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Docket # PHMSA-2011-0023

COMMENTS of the AMERICAN PETROLEUM INSTITUTE
on
NOTICE OF PROPOSED RULEMAKING:

“Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines”

By the Pipeline and Hazardous Materials Safety Administration
U.S. DEPARTMENT OF TRANSPORTATION
81 Fed. Reg. 20,722 (April 8, 2016)

Comments Submitted on July 7, 2016



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The American Petroleum Institute (API)¹ appreciates the opportunity to submit comments in response to the Notice of Proposed Rulemaking (NPRM) issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA or Agency) on April 8, 2016, in the above-referenced proceeding. API members are dedicated to a risk-based approach to pipeline safety—one that strives for continuous improvement through addressing known, quantifiable issues. Significantly, that is the same approach that Congress has used over the decades in its directives to the Department of Transportation (DOT) and PHMSA for regulating pipeline safety. API acknowledges PHMSA for issuing this NPRM and responding to outstanding congressional mandates and National Transportation Safety Board (NTSB) and U.S. Government Accountability Office (GAO) recommendations.

The pipeline industry is committed to protecting the health and safety of its neighbors, workers, customers, and the communities through which natural gas and other gaseous materials are shipped. Pipeline operators work diligently to construct, operate, and maintain their facilities in a safe and reliable manner.

API values and appreciates the many aspects of PHMSA's rulemaking that are intended to improve pipeline safety and provide additional regulatory certainty for our members. Although API does not oppose certain aspects of the NPRM (*e.g.*, reporting of maximum allowable

¹ API is the national trade association representing all facets of the oil and natural gas industry, which supports 9.8 million U.S. jobs and 8 percent of the U.S. economy. API's more than 650 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 25 million Americans.

operating pressure (MAOP) exceedances for gas transmission lines and clarifying integrity management reassessment interval extensions), there are many areas of the proposed rule that require revision as addressed in more detail in the comments provided in the remainder of this letter.

API's key issues with respect to the NPRM include:

1. Gathering Lines

- Extending federal regulation to production flow lines, which are not transportation-related pipelines subject to PHMSA's jurisdiction by law;
- Modifying the regulatory framework for determining whether a pipeline qualifies as a gathering line without complying with congressional-mandates, obtaining adequate data, conducting an appropriate risk-based analysis, or providing any discernible benefits to the public or the environment;
- Requiring operators of unregulated gathering lines to comply with overly burdensome reporting requirements that are unnecessary and which exceed the scope of PHMSA's information collection authority;
- Regulating small-diameter rural gathering lines without regard to congressional mandates that required adequate data collection, appropriate risk-based analysis completion, and demonstrated increase to public safety or the environment; and
- Failing to recognize that there are significant differences in the construction of gathering and transmission lines, and that applying the same rules to both pipelines leads to severe, unintended consequences, such as indirectly prohibiting the use of non-metallic materials in gathering line construction, which are superior to steel materials in many applications.

2. Transmission Lines

- Proposing new rules for pipeline materials and maximum allowable operating pressure verification that are convoluted, overly burdensome, impractical, technically unsupported, and completely unworkable and which do not address the concerns that actually gave rise to the relevant congressional and NTSB recommendations;
- Establishing repair criteria that are too prescriptive, lack an adequate technical justification, and which do not reflect a risk-based approach; and
- Introducing unnecessarily prescriptive requirements into the integrity management regulations that fundamentally undermine the core risk-based philosophy of that program.

3. Other

- Continuing to rely on outdated or obsolete technical standards and practices;
- Proposing retroactive recordkeeping requirements that cannot be achieved and which are contrary to law;

- Grossly underestimating the costs and overestimating the benefits of the proposed rules (for instance, by failing to recognize that small gathering companies, which represent 62% of all gathering companies, would need to spend about 90% of their total annual revenue to comply with the NRPM).
- Providing inadequate time to afford stakeholders a meaningful opportunity to review, assess, and comment on the proposed rules.

In developing these comments, API believed it was important for industry to coordinate and voice concerns in unison where possible. API worked with organizations such as the American Gas Association (AGA), the Interstate Natural Gas Association of America (INGAA), the Gas Processors Association (GPA), the Independent Petroleum Association of America (IPAA), and the Plastic Pipes Institute (PPI). Industry was able to achieve consensus in many areas and further coordination would have been possible if additional time had been afforded by PHMSA. Throughout the development of these comments, API has shown its willingness to collaborate with other operators in the natural gas value chain. API and the aforementioned associations would welcome the chance to discuss “Fit for Purpose” regulations with PHMSA and other stakeholders in a similar collaborative fashion.

