first turns to existing available capacity and then compression expansions to meet its needs before building new pipelines, and asserts that this is done because it is the "most inexpensive way to move new production to demand centers." NPRM at 20,726. The NPRM disregards that FERC's statutory and regulatory framework, not just cost considerations, determines how and when interstate natural gas pipelines are built, expanded, or upgraded.

Pursuant to the Natural Gas Act, FERC has authority over the siting of interstate pipeline facilities and the rates, terms, and conditions governing interstate pipeline transportation service. FERC's statutory and regulatory framework incentivizes market participants to utilize existing capacity and to make significant expansions to infrastructure only when FERC determines, through the certificate process, that such expansions are in the public convenience and necessity. These incentives come in the form of FERC's open access policies, FERC's requirements that interstate pipelines provide firm transportation services, FERC's ratemaking policies, and FERC's environmental review and requirement for market support for major expansion projects.

Under FERC's Order No. 436,[298] interstate pipelines must offer open access transportation service to shippers. A shipper may choose to purchase existing available capacity rather than sponsor an expansion project. A pipeline cannot withhold existing, available capacity from market participants that wish to purchase it at the recourse rate.[299] FERC's regulations also

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[298] *Regulation of Natural Gas Pipelines After Patrial Wellhead Decontrol*, Order No. 436, FERC Stats. & Regs., Regs. Preambles 1982-1985 ¶ 30,665 (1985), *corrected*, FERC Stats. & Regs., Regs. Preambles 1982-1985 ¶ 30,669, *modified*, Order No. 436-A, FERC Stats. & Regs., Regs. Preambles 1982-1985 ¶ 30,675 (1985), *modified further*, Order No. 436-B, FERC Stats. & Regs., Regs Preambles 1986-1990 ¶ 30,688 (1986), *reh'g denied*, Order No. 436-C, 34 FERC ¶ 61,404 (1986), *reh'g denied*, Order No. 436-D, 34 FERC ¶ 61,405, *reconsideration denied*, Order No. 436-E, 34 FERC ¶ 61,403 (1986), *vacated and remanded sub nom., Ass'n Gas Distris. v. FERC*, 888 F.2d 136 (D.C. Cir. 1989), *readopted*, Order No. 500-H, FERC Stats. & Regs., Regs. Preambles 1986-1900 ¶ 30,867 (1989), *reh'g granted in part and denied in part*, Order No. 500-I, FERC Stats. & Regs., Regs. Preambles 1986-1900 ¶ 30,880 (1990), *aff'd in part and remanded in part*, *Am. Gas Ass'n v. FERC*, 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991), *order on remand*, Order No. 500-J, FERC Stats. & Regs., Regs. Preambles 1991-1996 ¶ 30,915 (1991), *further order on remand*, Order No. 500-K, FERC Stats. & Regs., Regs. Preambles 1991-1996 ¶ 30,917, *reh'g denied*, Order No. 500-L 55, 55 FERC ¶ 61,489 (1991).

[299] *See ANR Pipeline Co.*, 98 FERC ¶ 61,175, at p. 61,652 (2002) (citing *Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, 90 FERC ¶ 61,109 (2000)) ("[T]he shipper can always obtain available capacity at the commission – determined just & reasonable recourse rate.").

require interstate pipelines to offer firm service. Firm service is defined by section 284.7(3) of FERC's regulations as service that is not subject to a prior claim by another customer or class of service and receives the same priority as any other class for firm service. 18 C.F.R. 284.7(3). FERC requires firm service to be provided 365 days a year, and has concluded "that the public interest requires that pipelines exercise the highest possible standard of care to ensure the reliability of primary firm transportation service in order to minimize harm to the public and financial injury caused by outages of that service."[300] The NPRM claims that the United States' pipeline network is underutilized, but does not acknowledge that existing capacity may be fully subscribed under firm service, even if the actual usage rates are below 100%. Regardless of a pipeline's design capacity, the actual utilization of a pipeline system on any given day will fluctuate depending on a number of variables, including weather, customer usage, external market dynamics, and maintenance and repair activities. Utilization below 100% does not suggest that capacity is available for other uses.

FERC's ratemaking policies encourage the market to utilize existing infrastructure. Interstate pipelines generally charge cost-based rates for transportation services, and the development of those rates are based in part upon the billing determinants, or capacity, subscribed or used on the system. Additionally, FERC's 1999 Certificate Policy Statement, which addresses the rates for new or expanded pipeline facilities, favors incremental rates for expansion projects, rather than rolling the expansion costs into the rates of existing pipeline customers.[301] This policy is designed to ensure expansion projects are not subsidized by existing shippers and sends proper price signals regarding the market's need for the project. This policy helps the Commission ensure that that expansion projects are in the public interest.[302]

Finally, interstate natural gas pipelines receive certificates of public convenience and necessity from FERC authorizing the construction and operation of a pipeline facility. In order to meet the public convenience and necessity, a project must satisfy FERC's rigorous environmental review. FERC's environmental review generally favors minimized impacts on the environment, such as utilizing existing right-of-way. Once approved, the pipeline must be

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[300] *Tex. E. Transmission, LP*, 149 FERC ¶ 61,143, at P 72 (2014) (citing *Center Point Energy Gas Transmission Co., LLC*, 144 FERC ¶ 61,195, at P 62 (2013)).

[301] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227, *corrected by*, 89 FERC ¶ 61,040 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

[302] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227, *corrected by*, 89 FERC ¶ 61,040 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement). *See also N. Nat. Gas Co.*, 155 FERC ¶ 61,264, at P 8 (2016) ("The Certificate Policy Statement establishes criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. . . . The Commission's goal is to give appropriate consideration to the enhancement of competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.").

capable of meeting the peak demand of shippers who have contracts with the pipeline to receive firm transportation service.

PHMSA fails to consider that FERC's regulatory regime governs the way that interstate pipelines respond to the increased demand for natural gas, including decisions to upgrade or expand their systems. In its final rule, PHMSA must consider this influence.

XVI. PHMSA's Cost Benefit Analysis in the Preliminary Regulatory Impact Assessment Is Fatally Flawed and Does Not Support the Proposed Regulations. PHMSA's Obligation to Conduct a Cost Benefit Analysis

A. PHMSA's Obligation to Conduct a Cost-Benefit Analysis

PHMSA must conduct a cost-benefit analysis that complies with the 2011 Act, APA, and Executive Order 12866. The 2011 Act requires PHMSA to conduct a risk assessment for each standard it issues, and as part of each risk assessment, to consider the "reasonably identifiable or estimated" benefits and costs expected to result from implementation or compliance with the standard.[303] PHMSA may not propose a standard without making a "reasoned determination that the benefits of the intended standard justify its costs."[304] The APA requires reviewing courts to hold unlawful and set aside agency action, findings, and conclusions found to be "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law."[305] Executive Order 12866 also directs federal agencies to assess the benefits and costs of "significant regulatory actions," and assess the benefits and costs of alternatives for rules expected to have an annual impact on the economy of $100 million or more.

When an agency issues a rule based on a cost-benefit analysis that contains a "serious flaw," courts may strike down the entire rule.[306] Examples of such cases are discussed in Section D below. Courts have in several instances struck down rules when the agency failed to consider factors in its cost-benefit analysis that, based on reasonable estimates, would result in substantially greater costs or fewer benefits than were estimated in the agency's analysis. Courts have also struck down rules when their underlying cost-benefit analyses were based on false assumptions or otherwise irrational methodologies.

INGAA retained Process Performance Improvement Consultants, LLC ("P-PIC"), an independent consulting firm, to prepare a Cost Analysis ("INGAA Cost Analysis") that estimates costs of compliance with the NPRM. The Cost Analysis is attached to these Comments as Attachment 6. P-PIC worked closely with the representatives from INGAA's members to develop the cost estimates which are provided below and in Attachment 6, based on past experience for how the proposed regulations would be implemented. INGAA believes that its cost estimates, which are based on operator experience, are more reliable than the regulator's

[303] 49 U.S.C.A. § 60102(b)(2)(D-E).

[304] *Id*. at § 60102(b)(5).

[305] 5 U.S.C. § 706(2)(A).

[306] *Nat'l Ass'n of Home Builders v. E.P.A.*, 682 F.3d 1032, 1040 (D.C. Cir. 2012).

estimates, which rely on the regulator's "best professional judgment." PHMSA does not have reliable data and experience on the costs of many of the activities required by the NPRM.

The PRIA grossly underestimates the costs of its proposed standards and overestimated their benefits. Assuming a 7% discount rate, PHMSA estimates the cumulative annual costs of its proposed standards to be $39.8 million.[307] PHMSA compares these figures to cumulative annual benefits of between $215.6 million and $249.2 million at a 7% discount rate.[308] These estimates simply are not reasonable. INGAA estimates that the proposed standards will have far greater costs, and fewer benefits, than PHMSA predicts. Specifically, INGAA forecasts that, at a 7% discount rate, the proposed standards will cost the industry at least $2.7 billion annually, and the benefits will be lower than PHMSA's estimate. The INGAA cost figure is driven in large part by the cost of response conditions in HCAs and non-HCA areas (Topic 2), a cost PHMSA did not factor into the PRIA. INGAA's cost estimate does not include a recalculation of the Social Cost of Methane.

PHMSA's estimates result from its use of incorrect methodologies to calculate the costs and benefits, reliance on unsupported assumptions to calculate the rules' costs and benefits, and the failure to consider certain costs the proposed standards would impose. A summary of the specific errors in the PRIA's calculation of costs and benefits are provided in Sections B and C below, with the specific descriptions the INGAA Cost Analysis provided as Attachment 6. Given the short comment period as compared to the large scope of the NPRM and the extensive nature of the PRIA, INGAA has developed alternative, realistic cost information to the best of its abilities. Had PHMSA granted INGAA and other stakeholders the additional time requested, more refined cost/benefit estimates could have been provided.

Table C summarizes the estimated costs upon which PHMSA relied in the PRIA, and compares these with INGAA's calculations. The major discrepancies are in the PRIA's first four topic areas: (1) Integrity Assessment and Remediation for Segments outside High Consequence Areas (HCAs) and to Reconfirm MAOP; (2) Integrity Management Program Process Clarifications; (3) Management of Change; and (4) Corrosion Control.