API respectfully requests that PHMSA carefully reconsider the proposed regulations and make the necessary revisions requested to ensure that they are consistent with the following basic principles: (1) address known, quantifiable risks that are demonstrated through data; (2) are justified by an accurate cost-benefit analysis that appropriately considers the impact on the industry and the corresponding safety benefits; (3) are operationally feasible in practice; (4) eliminate inconsistencies with existing regulations and other proposals; (5) maintain flexibility by allowing appropriate use of operators’ engineering judgment and experience; and (6) incorporate valuable advancements in the science and technology of pipeline integrity to allow operators to take advantage of, and public safety and the environment to benefit from, future research and development.

Finally, given the above, API has recommended suggested revisions to PHMSA’s proposal in redline format. We respectfully request that PHMSA issue a final rule consistent with the comments and recommendations below.

A handwritten signature in black ink, reading "Robin Rorick". The signature is written in a cursive, flowing style. The first name "Robin" is written with a large, stylized 'R' and the last name "Rorick" follows in a similar cursive script.

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I. Overview

API believes that the proposals in the NPRM are contrary to PHMSA's statutory directives and existing regulatory framework because the proposals are not driven by a risk management approach that is targeted toward eliminating the most significant risks posed to public safety and the environment. PHMSA significantly overstates the benefits and underestimates the cost and burden to industry that would be required to implement the expansive proposals. The proposed new rules set forth in the NPRM would nearly double the size of the gas pipeline safety regulations in 49 C.F.R. Part 192 and represent the most sweeping expansion of federal authority in the 48-year history of the program.

Taken together, the changes proposed in the NPRM are arbitrary, capricious, and contrary to the law. As drafted, the NPRM will almost inevitably lead to prolonged challenges because of the errors and inconsistencies in this expansive rulemaking. We encourage PHMSA to continue to work with the regulated community and the public after review of the comments received on the NPRM in order to address the many proposed changes that warrant further consideration or to withdraw those proposals that do not meet Constitutional, Congressional, or Administrative Procedure Act standards.

The proposals are also too expansive and would, in practice, affect many interrelating Part 192 regulations that the Agency fails to acknowledge in the NPRM. As drafted, many of the NPRM proposals are vague and subject to potentially varying interpretation. Numerous proposals are simply impossible or impracticable to implement. As such, PHMSA's cost-benefit analysis underestimates the cost this proposal will impose on industry and overestimates the benefits it will bring.

In addition, PHMSA would impose additional obligations where no demonstrated problem exists (*e.g.*, gas gathering and corrosion control) or go well beyond any demonstrated problem (*e.g.*, material documentation, MAOP verification, recordkeeping). Many of the Agency's proposals do not directly address congressional mandates and NTSB and GAO recommendations, instead they overreach in other areas without adequate justification. For example, the Agency's proposed overhaul of the gas gathering rules and assessment criteria outside of high consequence areas (HCAs) respectively rely upon PHMSA Gas Gathering and Class location reports, neither of which is complete or contain adequate analysis and the latter of which PHMSA released only weeks before the comment deadline.

The expansive gas gathering rules propose to completely redefine regulated gathering lines by abandoning established industry standards that the industry has relied on for over a decade and imposing burdensome material documentation, MAOP verification, and recordkeeping obligations. With respect to material documentation and MAOP verification, these concepts are not aligned with the approach outlined by Congress and recommended by the NTSB and therefore, should be withdrawn entirely or significantly revised. Further, the NPRM would apply material design and associated recordkeeping standards to existing pipelines that have been exempted from those requirements for pre-1970 transmission pipelines and pre-2007 onshore gathering pipelines.

As proposed, PHMSA's NPRM is vague, overbroad and without justification in many areas. As a result, it would be vulnerable to a legal challenge. API recommends that PHMSA consider holding public workshops after reviewing the submitted public comments, to improve transparency and address the outlined concerns.

A. PHMSA Grossly Underestimates the Costs and Overestimates the Benefits of the NPRM

The sheer scope and breadth of the new proposed rules points to a very significant associated cost. Many of these proposals would require extensive new tests or modifications of equipment. *See e.g., NPRM at 20838 (assessments outside of high consequence areas); 20838 (non-high consequence area repair criteria).* The Agency itself admits that taken together its proposal will require "full utilization or expansion of industry resources devoted to assessments" and that this rulemaking proposal constitutes a more costly effort in terms of assessments and industry resources than the original IM rules. *NPRM at 20733.*

Despite this acknowledgement, the proposal suggests that industry wide implementation costs would be surprisingly low, \$597 million, and greatly outweighed by an equally surprising high estimate of benefit, between roughly \$3.2 billion and \$3.7 billion. *PHMSA Preliminary Regulatory Impact Analysis (Preliminary RIA), p. 117, Table 3-106, p. 122, Table 4-26, p. 127, Table 4-15* (original figures converted from annual to lump sum). Due to PHMSA's inaccurate cost estimate and the massive nature of the proposal, API contracted with ICF International (ICF) to evaluate the cost impact and the benefits of the NPRM, as outlined in the PHMSA's Preliminary RIA. ICF found (1) numerous costs that PHMSA failed to account for in its Preliminary RIA, (2) costs that were estimated incorrectly by PHMSA, and (3) benefits that were overestimated. When these items are properly accounted for, the total cost of the proposed rule increases by more than 50 times from \$597.0 million to \$33.4 billion and benefits decrease from a midpoint estimate of \$3.5 billion to \$437.0 million (all numbers are net present value over 15 years at 7% discount rate).

Lastly, this is not an exhaustive accounting of all of the potential cost increases. Due to the enormity of the regulatory changes proposed, many cost impacts were not identified in time to perform an exhaustive accounting analysis. A more detailed summary of ICF's analysis, including some of these impacts, is set forth in ICF's report, *Cost and Benefit Impact Analysis of PHMSA Natural Gas Gathering and Transmission Regulation Proposal (Jul.1, 2016)*, which is filed in the rulemaking docket.

1. Summary of ICF Cost Benefit Analysis

Revised Calculations: Summary of 15 Year Net Present Value Benefits and Costs for Transmission and Gathering Lines (Millions; 2015\$)							
Topic Area		7% Discount Rate for Revised Calculations			7% Discount Rate for PHMSA Preliminary RIA ¹		
		Benefits -Low	Benefits -High	Costs	Benefits -Low	Benefits -High	Costs
1	Re-establish MAOP, Verify Material Properties, and Integrity Assessment Outside HCAs	\$138.7	\$401.0	\$772.3	\$2,953.5	\$3,457.5	\$267.0
2	Field Repair of Damages - (More Timely Repairs)	n.e.	n.e.	\$3,578.2	n.e.	n.e.	\$33.0
3	Management of Change Process Improvement	\$16.4	\$16.4	\$12.3	\$16.5	\$16.5	\$10.5
4	Corrosion Control	\$96.1	\$96.1	\$114.6	\$82.5	\$82.5	\$94.5
5	Pipeline Inspection Following Extreme Events	\$4.7	\$4.7	\$63.2	\$4.5	\$4.5	\$1.5
6	MAOP Exceedance Reports and Records Verification	n.e.	n.e.	\$2.9	n.e.	n.e.	\$3.0
7	Launcher/Receiver Pressure Relief	\$6.7	\$6.7	\$0.4	\$6.0	\$6.0	\$0.0
8	Expansion of Gathering Regulation	\$43.3	\$43.3	\$28,872.2	\$169.5	\$169.5	\$189.0
Total		\$305.9	\$568.2	\$33,416.1	\$3,234.0	\$3,738.0	\$597.0
n.e. = not estimated							
1. PHMSA Preliminary RIA values displayed are the average annual values in Table ES-6 of the RIA multiplied by 15 to get the 15 year value. This may be slightly off due to rounding in Table ES-6.							

2. Social Costs of Greenhouse Emissions

In order to determine the full benefits of the proposed rule, PHMSA uses both the Social Cost of Carbon (SCC) and the Social Cost of Methane (SC-CH₄), as developed by EPA, to monetize any carbon dioxide or methane emissions caused or reduced by the proposed rule. Though both social cost estimates have been used to calculate benefits of various rules across agencies, their application by PHMSA to the proposed rule is flawed generally and specifically. API has addressed the general flaws in estimates of the SCC and the SC-CH₄ before and includes them in an Appendix. Addressed here is PHMSA's specific inappropriate application of the SC-CH₄.