Table C: Summary Critique of PHMSA Methodology and Annual Cost/Benefit Estimates with an 7% Discount (Note: n.e. means not estimated)

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[307] PRIA at Table ES-6.

[308] *Id*.

NPRM Requirement Area	Primary PHMSA Assumptions	PRIA Estimated Benefits	PRIA Estimated Costs	Critique of PHMSA Assumptions	Estimated Costs
1. Reconfirm MAOP, Verify Material Properties, and Integrity Assessment Outside HCAs	<u>MAOP</u> ▪ Cost of performing assessments is considered baseline and Considers cost of performing assessments as baseline and subtracts that figure from its cost estimate ▪ Assumes between 94%-95% of interstate HCAs are piggable and between 49%-68% of intrastate HCAs are piggable <u>Assessments</u> ▪ Applies characteristics in HCAs to non-HCAs ▪ Considers cost of performing inspections as baseline and subtracts that figure from its cost estimate ▪ Assumes the cost of identifying MCA is negligible since operators must already identify HCAs	$196M-230.5M	$17.8M	<u>MAOP</u> ▪ Reconfirming MAOP is separate from integrity inspections or repairs. ▪ PT, pressure reduction are only methods with a practical, economically feasible methods to reconfirm MAOP ▪ ECA and Alternate Technology as proposed are impractical ▪ PRIA assumes most mileage will be done using ILI (ECA or Alternative Technology) underestimates PT costs. ▪ Does not take into account replacements versus validations ▪ Does not include mileage for an in-service incidents since last hydrotest was the result of a manufacturing or construction-related crack-related threat <u>Assessments</u> ▪ Underestimates ILI cost per mile ▪ Underestimates cost of PT per mile ▪ Does not consider that most PT mileage in MCA Class 1 and 2 is under ¼ mile ▪ Does not calculate repair costs in MCAs and Class 3 and 4	$864M
2. Field Repair of Damages - (More Timely Repairs)	▪ Assumes no real cost impact from identifying threats, implementing repair criteria, clarifying P&M based on risk assessments and clarifying periodic assessments ▪ Cost were developed for 1-year metal-loss in HCA	n.e.	$2.2M	▪ Operators will have to develop systems to gather and integrate data at significant costs. ▪ PRIA does not account for more than 150,000 response conditions based on the new criteria. ▪ Non-HCA response conditions are not included in the cost estimate. ▪ PRIA does not accurately reflect the number of repairs and replacements based on the new criteria.	$957M
3. Management of Change Process Improvement	▪ Assumes only 20% of operators would need to develop processes to formalize MOC.	$1.1M	$0.7M	▪ Drastically underestimated labor rates and number of hours required. ▪ The number of MOC events is around 1 event per mile. ▪ Operators will incur a cost for an electronic system or upgraded system.	$258M
4. Corrosion Control	▪ Assumes an average backfill length of 500 feet ▪ Assumes CIS considers that annual test station readings of 0.5% of mileage are out of specification ▪ Compliance costs are based on best professional judgment	$5.5M	$6.3M	▪ Underestimates the number of coating surveys per the requirement ▪ Low cost for equipment and surveys throughout section. ▪ Out of specification test station readings are typically 1% ▪ Compliance rates in the PRIA are not reflective of industry.	$672M

B. PHMSA Has Drastically Underestimated the Costs of Complying with the NPRM.

- **Topic Area 1 -- Integrity Assessment and Remediation of Segments Outside High Consequence Areas (HCAs) and to Re-establish Maximum Allowable Operating Pressure (MAOP)**

INGAA's total cost calculations for Topic 1 are compared to the PRIA's estimates in Table 23 of INGAA's Cost Analysis (Attachment 6), which is also provided below:

Table 23: Topic 1 Annual Total Cost

Location	Industry Costs	PHMSA Costs
Interstate and Intrastate		
MAOP Untested HCA> 30% SMYS Mileage	$42,986,592	$2,215,052
MAOP Inadequate Records Mileage	$222,775,872	$10,569,323
MAOP Other Untested: 20-30% SMYS, Class 3&4, MCA Class 1&2	$349,455,322	$4,528,791
MAOP for Reportable In-Service Incidents without PT	$192,881,920	$0
MCA Identification (Interstate and Intrastate)	$86,931,643	$0
MCA Annual Reporting and Recordkeeping	$5,301,720	$0
MCA and non-HCA Class 3 Class 4 Assessments	$429,505,337	$9,511,538
Total	**$1,329,838,406**	**$26,824,704**
3% Discount (15-Yr)	$16,351,790,303.73	$329,838,522
7% Discount (15-Yr)	$12,959,897,611.52	$261,419,294
3% Annualized	$1,090,119,354	$21,989,235
7% Annualized	$863,993,174	**$17,427,953**

- **The PRIA Incorrectly Assumes that Inline Inspection Will Be Used to Reconfirm MAOP, and Does Not Account for All the Costs Associated With MAOP Verification.**

Proposed modifications to section 192.624 would require re-establishment of MAOP for certain pipeline segments. The PRIA provides that to re-establish MAOP, "[t]he primary methods PHMSA expects operators to use would be ILI in conjunction with an engineering critical assessment (ECA) or pressure testing."[309] PHMSA incorrectly assumes in the PRIA that ILI will be used in the majority of instances to reconfirm MAOP under the rule. As explained above in the MAOP Reconfirmation section, ILI (under the methods for either ECA or alternative technology) will not be widely deployed to verify MAOP as PHMSA assumes, because of the burdensome requirements in proposed regulations for obtaining authorization to use ILI for this purpose. If these requirements are adopted, INGAA believes most operators will rely on hydrostatic pressure tests to verify MAOP.

[309] PRIA at 33.

PHMSA assumed that only 5% of lines in Class 1, 2, and 3 areas would be pressure tested to verify MAOP, and that no lines in Class 4 areas would be pressure tested to verify MAOP. The cost of pressure testing is substantially greater than the cost of ILI, as demonstrated in tables 3-9 and 3-18[310] of the PRIA. These tables show that the cost of pressure testing is more than 66 times greater than the cost of ILI. ECA would be more expensive than pressure testing under PHMSA's proposed standards. Under INGAA's proposed revisions, however, ECA plus ILI would be the most cost-effective option for reconfirming MAOP.

INGAA estimates the cost of implementing proposed section 192.624 to be $808 million, based on the assumption that 100% of MAOP verification will be accomplished with pressure tests, because there is no consensus on how ILI with ECA will be formulated.[311]

- **PHMSA's Estimates of the Costs of Pressure Testing Ignore the Higher Costs of Testing Shorter Segments of Pipe.**

In addition to the pressure testing that will be required to comply with proposed section 192.624, the Proposed Rule would require pressure testing that incorporates a spike test for "all gas transmission pipelines constructed before 1970." In addition, the proposed rule would require re-establishment of MAOP for previously untested pipe in HCA operating at greater than 20% SMYS (greater than 30% SMYS is included above), in a Non-HCA within Class 3 and Class 4 locations, and in a MCA within Class 1 and Class 2 (piggable lines only).[312]

PHMSA estimated costs of pressure testing on pipe segments of one, two, five, and ten miles, as shown in Table 3-18 of the PRIA. PHMSA estimates a weighted average cost of pressure testing of $226,939 per mile on interstate pipe and $203,556 per mile on intrastate pipe.[313]

Under the proposed rule, most of the required pressure testing will be on pipeline segments less than one mile in length. For this reason, INGAA estimates pressure testing costs on a per-foot basis. As explained in section VII(G) of these comments, some INGAA members have tentatively reviewed portions of their systems for potential MCAs and where they might need to reconfirm MAOP in those areas. This preliminary review indicates that over 50% of the MCA areas that will require MAOP reconfirmation are short, discontinuous segments less than

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[310] INGAA disagrees with PHMSA's cost estimates for pressure testing, as discussed below.

[311] *See* Table 23 of Attachment 6. This figure is the sum of INGAA's estimated costs of implementing the proposed MAOP requirements discussed therein.

[312] *See* PRIA at 57; Proposed §§ 192.624(c)(1)(ii) and 192.506(a).

[313] *See* PRIA Table 3-19.

1,000 feet long. These costs would far exceed the costs outlined in the PRIA, which are based on longer test segments.

Consistent with PHMSA's calculations, INGAA estimates that the per-unit cost of pressure testing will increase as pipe segments decrease in length. The primary costs associated with pressure testing are mobilization-related. Having to pressure test shorter sections of pipe in MCAs increases the costs dramatically. Based on economies of scale, the per-foot cost of pressure testing decreases as the length of pipe increases. Table D summarizes INGAA's estimated costs of pressure testing by foot.

Table D: Estimated Costs of Pressure Testing by Foot, Broken Down By Cost Components

Component	Average Interstate PT Per Project Cost	Average Intrastate PT Per Project Cost	Average MCA PT Per Project Cost
Material	$233,873	$34,977	$46,991
Construction Contractor	$1,192,176	$205,880	$122,925
Company Cost	$136,240	$15,189	$29,968
Outside Services	$417,736	$43,896	$72,441
ROW Costs	$27,215	$7,445	$6,154
Environmental Costs	$12,059	$3,531	$1,453
Other	$23,667	$2,915	$2,270
Total	$2,042,964	$313,834	$282,201
Avg. Cost per Foot	**$102**	**$163**	**$417**

Source: Operator survey data

The PRIA ignores that under the proposed requirements, the majority of pipe that requiring pressure testing will be less than 0.25 miles in length. As shown in INGAA's Cost Analysis, the unit costs of pressure testing these shorter pipeline segments are drastically higher than the unit costs for longer segments. As a result, PHMSA underestimates the average costs of pressure testing. PHMSA estimates the total annual costs of its proposed pressure testing requirements to be $17 million.[314] INGAA has corrected PHMSA's estimate by factoring in that more pressure testing than PHMSA estimates will be required because ILI cannot currently verify MAOP, considering the greater costs associated with pressure testing pipeline segments shorter than one mile, and based on the projected size and number of MCAs and non-HCA Class 3 and 4. As detailed in the INGAA Cost Analysis, INGAA estimates the total cost of pressure testing under the proposed rules to be **$808 million.**[315] The dramatic difference in estimates is explained by the fact that compared to PHMSA's estimates, more pressure testing

[314] PRIA at 7, Table ES-6.

[315] *See* Attachment 6, Table 23.

will be required because ILI currently cannot verify MAOP and the fact that pressure testing pipeline segments shorter than one mile will be much more costly.

- **PHMSA Inaccurately Estimates GHG Emissions and Associated Costs based on the Social Cost of Methane**

The PRIA underestimates the greenhouse gas emissions ("GHG") that will result from the compliance with proposed section 192.624 and the associated Social Cost of Carbon, and overestimates the GHG emissions the proposed rule will reduce. The error stems from PHMSA's underestimation of GHG emissions from pipe that must be blown down when operators hydrostatically pressure test to reconfirm MAOP. There are at least four flaws in PHMSA's analysis.

First, in the tables in PRIA sections 3.1.4 and 3.1.8, PHMSA vastly underestimates the number of miles that will use hydrostatic pressure testing for MAOP reconfirmation. PHMSA incorrectly assumes in the PRIA Table 3-5 that up to 95% of certain pipeline segments will be assessed using ILI. As explained above, PHMSA's assumptions are faulty. If PHMSA does not adopt the changes that INGAA is recommending to aspects of the proposed rule addressing TVC, MCA and MAOP, PHMSA should instead assume that the vast majority of pipe will be hydrostatically pressure tested. While PHMSA estimates that only 1,047 miles of interstate and intrastate pipe will be pressure tested,[316] INGAA estimates that at least 9,017 miles of interstate and intrastate pipe will be hydrostatically pressure tested and thus blown down.[317]

Second, PHMSA's Equation 1 uses an unrealistic pressure at blowdown conditions.[318] Blowdowns at higher pressure levels result in greater methane emissions. As an example, if an interstate pipeline pressure prior to blowdown is 750 PSI rather than 150 PSI, the blowdown volume will be five times larger than PHMSA's estimate. PHMSA calculates that the blowdowns will occur at 150 PSI for interstate pipelines and 100 PSI for intrastate pipelines, which is unrealistically low for transmission pipelines, that operate at much higher pressures. PHMSA did not consider that pipe may be at full operating pressure when operators blow down. Drawing down the pipeline pressure is not always an option, especially since a pipeline draw down extends the time that the pipeline is out of service. Several factors influence an operator's ability to draw down a section of pipe prior to conducting maintenance or repairs. Those factors include, but are not limited to: whether a single pipeline is being blown down or whether the operator has multiple pipelines adjacent to the line being blown down; overall service disruption time and impacts to customers; time of year; and weather conditions when the blowdown must

[316] PRIA at 63-64, at Table 3-50.

[317] Attachment 6 at Table 1.

[318] PRIA at 37-38.

occur. In general, blowdowns during high winter or summer peak demand periods are undesirable.

Even when operators have time to "draw down" the pipeline pressure using existing compression, the drawdown may only get the line to 350-400 PSI and then the line will be blown down at that pressure. In this pressure range, the blowdown volume will be about 2.5 times larger than PHMSA's estimate. To achieve a lower pressure, the operator must rent an external mounted compressor that typically costs $30,000. Even with additional, rented compression, operators may only reduce line pressure to approximately 150 PSI and blow down the line to the atmosphere from that level. The 150 PSI used by PHMSA in Equation 1 for interstate pipelines is not a realistic assumption.[319]

Third, PHMSA fails to include emissions from segments of pipe which undergo an ILI to reconfirm MAOP and that ILI identifies a repair condition. PHMSA estimates that 10% of the anomalies that are discovered using ILI will have to be repaired by pipe replacement. The replacement of that pipe will require a blowdown and those emissions are not accounted for in the PRIA.

Fourth, the PRIA overlooks that testing a single 200-foot segment would require the operator to blow down the full valve section of that pipe. The PRIA only evaluates emissions of blowdowns on a per-mile basis, and as such, underestimates the quantity of methane released by any tests on segments that are shorter than one mile in length. The PRIA, therefore, underestimates the GHG emissions associated with the testing of small pipeline segments.

INGAA estimates that blowdown of a 10-mile segment of 36-inch pipe at 800 PSI would lead to a release of 20 MMcf of methane. Reducing the pressure of that pipeline segment to 300 PSI for blowdown would lead to a methane release of 7.7 MMcf. PHMSA estimates a blowdown of 150 PSI that leads to a methane release of 4.33 MMcf.

The GHG emissions and Social Cost of Methane calculations in the PRIA must be recalculated to reflect: 1) an accurate estimation of the number of miles that will be blown down and hydrostatically pressure tested; 2) a realistic range of pressures in Tables 3-6 and 3-7; 3) emissions associated with replacements; and 4) that operators will have to blow down entire valve sections of pipe to test single segments, so mileage-based estimates of blowdown costs

[319] PHMSA's Tables 3-6 and 3-7 footnote 4 reflects a 50 PSI assumption. PHMSA's Equation 1, however, reflects an assumption of 100 psi for intrastate pipelines and 150 PSI for interstate pipelines. Based on the volume presented in the tables, it appears footnote 4 is not applied and 150 PSI or 100 PSI was assumed. Regardless, these assumptions are far too low.

underestimate methane released. If a pressure lower than 350-400 PSI is assumed for any of the pipe, the cost to rent additional equipment to draw down the line must also be included.

INGAA did not recalculate the PRIA analysis for the Social Cost of Methane in its entirety, but a primary example of blowdown emission under-estimates can be reviewed as an example considering the methane emissions from pressure testing presented in PRIA section 3.1.8.1. INGAA estimates that 4,177 miles of interstate pipelines and 4,840 miles of intrastate pipeline would be blown down for pressure testing. Using the same weighted mileage ratios as PHSMA from Figure 3-47, and assuming, *on average,* a gas pressure of 400 PSI, INGAA estimates 3,177 MMCF of methane from blowdowns compared to 298 MMCF of methane from Table 3-50 of the PRIA. This is one example where the PRIA significantly under-estimates blowdown emissions. Using a Social Cost of Methane of $25 per MCF per PRIA Table B-2, the incremental associated costs of methane emissions based on INGAA's estimate compared to the PRIA estimate is $72 million. This is in addition to the $2.7 billion in costs that INGAA calculated in Table C above.

- **PHMSA Inaccurately Estimates the Cost of Assessments in Topic 1 and Does Not Account for MCA Identification or Annual Reporting.**

PHMSA does not account for the costs of identifying MCA mileage. These include administrative costs of identifying MCA areas and additional costs of data collection. *See* Section V.G and Attachment 6 at section 1.10 for additional discussion of these costs.

- **Topic Area 2 – Integrity Management Program Process Clarifications**

PHMSA has drastically underestimated the costs of the proposed integrity management program process clarifications. PHMSA recognizes that the proposed regulations would require additional costs compared to existing requirements for response conditions related to metal-loss for one-year conditions, but PHMSA's estimate of costs is significantly lower than the estimates provided by INGAA operators. INGAA estimates the cost of response condition changes, repairs and replacements to be approximately $956 million annually, using a 7% discount rate.

A comparison of PHMSA's and INGAA's total cost estimates in this area is provided in Table 38 of Attachment 6, reproduced below.

Table 38: Topic 2 Annual Total Cost

Location	Industry Annual Costs	PHMSA Costs
Interstate and Intrastate		
Response Conditions, Repair, Replacement	$7,208,449,800	$3,400,000
Data Integration	$406,155,640	-
Total	**$7,614,605,440**	**$3,400,000**
3% Discount Total	$9,920,224,809	$19,400,000
7% Discount Total	$8,530,108,727	$32,700,000
3% Annualized	$1,099,031,726	$1,300,000
7% Annualized	**$956,834,611**	**$2,200,000**

Based on Table 37, 7 year and 15-year calculations, for response conditions, repair, and replacements. Data integration costs are based on Table 28.

In the proposed regulations in Subpart O, PHMSA prescribes requirements for managing pipeline integrity within HCAs. PHMSA includes eight "clarifications" to the IM regulations.[320] INGAA has determined that the following proposed clarifications have the greatest cost implications to industry:

- Clarify threat identification requirements for time-dependent threats [§ 192.917];
- Clarify (and in limited cases, revise) repair criteria for remediating defects discovered in HCA segments [§§192.713 and 192.933]; and
- Clarify requirements for periodic evaluations and assessments, including some specifically for plastic transmission pipelines [§ 192.937]

PHMSA's underestimations of costs for these items are described below. INGAA believes that PHMSA has underestimated costs of the remaining IMP process clarifications as well; however, INGAA has not calculated cost comparisons for these sections and therefore does not delineate PHMSA's specific areas.

- **Data Integration Costs**

Compliance with proposed sections 192.917 and 192.937 will require operators to develop systems to integrate new data elements. Costs of data integration are attributable to one-time set up costs to establish systems for data collection and integration, and annual maintenance and analysis to implement compliance with the new requirements. These costs are significant especially in light of PHMSA's estimate that operators would not incur measurable costs.

[320] PRIA at 69.

For more information on the development of the Total Data Integration Costs please see the INGAA Cost Analysis in Attachment 6, Section 2.1.