The Agency's Preliminary RIA uses a paper by Marten *et al.* (2014), to monetize the greenhouse gas (GHG) emission benefits associated with reduced methane emissions as well as costs associated with increased emissions. The SC-CH₄ is currently estimated by Marten *et al.* using a 5% and 3% discount rate. In the Preliminary RIA, PHMSA elected to use the SC-CH₄ estimate at the 3% discount rate. While this is an appropriate discount rate to use in comparison to other calculations that have been discounted at a 3% rate, PHMSA failed to use a higher discount rate in the SCC and SC-CH₄ estimates when the costs and benefits were evaluated at a 7% discount rate. Economic literature, as well as government guidelines, dictates that costs and benefits should be discounted at the same rate when a discount rate is applied. PHMSA failed to follow this standard practice when evaluating the costs and benefits of the rule at a 7% discount rate. In doing so, the Preliminary RIA applies inconsistent discount rates to GHG costs and benefits

versus other costs and benefits making comparisons between them difficult.

The choice of discount rate is material. For any given year, Marten *et al.*'s SC-CH₄ estimate discounted at 5% are approximately half the value of the same estimate discounted at 3%. Using the appropriate 7% discount rate would have changed the estimate by an even greater amount. Given that Marten *et al.* did not provide a 7% discount rate is further proof that the SC-CH₄ estimates are not appropriate for policy use at this time.

3. PHMSA Overestimates the Benefits of MAOP Verification

The NPRM states that “[t]he majority of benefits reflect cost savings from material verification (processes to determine maximum allowable operating pressure for segments for which records are inadequate) under the proposed rule compared to existing regulations . . .” *NPRM at 20723-20724*. Specifically, the proposal estimates that these cost savings account for approximately 82% of the benefits in the 7% discount scenario (\$2.67 billion over 15 years) and 83% of the benefits in the 3% discount scenario (\$3.67 billion over 15 years). *Id. at 20724, 20814*. In reaching these conclusions, PHMSA assumes that the yield strength requirements for steel pipe in 49 C.F.R. §192.107(b) and provisions for steel pipe of unknown or unlisted specification in Section II, D of Appendix B apply to any pipeline that lacks sufficient documentation for the operator to substantiate its MAOP under the new undefined “reliable, traceable, verifiable, and complete” standard. *NPRM at 20814*.²

By applying §192.107(b) and Appendix B, Section II, D to gas pipeline facilities after installation, PHMSA grossly overestimates (by nearly two orders of magnitude) the costs of complying with the current regulations and makes the anticipated benefits of the proposed pipeline materials and MAOP verification rules appear far more justified than they are in reality. Contrary to PHMSA's position, the tensile strength testing requirements in § 192.107(b) and Appendix B, Section II, D do not apply to all pipelines that lack sufficient documentation to substantiate MAOP under the new proposed undefined “reliable, traceable, verifiable, and complete” standard. *NPRM at 20828*. These testing requirements are part of PHMSA's design regulations, which by statute do not apply retroactively to gas pipeline facilities in existence before those regulations went into effect. 49 U.S.C. § 60104(b) (“a design, installation, construction, initial inspection, or initial testing standard does not apply to a pipeline facility existing when the standard is adopted”); 49 C.F.R. § 192.13(a). That includes any onshore gas pipeline (whether gathering, transmission, or distribution) readied for service prior to March 13, 1971, and any previously-exempt, regulated onshore gas gathering line readied for service prior March 15, 2007. *Id.*

Indeed, existing gas pipeline facilities are exempt from all of the design requirements in 49 C.F.R. Part 192, including the design pressure limitations in PHMSA's MAOP regulations, unless they are “replaced, relocated, or otherwise changed [.]” 49 C.F.R. §192.13(b). The

² Specifically, PHMSA states that: “Existing regulatory requirements [at §192.107(b)] related to bad or missing records would be more costly for operators to achieve compliance. Under existing regulations, in order for pipelines with insufficient records to maintain operating pressure, operators must excavate the pipeline at every 10 lengths of pipe (commonly referred to as joints) in accordance with section II-D of Appendix B of Part 192 [...], do a cutout, determine material properties by destructive tensile test, and repair the pipe. The process is similar to doing a repair via pipe replacement.” *NPRM at 20814*.

rulemaking history confirms that existing gas pipeline facilities are not subject to Part 192 design regulations, which include tensile strength testing requirements. *Final Rule, 35 Fed. Reg. 13248, 13250 (Aug. 19, 1970)* (“... [T]he prospective effect of Part 192 is made clear in §192.13. The [non-retroactivity provision in the] Natural Gas Pipeline Safety Act (Section 3(b)) speaks quite clearly on this point.”).