- **PHMSA improperly assumes there are no incremental costs associated with response and repair requirements in sections 192.713 and 192.933 by misstating current requirements and industry current practices.**

PHMSA provides in Section 3.1.3 of the PRIA that its intent was to provide an "analysis of the incremental costs of the proposed changes." PHMSA asserts in the same section that the "specific repair criteria proposed by PHMSA do not represent new repair standards."[321] PHMSA states that these requirements are not new "[b]ecause operators must already repair pipeline defects that are injurious to the pipe."[322] INGAA disagrees with PHMSA's assumption that the proposed response and repair criteria represented in section 192.713 are already required. If the response conditions proposed by PHMSA in section 192.713 were already in place, then the proposed conditions would be duplicative and unnecessary and PHMSA would not have been inclined to propose new criteria. INGAA also disagrees with the assumption that the proposed criteria only address injurious defects. In fact, there were previously no specific in-line inspection response condition requirements outside of HCAs. Most of the newly proposed response conditions are not considered injurious by consensus industry standards. Since most of the conditions identified by PHMSA do not represent injurious conditions and are not already required response or repair conditions, INGAA also disagrees with PHMSA's assertion that "[t]he only cost to operators of implementing the repair timeliness criteria is the time cost of money for completing some repair more quickly than an operator might have done prior to this rulemaking."[323]

INGAA urges PHMSA to consider the actual cost of proposed conditions relative to the actual benefits. PHMSA states that "[t]he analysis is based on the assumption that all defects discovered by the testing and assessment requirements would be either repaired or result in an incident."[324] However, INGAA's analysis shows that only approximately 10% of the proposed conditions would result in repair or replacement. In other words, 90% of the proposed conditions would result in no repair or replacement because they are not injurious. Because these conditions are not injurious, they would not have resulted in an incident if not addressed and they are not a good use of public safety expense.

PHMSA has not adequately accounted in the PRIA for the costs of responses, repairs and replacements, based on the proposed response condition criteria, either for its immediate

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[321] PRIA at 32.

[322] *Id.*

[323] *Id.*

[324] *Id.*

condition requirements, one-year conditions, or two-year conditions. INGAA estimates that the costs for responses, repairs, and replacements will total over $7.2 billion based on the assessment period.

- **Topic Area 3 – Manage of Change Process Improvement**

PHMSA proposes to add new section 192.13(d) to impose management of change ("MOC") provisions on all onshore gas transmission pipelines, whereas these requirements previously only applied to pipeline segments in HCAs and control centers. As shown below in Table 43 of Attachment 6, PHMSA has underestimated the costs of its proposed standards.

Table 43: Total MOC Compliance Cost

Element	Industry Cost	PHMSA Cost
Average One-Time Cost of Revising MOC	$34,805,163	$426,281
Annual Cost of Implementing MOC	$296,751,472	$977,760
Total Cost	$354,566,063	$1,404,041
3% Discount (10-Yr)	$2,607,290,756	$12, 448,803
7% Discount (10-Yr)	$2,230,156,232	$9,954,924
3% Annual Cost	$295,534,239	$829,920
7% Annual Cost	$257,820,786	$663,662

Source: RIA and Operator Data

PHMSA claims that, because operators currently apply MOC principles to all of their pipeline systems with varying degrees of formality, there will be limited incremental costs associated with the new requirement to apply MOC to all transmission facilities. INGAA contends there will be significant costs associated with the expansion of MOC requirements to all onshore pipelines. PHMSA has not accurately estimated the costs associated with complying with this expanded requirement. For example, a comparison of PHMSA's estimates of total labor costs in Table 3-66 (based on Bureau of Labor statistics) with the estimates from INGAA operators based on actual experience shows that operators' labor costs will be significantly higher than PHMSA's estimates. Table 39 of Attachment 6 provides INGAA's estimates of hourly labor rates for general engineers, which range from $70.01 to $104.90.

PHMSA's estimates of the number of hours for MOC process development and MOC implementation are unreasonably low. As shown in the INGAA Cost Analysis, INGAA operators estimate that significantly more man-hours are necessary to develop and implement MOC processes.

PHMSA's total annual compliance cost estimate is based on an unrealistic estimate of total annual MOC events. For example, in Table 3-69, PHMSA estimates the total annual compliance costs based on an estimated four MOC events per year. The expansion of the requirement to all onshore pipelines, and not just segments in HCAs, likely would result in operators experiencing more a minimum of 297,790 MOC events per year, or at a minimum one (1) MOC event per mile.

PHMSA estimates that under its proposed standards, the industry's annual MOC compliance costs will be approximately $700,000, at a 7% discounted rate.[325] As shown in Tables 40 and 42 of Attachment 6, applying INGAA's estimate of annual MOC events to INGAA's estimated labor costs and number of hours, INGAA estimates annual compliance costs will be far greater than those estimated by PHMSA. As shown in Table 43 of Attachment 6, INGAA estimates that the annual MOC compliance costs will be at least $257,820,786 annually at a 7% discount rate, with an undiscounted total annual cost of $354,566,063. These numbers do not account for costs of upgrading from a manual to electronic MOC system, which would be necessary to implement the proposed MOC requirements. The need to upgrade to an electronic system would disproportionately affect small pipeline operators, which in many cases do not have electronic systems.

- **Topic Area 4 – Corrosion Control**

PHMSA makes numerous errors in estimating costs of its proposed regulations concerning corrosion control. These are discussed in depth in the INGAA Cost Analysis which calculates the true costs of external corrosion coating surveys, CIS when a test station reading indicates low CP, adding test stations to HCAs, interference current surveys and interference internal corrosion monitoring for CO2, sulfur, water and other chemicals. INGAA calculates that PHMSA has underestimated the costs associated with corrosion compliance by at least $664 million, based on a 7% discount rate. See Attachment 6, Tables 49 and 50.

Table 49: Total Corrosion Compliance Cost

Component	Industry One-Time	Industry Annual	Industry Recurring (7 Years)	PHMSA One-Time Cost	PHMSA Annual	PHMSA Recurring (7 years)
External Corrosion Coating		$840,696,000		-	$298,000	
External Corrosion Monitoring	$29,808,750	$26,364,780		$3,974,492	$6,602,718	
Interference Current Surveys			$5,950,000			$1,829,877
Internal Corrosion Monitoring	$75,500,000	-		$400,000		

[325] PRIA at 7.

Total Cost	$105,308,750	$867,060,780	$5,950,000	$4,374,492	$6,900,718	$1,829,877
3% Discount	$105,308,750	$10,661,442,767	$73,161,635	$4,374,492	$84,851,733	$11,742,668
7% Discount	$105,308,750	$8,449,913,073	$57,985,534	$4,374,492	$67,250,726	$10,552,056

Source: PRIA and Operator Data
1. One-time cost in year 1; annual costs in years 1-15 years; and 7-year recurring costs annualized over 7 years.

The total present value for industry versus PHMSA costs are reflected in Table 50.

Table 50: Present Value Cost, Topic Area 4

	Total 7%	Average Annual (7%)	Total 3%	Average Annual (3%)
Industry Costs	$8,613,207,357	$672,501,990	$10,839,913,152	$820,949,043
PHMSA Costs	$94,788,018	$6,319,201	$118,451,243	$7,896,750

4.1. External Corrosion Coatings

Proposed section 192.319(d) would require a coating survey be conducted using either ACVG or DCVG for all new onshore steel transmission pipelines with prescriptive repair criteria. Proposed section 192.461(f) would require a coating survey be conducted using either ACVG or DCVG whenever a repair is made that results in more than 1000 feet of backfill with prescriptive repair criteria. The PRIA estimates coating survey costs at between $2,000 and $50,000 per mile.[326]

PHMSA assumes that an average survey length of 500 feet of survey will be required for repairs for purposes of the PRIA, but the NPRM requires coating surveys for repairs 1,000 feet or greater. This is internally inconsistent and results in the PRIA underestimating the costs of coating surveys, even by its own standards.

As applied, the proposed regulations will require coating surveys for new pipelines and HCAs to be significantly longer than 1,000 feet. PHMSA estimates that the proposed rule would require 240 surveys, at a cost of between $200 and $5,000 per mile, depending on class area. PHMSA provides no cost estimates for coating surveys required for new pipelines or for periodic coating surveys for HCAs. PHMSA does not consider any of the costs of excavation and required coating repairs in its cost estimates. PHMSA thus estimates the costs of external corrosion coatings to be only $298,000.[327]

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[326] PRIA at 86.[327] PRIA at Table 3-71.[328] *See* Attachment 6, Table 49, Row 1.

[327] PRIA at Table 3-71.[328] *See* Attachment 6, Table 49, Row 1.

These are significant underestimates. INGAA estimates that 5,532 miles of surveys would be required annually, with an average survey cost of $3,000/mile. In addition, PHMSA failed to account for the cost to remediate any anomalies. Based on corrected assumptions using operator data, INGAA calculates that the costs of external corrosion coating surveys will be $840.7 million annually.[328]

4.2. External Corrosion Monitoring Close Internal Survey

Proposed section 192.465(f) would require a close internal survey (CIS) – in both directions of a test station – when a test station reading indicates low cathodic protection (CP). INGAA assumes that an average of one mile would need surveying once an out-of-compliance test point is identified. Following remediation, this entire area would require CIS to confirm restoration of adequate cathodic protection.

The PRIA reports a 0.5% out-of-compliance rate. INGAA questions this assumption, based on operator survey data. INGAA assumes a more typical value of 1% of test stations that do not meet CP criteria in Appendix D. In addition, section 192.935(g)(2)(iv)(A) requires periodic CIS in HCAs every seven years, which is not considered in the PRIA. As such, the total costs estimated in the PRIA do not reflect the imposed costs of the proposed changes. As shown in Attachment 6, Section 4.2, INGAA estimates a total cost of external corrosion CIS under proposed section 192.465(f) to be $26 million. This far exceeds PHMSA's estimate of $6.6 million.[329]

4.3. Cost of Adding Test Stations in HCAs

The proposed rule would require pipe-to-soil tests at half-mile intervals within each HCA segment. Currently industry has a least one station within a one-mile interval. For cost development, INGAA uses the estimate of new stations needed according to the PRIA Table 3-73. PHMSA estimates the cost to add a test station at $500; industry assumes an average of $3,500.[330] INGAA estimates the total costs of adding test stations in HCAs to be approximately $29 million, compared to PHMSA's estimate of approximately $4 million.[331]

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[328] *See* Attachment 6, Table 49, Row 1.

[329] *See id*. at row 2.

[330] *See* Attachment 6 at Table 46.

[331] *See id*.

4.4. Interference Current Surveys

Proposed section 192.473(c) would require interference current surveys if stray current are found in HCAs. Proposed section 192.935(g)(1) would require periodic surveys whenever needed, but not to exceed every seven years. For simplicity, PHMSA assumed a seven-year survey interval for the periodic requirement in section 192.473(c).

PHMSA estimates the costs of these ICS requirements at $1.8 million. However, PHMSA does not include several cost drivers of the proposed requirements and inappropriately applies a compliance factor. PHMSA does not consider any of the costs of remediation of AC stray current to excessively conservative current density criteria in its cost estimates. Industry consensus standards consider AC densities 100 A/m^2 to be corrosive and uncertain range to be between 30 A/m^2 and 100 A/m^2. PHMSA's prescriptive criteria of 20 and 50 A/m^2 are not supported by research and experience.

For calculation purposes, INGAA's cost estimates utilize the incremental need for survey rate reported in Table 3-74 of the PRIA. As shown at Table 50 in Attachment 6, Section 4.4, INGAA estimates the costs of the ICS rules to be approximately $6 million, far in excess of PHMSA's estimated cost of approximately $1.8 million.[332]

4.5. Internal Corrosion Monitoring

Proposed section 192.478 includes new requirements to address internal corrosion, including evaluating the partial pressure of corrosive constituents, use of gas-quality monitoring equipment, and semi-annual evaluations of gas quality and semi-annual monitoring and mitigation program evaluations. Proposed section 192.935(f) provides a lengthy list of requirements for addressing internal corrosion in HCAs. PHMSA proposes that operators install continuous monitoring systems at each pipeline receipt point "where gas with potentially deleterious contaminants enters the pipelines."

The proposed rule would require internal corrosion monitoring for carbon dioxide, hydrogen sulfide, sulfur, microbes, water and other corrosive constituents. The PRIA states that the entire cost of this requirement would be "either nothing or relatively inexpensive,"[333] and, based on a cost of $10,000 for each monitoring system, estimates this cost at $400,000 for all of the industry.[334]

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[332] *See* Attachment 6, Table 49 at row 3.

[333] PRIA § 3.4.4.4.

[334] *Id*. at § 3.4.4.5.

This is an unreasonable underestimation of the costs of this requirement. Each continuous monitoring system would cost approximately $275,000, and an individual pipeline may have over one thousand receipt points. In addition, the current compliance rates are not applicable. Therefore, INGAA calculates the costs using the total number of monitors needed according to PHMSA, without applying the compliance factor. INGAA's cost calculations for the proposed internal corrosion monitoring requirements far exceed PHMSA's estimates. While PHMSA estimates total costs only at $400,000, INGAA has calculated that these costs will amount to a $75.5 million one-time cost.[335]

4.6. Other Uncaptured Costs

Proposed changes to the corrosion control requirements in the NPRM will mandate additional costs for a number of items that are not captured, including:

- Changes to prompt remedial action timeframes in HCAs and outside HCAs
- Semi-annual internal corrosion monitoring and mitigation program reviews
- Data integration
- Cost of documenting compliance to the additional requirements

INGAA did not have time to estimate total costs of these items. INGAA notes, however, that these costs will be significant, and that PHMSA has further underestimated costs of its proposed corrosion control requirements by ignoring these costs completely. As demonstrated by Tables 49 and 50 of Attachment 6, PHMSA has disregarded several costs of its proposed corrosion compliance requirements, and underestimated the total costs of its proposed standards by at least $664 million annually.

➢ Additional Costs Associated with FERC Regulation

PHMSA does not account in the PRIA for its requirements' triggering of additional costs of compliance with FERC requirements. The PRIA ignores that FERC requires interstate natural gas pipelines to provide demand charge credits to customers when firm transportation services are disrupted, including when the disruption is caused by testing and repairs. Given the scope of the proposed rule, the potential for pipelines to incur demand charge credits is likely to be substantial. Gas drawdowns required for MAOP testing in compliance with section 192.624 will extend the duration of outages and service interruption, further adding to these costs. The Proposed Rule also fails to consider that FERC approval may be necessary if, as a result of the NPRM, a pipeline has to alter, improve, or remove from service pipeline facilities. If FERC does not permit a pipeline to abandon facilities that cannot be brought up to the new

[335] *See* Attachment 6, Table 49 at row 4.

requirements in a cost-effective manner, the pipeline may be required to undertake an expensive replacement of facilities. The PRIA does not reflect the additional compliance costs that may be required to satisfy FERC's regulations.

C. PHMSA Has Overestimated the Benefits of the NPRM.

While INGAA recognizes that portions of the NPRM will provide additional safety benefits, PHMSA has overestimated the benefits achievable from the proposed regulations. The PRIA based its benefits estimates on pipeline incidents that may be avoided through compliance with the proposed requirements.

The PRIA includes several errors that have resulted in an overestimation of benefits. First, PHMSA based its incidents averted rate on data from the past 13 years. This is unreasonable, given the substantial change in pipeline safety practices that have occurred over that time period. Because it considers incidents that occurred as far back as 2003, before these positive pipeline safety developments occurred, PHMSA's baseline estimate of incidents averted is skewed to overestimate the likelihood of future incidents. A more reasonable estimate of benefits would be based on the most recent five-year period, to reflect the positive pipeline safety developments that have occurred since 2003 pursuant to PHMSA's regulations.

PHMSA's discovery rate is based on an analysis of immediate and scheduled repairs using outdated 2004 to 2009 data. Based on the 2014 and 2015 average failure rates, the average pressure test failure rate is closer to 0.021 incidents per mile. PHMSA also incorrectly assumes that once a discovery is made by pressure test, between 33 and 50% will fail. This is not a realistic rate and is unsubstantiated by the data. Indeed PHMSA's spike test requirements will actually unnecessarily inflate the failure rate without adding a margin of safety.

The PRIA also considered benefits from improving the safety of pipelines to which its proposed regulations do not apply. The PRIA explains that in addition to basing its incidents averted rate on reported gas transmission incidents, "PHMSA used data from the hazardous liquid" reports.[336] PHMSA's proposed rule, however, does not apply to hazardous liquids pipelines. It is unclear why PHMSA considered data from hazardous liquids pipelines to calculate benefits of a rule that does not apply to such pipelines. The PRIA does not explain why, rather than basing its assessment of benefits on benefits that would result from its proposed regulations, it opted to calculate these benefits using more general hazardous liquid and natural gas data.

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[336] PRIA at 119.

INGAA recognizes that PHMSA's proposed standards will have benefits. However, PHMSA has made errors in calculating these benefits, and as a result has overestimated them. Furthermore, these benefits can be achieved more efficiently through alternative means INGAA has proposed.

D. Agency Cost-Benefit Analyses May Not Ignore Significant Costs or Benefits or Rely on Patently Incorrect Assumptions.

The U.S. Court of Appeals for the District of Columbia Circuit has explained that a "serious flaw" undermining a cost-benefit analysis "can render the rule unreasonable."[337] Courts have on several occasions rejected agency rulemakings that relied on faulty cost-benefit analyses, particularly when an agency fails to consider relevant factors that, if adequately considered, would significantly alter the costs or benefit of the proposed rule. An agency's reliance on analytic assumptions that lack support in the record has similarly led to the striking down of a rule.

1. An Agency's Cost-Benefit Analysis May Not Ignore Significant Costs or Benefits Likely to Result from a Rule.

An agency's cost-benefit analysis that ignores major costs or benefits of a rule is arbitrary and capricious.[338] In *Business Roundtable v. SEC*, the D.C. Circuit struck down a rule promulgated by the U.S. Securities and Exchange Commission ("SEC") for the agency's failure to consider relevant cost-drivers in the statutorily-required cost-benefit analysis.[339] The governing statutes required the SEC to consider the effect of rulemakings on "efficiency, competition, and capital formation."[340] This requirement was understood to place upon the agency a "statutory obligation to determine as best it can the economic implications" of its proposed rules.[341]

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[337] *Nat'l Ass'n of Home Builders v. E.P.A.*, 682 F.3d 1032, 1040 (D.C. Cir. 2012).

[338] *See, e.g., Business Roundtable v. SEC,* 647 F.3d 1144 (D.C.Cir.2011); *Sec. Indus. & Fin. Markets Ass'n v. United States Commodity Futures Trading Comm'n*, 67 F. Supp. 3d 373 (D.D.C. 2014) (rejecting SEC rule that ignored costs of extraterritorial applications of its rule); *Pub. Citizen v. v. Fed. Motor Carrier Safety Admin.,* 374 F.3d 1209, 1216 (D.C. Cir. 2004) (when statute required agency setting limits on hours of driving for commercial truck drivers to consider rule's impacts on drivers' health, rejecting rulemaking that did not incorporate this factor into cost-benefit analysis).

[339] *Business Roundtable v. SEC*, 647 F.3d 1144 (D.C.Cir.2011).

[340] *Id*. at 1146 (citing Section 3(f) of the Exchange Act and Section 2(c) of the Investment Company Act of 1940, codified at 15 U.S.C. §§ 78c(f) and 80a–2(c)).

[341] *Id*. at 1148 (citing *Chamber of Commerce v. SEC*, 412 F.3d 133, 143 (D.C.Cir.2005).

The SEC promulgated a rule requiring public companies to provide shareholders with information about shareholder-nominated candidates for boards of directors. In promulgating the rule, the SEC stated that the rule would promote the "efficiency of the economy on the whole," and that its benefits would "justify [its] costs." The SEC ignored several costs associated with the proposed rule, including the costs of solicitation and campaigning that companies would incur to oppose shareholder-nominated candidates, the costs that the use of the rule by shareholders with special interests would impose upon companies, and the effect the final rule would have upon the total number of board election contests.

Industry had submitted comments on the rule predicting that these factors would cause it to incur substantial expenditures that were not accounted for in the cost-benefit analysis. The court struck down the rule on the grounds that the SEC had "failed adequately to quantify the certain costs or to explain why those costs could not be quantified."[342] The court further found that because the agency had failed to consider critical cost data, the agency "had no way of knowing" whether the rule would ultimately be a net benefit.[343] The court thus rejected the rule because the agency had acted arbitrarily "[b]y ducking serious evaluation of the costs that could be imposed."[344]

Uncertainty about the magnitude of a given cost or benefit is not grounds for ignoring that cost or benefit. An agency's cost-benefit analysis must evaluate the significant costs and benefits of a rule, even when there is a lack of reliable data or substantial uncertainty as to a rule's costs or benefits. In *Pub. Citizen v. v. Fed. Motor Carrier Safety Admin.*, the D.C. Circuit rejected a rule modifying the consecutive hours during which long-haul truck drivers could operate commercial vehicles.[345] In that case, the agency was statutorily-required to evaluate in the impact of its rule on driver health. In the model the agency used to forecast the rule's costs and benefits, however, the agency did not attempt to quantify the effects of increased time driving on driver risk.[346] The agency justified this omission by stating that it "it did not have sufficient data on the magnitude of such effects."[347] The court rejected this explanation, stating, "[t]he mere fact that the magnitude of time-on-task effects is *uncertain* is no justification for *disregarding* the effect entirely."[348] Courts have stated in several other instances that an agency

[342] *Id*. at 1148-49.

[343] *Id*.

[344] *Id*. at 1152.

[345] 374 F.3d 1209 (D.C. Cir. 2004).

[346] *Id*. at 1218-19.

[347] *Id*. at 1218.

[348] *Id*. at 1219 (emphasis in original).

is required to consider relevant costs and benefits even when reliable predictive data does not exist.[349]

2. An Agency's Cost-Benefit Analysis May Not Derive Estimated Costs and Benefits Based on Assumptions that Are Irrational or Lack Support in the Record.

While an agency must estimate relevant costs and benefits even if it lacks fully reliable data on which to make such estimates, the agency may not base estimates on assumptions that lack support in the record and cause errors in the cost-benefit analysis.[350] In *Gas Appliance Mfrs. Ass'n v. Dep't of Energy*, the court rejected a Department of Energy ("DOE") rulemaking setting rules for heat losses from certain electric water heaters.[351] The rule was issued under the New Buildings Act,[352] which required that DOE assure that its standards "are adequately analyzed in terms of," among other things, "economic cost and benefit, and impact upon affected groups."[353] Based on the requirement that the agency balance costs and benefits, the court stated that it was required to show a "discernable path to compliance," meaning, how industry would meet the new standards at manageable costs.[354] The court found arbitrary and capricious DOE's assumption that its rule would lead to a 40% reduction in certain heat losses, because DOE had not specified what steps industry would need to take to achieve these reductions and the costs of those steps.[355] The court explained that "some method of compliance must be proposed in order to provide a legitimate foundation for the cost-benefit analysis."[356]

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[349] *See Center for Biological Diversity v. NHTSB*, 538 F.3d 1172, 1198-1203 (9th Cir. 2008) (rejecting rule setting corporate average fuel economy standards for light trucks when agency failed to monetize benefits of greenhouse gas reductions in its cost-benefit analysis, even though there was an "extremely wide variation in published estimates of damage costs from greenhouse gas emissions."); *Chamber of Commerce of U.S. v. Sec. & Exch. Comm'n*, 412 F.3d 133, 143 (D.C. Cir. 2005) (agency's lacking of reliable basis on which to estimate costs of a rule, and resulting ability to determine only a range within the rule's costs would fall, "does not excuse the [agency] from its statutory obligation to determine as best it can the economic implications of the rule it has proposed."); *Sec. Indus. & Fin. Markets Ass'n v. United States Commodity Futures Trading Comm'n*, 67 F. Supp. 3d 373, 432 (D.D.C. 2014) (even in the absence of reliable data on an important cost factor, an agency has "a duty to consider 'as best it could the economic implications of the rules.'").

[350] *Gas Appliance Mfrs. Ass'n*, 998 F.2d 1041, 1050 (D.C. Cir. 1993).

[351] 998 F.2d 1041 (D.C. Cir. 1993).

[352] 42 U.S.C. §§ 6831–40 (1988).

[353] 998 F.2d at 1043 (citing 42 U.S.C. § 6839).

[354] *Id*. at 1045.

[355] *Id*. at 1047.

[356] *Id*. at 1047.

The court also rejected DOE's rulemaking on the grounds that the inputs DOE used to project its costs lacked support in the record. DOE assumed that the relative costs of imposing requirements for adding insulation to water heaters would be comparable for residential and commercial heaters.[357] Industry questioned this assumption, asserting that these costs would be far greater for commercial heaters than residential heaters. DOE could not identify anything in the record supporting its assumption, and the court found that DOE had failed to exercise reasoned decisionmaking, in violation of the APA.[358] Courts have in several other instances struck down rulemakings in which flawed assumptions affected the outcome of the agency's cost-benefit analysis.[359]

E. PHMSA's Errors Accounting for Costs and Benefits of the Proposed Rule Violate the Pipeline Safety Act and Administrative Procedure Act.

The PRIA ignores billions of dollars of costs the proposed rule would impose on the pipeline industry. This violates the PSA and is arbitrary and capricious under the APA. While the PRIA estimates the standards' proposed costs as between \$39.8 million and \$47.4 million and its benefits as between \$215.6 million and \$310.8 million, INGAA estimates that the standards' costs will far outweigh their benefits. Specifically, as summarized in Table C and fully described in Attachment 6, INGAA forecasts that the rule will impose costs of at least \$2.7 billion annually. These costs far outweigh PHMSA's estimated benefits, and PHMSA has overestimated the benefits as well. As such, the standards' benefits do not justify their costs.

The PRIA's underestimation of the rule's costs is caused in large part by its disregard of several costs of its proposed rule. The PRIA ignores, among other things:

- That most operators will utilize hydrotests to comply with MAOP reconfirmation requirements proposed under § 192.624, because of the high costs of its proposed restrictions on the use of ILI and ECA;
- That the costs of hydrostatically pressure testing short segments of pipe are substantially greater than longer sections on a per mile basis, and that the majority of pipe that will be pressure tested under its proposed requirements will be less than 0.25 miles in length;
- That the integrity management program process clarifications proposed under §§ 192.917 and 192.317 will require operators to develop systems to integrate new data elements at substantial costs;

[357] *Id*.

[358] *Id*. at 1047-48.

[359] *See, e.g, Advocates for Highway & Auto Safety v. FMCSA*, 429 F.3d 1136, 1146 (D.C. Cir. 2005) (rejecting rulemaking where FMCSA made "patently illogical" assumptions to support its conclusion that rule's benefits would justify its costs).

- That testing a single 200-foot segment would require the operator to blow down the full valve section of that pipe, and that by evaluating emissions of blowdowns on a per-mile basis, the PRIA inevitably underestimates the quantity of methane released by any tests on segments that are shorter than one mile in length;
- Costs of excavation and required coating repairs in its estimate of costs of complying with proposed external corrosion coatings requirements; and
- Costs the proposed rules will cause operators to incur under FERC regulations, such as demand charge credits.

By ignoring these implications of its proposed standards, the PRIA has substantially underestimated costs. The PRIA's failure to account for these costs, and to show that the standards' benefits justify the costs, violates the plain language of the PSA. The PSA requires that PHMSA "reasonably identifiable or estimated" benefits and costs expected to result from implementation or compliance with each of its proposed standards,[360] and PHMSA may not propose a standard without making a "reasoned determination that the benefits of the intended standard justify its costs."[361] PHMSA clearly has failed this requirement, as it has not reasonably identified, or even attempted to estimate, several of the massive costs its proposed rules would impose upon the pipeline industry. The costs of the proposed standards, if reasonably accounted for, do not justify their benefits. As such, the PRIA violates the PSA.

The PRIA's ignoring of costs is also arbitrary and capricious under the APA because its conclusion that the standards' costs justify their benefits is based on a gross underestimation of the standards' costs. PHMSA's disregard of these costs is similar to the errors that led the D.C. Circuit to reject the SEC's rulemaking in *Business Roundtable*, where the agency failed to accurately estimate the costs of its proposed rules, and thus could not show that its rules yielded a net benefit.[362] Even PHMSA's inability to precisely quantify certain of these costs would not excuse its wholesale failure to consider them.[363] Because a reasonable cost-benefit analysis of the rule would show that the costs of the proposed standards do not justify their benefits, PHMSA's rulemaking is arbitrary and capricious.

PHMSA's reliance on incorrect and unsupported assumptions to carry out its cost-benefit analysis is also arbitrary and capricious. These errors are similar to those that the D.C. Circuit rejected in *Gas Appliance Mfrs. Ass'n v. Dep't of Energy*, where the court found that the DOE had estimated costs using assumptions that lacked support in the record and contradicted

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[360] 49 U.S.C.A. § 60102(b)(2)(D-E).

[361] *Id*. at § 60102(b)(5).

[362] *Business Roundtable*, 647 F3d 1144, 1153 (D.C. Cir. 2011).

[363] *Pub. Citizen v. v. Fed. Motor Carrier Safety Admin*, 374 F.3d 1209, 1219 (D.C. Cir. 2004).

industry-backed data.[364] Here, PHMSA assumes, for instance, that costs of hydrostatic pressure testing steadily increase as pipeline segments get shorter, but arbitrarily declines to consider that these costs continue increasing for pipeline segments less than a mile in length.[365] PHMSA provides no support for this assumption, and the assumption causes the agency to drastically underestimate the costs of pressure testing. As a result, PHMSA estimates the costs of its proposed pressure testing requirements at $17 million, compared with INGAA's estimate of $808 million. PHMSA also assumes without justification that operators will experience only four MOC events per year, while estimates based on operator data support that pipelines will most likely experience at a minimum of 297,790 MOC events per year. These unreasonable and unsupported assumptions have caused PHMSA to substantially underestimate the costs of its proposed standards.

The errors in the PRIA cause the rulemaking to violate with the requirements of the PSA and APA. PHMSA must conduct a new cost-benefit analysis that reasonably estimates the costs and benefits of its proposed standards.

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[364] *Gas Appliance Mfrs. Ass'n*, 998 F.2d 1041, 1050 (D.C. Cir. 1993).

[365] *See* PRIA at 57.

XVII. PHMSA's Draft Environmental Assessment Does Not Comply with CEQ Guidelines and NEPA

A. Overview of NEPA Compliance

NEPA requires that before issuing a final rule adopting the proposed safety standards, PHMSA must assess whether the proposal constitutes a major federal action that will significantly affect the quality of the human environment.[366] NEPA's mandate serves the twin purposes of ensuring that (1) agency decisions include informed and careful consideration of environmental impacts, and (2) agencies inform the public of that impact and enable interested persons to participate in the decision-making process and the implementation of that decision.[367] If the proposed rule will have a "significant impact," PHMSA must prepare an environmental impact statement (EIS), which provides a detailed and comprehensive analysis of the potential environmental impacts of the proposed action and must include an analysis of alternatives to the proposed action.[368] PHMSA can prepare an environmental assessment, which "[b]riefly provides sufficient evidence and analysis for determining whether" the proposed action warrants an EIS.[369] If, based upon the environmental assessment, PHMSA determines that the proposed action does not significantly affect the environment, it will issue a finding of no significant impact explaining its reasoning; otherwise, an EIS is required.[370]

1. The Purpose and Need Statement Is Inconsistent with Statutory Directives

NEPA requires federal agencies proposing actions to "briefly specify the underlying purpose and need to which the agency is responding in proposing the alternatives including the proposed action."[371] In defining a purpose and need statement, an action agency must place particular weight on the relevant statutes and other authorities that define its legal duties and responsibilities in relation to the proposed project or program.[372] While an agency has discretion with respect to its definition of the purpose and objective of a proposed action, the agency may not "define the objectives [of a proposed action] so narrowly as to preclude a

[366] 42 U.S.C. § 4332(2)

[367] *Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 768 (2004).

[368] 42 U.S.C. §§ 4332(2)(C) & (E).

[369] 40 C.F.R. § 1508.9. It is not necessary to prepare an EA if the agency decides to proceed directly to preparing an EIS. 40 C.F.R. § 1501.3(a).

[370] 40 C.F.R. §§ 1501.4, 1508.13.

[371] 40 C.F.R. §§ 1502.13, 1508(9)(b).

[372] *Citizens Against Burlington v. Busey*, 938 F.2d 190, 196 (D.C. Cir. 1991) ("[A]n agency should always consider the views of Congress, expressed, to the extent that the agency can determine them, in the agency's statutory authorization to act, as well as in other congressional directives.").

reasonable consideration of alternatives."[373] Delineating the appropriate scope of the purpose and need statement is important because it will dictate the alternatives and scope of environmental effects analysis that PHMSA must consider in the EA.[374]

PHMSA states that "[t]he purpose of the proposed rule is to significantly increase the safe operation of gas pipelines."[375] PHMSA also indicates that many of the proposals in the NPRM respond to statutory mandates in the 2011 Act and recommendations from the NTSB and Government Accountability Office.[376] PHMSA's articulation of the purpose and need of the NPRM fails to incorporate other mandates of the PSA. While any standard must be designed to meet the need for gas pipeline safety, PHMSA is also required by statute to ensure that the standard is "practicable" and designed to "protect[] the environment."[377] Consideration of these additional statutory requirements is necessary because, like the focus on pipeline safety, they dictate the scope of measures that PHMSA can propose and promulgate. Furthermore, in the NEPA context, the failure to include practicability as part of the purpose and need of the action affects the adequacy of the alternatives considered and resulting analysis of effects on the human environment.[378] PHMSA must revise the purpose and need of the proposed action to accurately reflect Congressional directives.

2. The Range of Alternatives Considered is Unreasonably Narrow

Using the purpose and need statement as a foundation, federal agencies are directed under NEPA to "study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources. . . ."[379] The discussion of alternatives is "the heart" of the NEPA process, and is intended to provide a "clear basis for choice among options by the decisionmaker and the public."[380] PHMSA is required to "[r]igorously explore and objectively evaluate all reasonable alternatives."[381] While the courts have not specified an explicit numerical requirement when

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373 *Wyo. v. U.S. Dept. of Agric.*, 661 F.3d 1209, 1244 (10th Cir. 2011) (citing *Citizens' Comm. to Save Our Canyons v. U.S. Forest Serv.*, 297 F.3d 1012, 1030 (2002).

374 *Theodore Roosevelt Conservation P'ship v. Salazar*, 661 F.3d 66, 72 (D.C. Cir. 2011).

375 PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 4 (Mar. 21, 2016) (Draft EA).

376 PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 4 (Mar. 21, 2016) (Draft EA).

377 49 U.S.C. § 60102(b)(1).

378 *Theodore Roosevelt Conservation P'ship v. Salazaar*, 661 F.3d 66, 72-73 (D.C. Cir. 2011) ("it is the . . . purpose and need for action that will determine the range of alternatives and provide a basis for the selection of an alternative in a decision").

379 42 U.S.C. § 4332(2)(E).

380 40 C.F.R. § 1502.14.

381 40 C.F.R. § 1502.14(a); *Nat'l Parks Conservation Ass'n v. U. S. Forest Serv.*, 2016 WL 1273190 *9 (D.D.C. Mar. 31, 2016) (noting that obligation to evaluate all reasonable alternatives applies to preparation of EIS or EA)

assessing the reasonableness of the alternatives considered, PHMSA must consider a range of alternatives that are "representative of the spectrum of available methods."[382] PHMSA can only exclude alternatives from consideration when it determines that the alternative does not achieve the stated objective of the proposed rule.[383]

PHMSA's alternatives analysis is flawed because it is too limited in scope. An agency's alternatives analysis should be a function of the "purpose and need" of the action under review.[384] PHMSA broadly states that the purpose of the proposed rule is "to significantly increase the safe operation of gas pipelines."[385] Despite this broad objective, PHMSA only identifies one alternative, in addition to the no action alternative, for consideration in its NEPA analysis.[386] In doing so, PHMSA improperly assumes that the suite of amendments and editorial changes included in its proposed action alternative are the only measures that will achieve the stated purpose of the proposed rule. Given the numerous components of the proposed action, it is readily apparent that there a variety of alternative actions that could meet the objective of the proposed rule by using different approaches while also reducing the impacts of the agency action. It is unreasonable, and contrary to the purpose of NEPA, for PHMSA to only put forth one alternative for consideration and analysis given the broad spectrum of other methods that may be available.

(quoting 40 C.F.R. § 1502.14(a)); Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations, 46 Fed. Reg. 18,026, 18,027 (Mar.ch 23, 1981) ("In determining the scope of alternatives to be considered, the emphasis is on what is 'reasonable' rather than on whether the proponent or applicant likes or is itself capable of carrying out the particular alternative. Reasonable alternatives include those that are practical or feasible from a technical and economic standpoint and using common sense, rather than simply desirable from the standpoint of the applicant.").

[382] *Pub. Employees for Envtl. Responsibility v. U.S. Fish & Wildlife Serv.*, 2016 WL 1254214, at *5 (D.D.C. Mar. 29, 2016) (quoting *Biodiversity Conservation All. V U.S. Bureau of Land Mgmt.*, 404 F. Supp. 2d 2012, 2018 (D.D.C. 2005); *Am. Oceans Campaign v. Daley*, 183 F. Supp. 2d 1, 20 (D.D.C. 2000) (finding an EA insufficient, in part, based on failure to consider any alternatives beside the status quo and adoption of the proposed action); *but see Myersville Citizens for a Rural Comty., Inc. v. FERC*, 783 F.3d 1301, 1323 (D.C. Cir. 2015) (noting that "the consideration of alternatives in an [EA] need not be as rigorous as the consideration of alternatives in an [EIS]").

[383] *City of Alexandria v. Slater*, 198 F.3d 862, 867 (D.C.Cir.1999) ("[A]n alternative is properly excluded from consideration . . . only if it would be reasonable for the agency to conclude that the alternative does not bring about the ends of the federal action.").

[384] *See* 40 C.F.R. § 1502.13 (agency must "specify the underlying purpose and need to which the agency is responding in proposing the alternatives.").

[385] PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 4 (Mar. 21, 2016).

[386] INGAA notes that PHMSA considered and dismissed three types of alternatives for various topics in the proposed rule (extending compliance deadlines, partial and/or full implementation, and technical alternatives). PHMSA rejected these alternatives for a variety of reasons, including impacts on safety improvement, increased compliance costs, and inconsistency with statutory mandates. PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment at 11-13, Docket No. PHMSA-2011-0023 (Mar. 21, 2016).

PHMSA is required include other alternatives to the proposed action in order to present a reasonable range of options for consideration.

3. Analysis of Environmental Effects

NEPA requires federal agencies to "take a 'hard look' at the environmental consequences" of their proposed actions before deciding whether and how to proceed.[387] The courts have explained that the "hard look" requirement is satisfied if "'the statement contains sufficient discussion of the relevant issues and opposing viewpoints,' and . . . the agency's decision is 'fully informed' and 'well-considered.'"[388] In order to determine whether a federal action is significant, an EA must consider all of the environmental effects that are required to be considered under NEPA.[389] The effects analysis includes consideration of: (1) direct effects; (2) indirect effects; and (3) cumulative effects.[390]

B. The Analysis of Direct Effects is Impermissibly Vague and Superficial

Direct effects are defined as those that are "caused by the action and occur at the same time and place"[391] The scope of effects that must be considered are defined broadly to include ecological, aesthetic, historic, cultural, economic, social, or health effects, and may also include those resulting from actions which have both beneficial and detrimental effects.[392] In determining whether a proposed action may significantly affect the environment, NEPA requires that both the context and intensity of that action be considered.[393] In considering context, PHMSA is required to analyze the significance of the action "in several contexts such as society as a whole (human, national), the affected region, the affected interests, and the locality."[394] Furthermore, PHMSA's consideration of intensity must evaluate ten factors, including: "[t]he degree to which the proposed action affects public health or safety;" "[u]nique characteristics of the geographic area such as proximity to historic or cultural resources, park lands, prime farmlands, wetlands, wild and scenic rivers, or ecologically critical areas;" and "the

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[387] *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 350-51 (1989) (citing *Kleppe v. Sierra Club*, 427 U.S. 390, 410, n.21 (1976).

[388] *Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d 1301, 1324-25 (D.C. Cir. 2015) (quoting *Nevada v. Dep't of Energy*, 457 F.3d 78, 93 (D.C. Cir. 2006)).

[389] 40 C.F.R. § 1508.9(b) (EA "[s]hall include brief discussions . . . of the environmental impacts of the proposed action and alternatives").

[390] *E.g., Nat'l Parks Conservation Ass'n v. U.S. Forest Serv.*, 2016 WL 1273190, *14 (D.D.C. Mar. 31, 2016).

[391] 40 C.F.R. § 1508.8(a).

[392] 40 C.F.R. § 1508.8.

[393] 40 C.F.R. § 1508.27.

[394] *Id.* § 1508.27 (a).

degree to which the action may adversely affect an endangered or threatened species or [critical habitat] under the Endangered Species Act."[395]

PHMSA's EA provides only a superficial consideration of environmental consequences and fails to provide the requisite "hard look" under NEPA. Courts have found that EAs are insufficient when:

> there is simply not enough evidence or analysis in any EA to determine whether an EIS is necessary; all the EAs are couched in very general and vague terms, and spend more time <u>describing</u> the proposed alternative and the requirements of NEPA than they do actually <u>analyzing</u> the proposed alternative and complying with the requirements of NEPA.[396]

PHMSA's EA suffers from these deficiencies. The proposed rule would apply to gas pipelines nationwide and could affect a variety of different geographic areas all with different environmental characteristics, ecological significance, species compositions, and other attributes. Notwithstanding this breadth of application, PHMSA's analysis of the effects of the proposed rule is minimal at best and, even then, is limited to general and vague terms.[397]

The EA acknowledges that the proposed rule could affect the physical environment by requiring preventative maintenance activities that, in turn, lead to more excavations that result in ground disturbance.[398] The EA also acknowledges that this ground disturbance could:

- Cause sedimentation into wetlands and waterways that could reduce water quality and diminish aquatic habitat;
- Disturb vegetation that could reduce available wildlife habitat for terrestrial species; and
- Disturb historical and archaeological resources and farmland, if any of these resources are present.[399]

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[395] *Id.* § 1508.27(b).

[396] *Am. Oceans Campaign v. Daley*, 183 F. Supp. 2d 1, 20 (D.D.C. 2000) (noting that there was no "substantive discussion of how fishing practices and gear may damage corals, disrupt fish habitat, and destroy benthic life . . ."); *Blue Mountains Biodiversity Project v. Blackwood*, 161 F.3d 1208, 1213 (9th Cir. 1998) (warning that "general statements about 'possible' effects and 'some risk' do not constitute a 'hard look' absent a justification regarding why more definitive information could not be provided.") (quoting *Neighbors of Cuddy Mountain v. U.S. Forest Serv.*, 137 F.3d 1372, 1380 (9th Cir. 1998).

[397] *See* PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 14-18 (Mar. 21, 2016) (Draft EA). Contrary to the approach taken in the EA, PHMSA is required to "[i]dentify environment effects and values in adequate detail so they can be compared to economic and technical analyses." 40 C.F.R. § 1501.2(b).

[398] PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 14 (Mar. 21, 2016).

[399] PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 14 (Mar. 21, 2016).

Based on this assessment, PHMSA concludes that these effects would be negligible because the impacts are expected to be localized within the existing right-of-way, temporary in duration, and decrease the likelihood of catastrophic damage due to pipeline failure.[400] PHMSA's EA also addresses environmental justice concerns, greenhouse gas emissions, public safety, and public health in a similarly perfunctory fashion.[401]

Because PHMSA's EA provides only general statements about possible effects without actually analyzing the proposed alternative, it does not comply with the "hard look" standard. For example, the EA notes that there could be impacts to wetlands, rivers, historic resources, and farmland.[402] While PHMSA is required to consider these types of resources as part of its consideration of intensity of the action,[403] the EA merely identifies the specified characteristic and provides a conclusory statement regarding the magnitude of impact without any detail, supporting analysis or evaluation.[404] This approach precludes any ability to determine the significance of the action because there is a dearth of information upon which to base such a conclusion.[405]

C. Consideration of Indirect Effects

In addition to direct effects, the EA must also consider indirect effects of the action. Indirect effects are defined as those "which are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable."[406] These effects may include

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[400] PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 14-15 (Mar. 21, 2016).

[401] PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 15-18 (Mar. 21, 2016). INGAA notes that in two instances PHMSA attempts to provide actual data—estimating the potential reduction of greenhouse gas emissions and the reduction of fatalities. PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 15-16 (Mar. 21, 2016). Given the perfunctory treatment of these analyses, it is unclear what factors PHMSA considered in quantifying these effects and whether the scope of these analyses fully contemplated all components of the proposed rule.

[402] While Draft EA also identifies potential impacts to terrestrial species, there is no discussion of species or crucial habitat under the Endangered Species Act.

[403] 40 C.F.R. § 1508.27(b)(3).

[404] If PHMSA lacks the data to properly consider these effects, its failure to properly acknowledge and address the many gaps in its environmental risk analysis is in itself a NEPA violation. PHMSA is required to "always make clear" when there is "incomplete and unavailable information." 40 C.F.R. § 1502.22; *Lands Council v. Powell,* 395 F.3d 1019, 1033 (9th Cir. 2005) (NEPA "requires up-front disclosures of relevant shortcomings in the data or models.").

[405] *Sierra Club v. Mainella*, 459 F. Supp. 2d 76, 108 (D.D.C. 2006) (Agency's failure to take a "hard look" was evidenced by the "lack of explanations supporting its conclusions and, in particular, its methodology of describing impacts using conclusory labels and then setting forth a bare conclusion without explanation as to the significance of an impact.").

[406] 40 C.F.R. § 1508.8(b); *Barnes v. U.S. Dep't of Transp.*, 655 F.3d 1124, 1136 (9th Cir. 2011) ("While 'foreseeing the unforeseeable' is not required, an agency must use its best efforts to find out all that it reasonably can.")

"growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effects on air and water and other natural systems, including ecosystems."[407]

The EA is deficient because it fails to include any discussion of indirect effects associated with the proposed action.

D. Failure to Consider Cumulative Effects

PHMSA is required to consider the cumulative effects of the proposed action. Cumulative effects are defined as "the impact on the environment which results from the incremental impacts of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (federal or non-federal) or person undertakes such other actions. Cumulative impacts "can result from individually minor but collectively significant actions taking place over a period of time."[408] Courts have consistently held that NEPA's cumulative effects requirements apply to EAs as well as EISs.[409] The D.C. Circuit has explained that:

> a meaningful cumulative impact analysis must identify (1) the area in which the effects of the proposed project will be felt; (2) the impacts that are expected in that area from the proposed project; (3) other actions—past, present, and proposed, and reasonably foreseeable—that have had or are expected to have impacts in the same area; (4) the impacts or expected impacts from these other actions; and (5) the overall impact that can be expected if the individual impacts are allowed to accumulate.[410]

PHMSA's EA does not include a cumulative effects analysis nor does it attempt to provide any insight into the past, present, and reasonably foreseeable actions that would help portray a "realistic evaluation of the total impacts" of the proposed action. On the contrary, when evaluating the various elements of the preferred alternative that could lead to more excavations, PHMSA repeatedly states that each proposed component would "individually have

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(citation omitted).

[407] 40 C.F.R. § 1508.8(b).

[408] 40 C.F.R. § 1508.7.

[409] *See Kern v. U.S. Bureau of Land Mgmt.*, 284 F.3d 1062, 1076 (9th Cir. 2002) ("[A]n EA may be deficient if it fails to include a cumulative impact analysis or to tier to an EIS that has conducted such an analysis."); *Grand Canyon Trust v. FAA*, 290 F.3d 339, 342 (D.C. Cir. 2002) (as amended) ("the consistent position in the case law is that, depending on the environmental concern at issue, the agency's EA must give a realistic evaluation of the total impacts and cannot isolate a proposed project, viewing it in a vacuum.").

[410] *Del. Riverkeeper Network v. FERC*, 753 F.3d 1304, 1319 (D.C. Cir. 2014) (quoting *Grand Canyon Trust v. FAA*, 290 F.3d 339, 345 (D.C. Cir. 2002)

minor localized environmental impacts."[411] By explicitly stating that it only considered effects "individually" and in a "localized" area, PHMSA has failed to conduct the requisite cumulative effects analysis. Instead, PHMSA violated NEPA by only considering these effects of its preferred alternative in a vacuum. Before promulgating any final rule, PHMSA must assess the totality of impacts from both its proposed action and those other actions that are reasonably foreseeable.

E. The Consideration of Climate Change is Deficient

Courts have found that an agency has a duty to assess "the effects of *its* actions on global warming within the context of other actions that also affect global warming."[412] Based upon guidance from the Council on Environmental Quality, PHMSA "should consider the following . . . : (1) the potential effects of a proposed action on climate change as indicated by its GHG emissions; and (2) the implications of climate change for the environmental effects of a proposed action."[413]

While PHMSA notes that the proposed rule may result in fewer accidents or incidents which could reduce the emission of GHGs,[414] the EA fails to consider that the proposed rule will also cause an increase in GHG emissions.

[411] PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 15-18 (Mar. 21, 2016) (in some places, PMSA states that the excavations would "individually have very minor and localized environmental impacts").

[412] *Ctr. for Biological Diversity v. Nat'l Hwy. Traffic Safety Admin.*, 538 F.3d 1172, 1217 (9th Cir. 2008) (requiring agency to examine effects associated with greenhouse gas emissions resulting from the promulgation of corporate average fuel economy standards for light trucks).

[413] Revised Draft Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in NEPA Reviews, 79 Fed. Reg. 77,802, 77,824 (Dec. 24, 2014).

[414] PHMSA, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Draft Environmental Assessment, Docket No. PHMSA-2011-0023 at 15 (Mar. 21, 2016).