This has been reinforced by recent PHMSA enforcement and longstanding interpretive guidance. *See e.g., In the Matter of Belle Fourche Pipeline Co., Decision on Reconsideration, CPF No. 5-2004-5010 (Jul. 15, 2009)* (finding that design pressure limitations in Part 195 maximum operating pressure requirements do not apply to pipelines in existence prior to the effective date of those rules unless those facilities are replaced, relocated, or otherwise changed referring to “the long-standing statutory prohibition, currently codified at 49 U.S.C. §60104(b), on the retroactive application of design, construction, and initial testing standards to pipelines in existence when such standards are adopted.”); *Materials Transportation Bureau Interpretation, Operating Pressure for Platform Piping, Docket No. OPSO-35 (Oct. 15, 1976)* (PHMSA predecessor agency finding that liquid design limitations do not apply to maximum operating pressure requirements for pipelines that have not been replaced, relocated or otherwise changed); *cited In the Matter of Belle Fourche Pipeline Co., Decision on Reconsideration, CPF No. 5-2004-5010 (Jul. 15, 2009)* (noting that the interpretation “remains valid today”).³

In addition, §192.107(b) and Appendix B, Section II, D were never intended to apply—and cannot practicably be applied—to in-service gas pipeline facilities. The testing protocols called for in these regulations reflect the basic understanding that the pipeline will be in the design phase at the time of compliance, *i.e.*, that the pipe will be separated into individual lengths, located aboveground, and easily accessible for physical examination, inspection, and destructive testing. At present, companies simply do not incur the costs of material documentation for gas pipelines that are suggested in the NPRM.

Using those costs as a basis for calculating a cost savings due to the new proposed material documentation requirements (as PHMSA does in the Preliminary RIA) is inconsistent with standard cost/benefit methodology. *Preliminary RIA at p. 122*. In particular, it is not consistent with the public sector cost benefit analysis framework which is based on a baseline scenario that compares the consequences “with” the policy as compared to “without” the policy.⁴ This approach is reflected in numerous federal government documents, including circulars from Office of Management and Budget (OMB) stemming from Executive Order 12866, “Regulatory Planning and Review,” which required that significant regulatory actions be submitted to the OMB. *See E.O. 12866 of Sep. 30, 1993, 58 Fed. Reg. 51735 (Oct. 4, 1993)*.

³ *See also, Letter from R. Beam, OPS, Materials Transportation Bureau, to A. Colabella (Nov. 19, 1984)* (“any pipes (or portion thereof) that were readied for gas service prior to March 13, 1971, and have not been replaced, relocated, or otherwise changed since November 12, 1970 may be used . . . under Part 192 without regard for the material, design, and construction standards (including standards for initial leak or pressure testing and initial inspection).”).

⁴ Cost benefit analysis experts Fuguitt and Wilcox devote a whole chapter to this concept, stating: “Principle 7.1. Cost-benefit analysis is a “with and without” analysis. The analyst should first develop the baseline scenario (*i.e.*, what would happen without the policy) and then identify and calculate incremental benefits and costs by comparing consequences “with” the policy to those “without” the policy.” *Fuguitt & Wilcox, Cost-Benefit Analysis for Public Sector Decision Makers*, p. 58 (1999).

Accordingly, PHMSA erred by including the difference between the cost of material documentation under existing regulatory requirements (§192.107(b)) (the “without” the proposed rule scenario) as a “benefit” and the cost of material documentation as proposed in the NPRM (the “with” the proposed rule scenario), because companies are not incurring those costs currently “without” the proposed rule. In other words, PHMSA has mischaracterized the “without” scenario by assuming that companies with in-service pipelines that have insufficient records to maintain operating pressure, were – due to the existing regulations – excavating the pipeline at every 10 lengths of pipe, doing a cutout, determining material properties by destructive tensile test, and repairing the pipe. Some companies may have been doing this but not due to the existing regulations. As a result, the “without” cost must be zero in order to leave the cost of this proposal equal to the cost of doing the newly required testing.

In sum, despite well-established precedent to the contrary, PHMSA assumed in preparing the Preliminary RIA for this proposed rule that the tensile strength testing requirements in Part 192.107(b) and Appendix B apply to any pipeline that lacks sufficient MAOP documentation under the new undefined “reliable, traceable, verifiable, and complete” standard, including gas pipeline facilities in existence before those rules went into effect. This assumption clearly violates the Pipeline Safety Act’s non-retroactivity provision, 49 U.S.C. §60104(b) and the comparable limitation in the federal gas pipeline safety regulations, 49 C.F.R. §192.13. Accordingly, to comply with the risk assessment, review, and decision-making requirements in the Pipeline Safety Act, 49 U.S.C. § 60102(b)(3)-(5), PHMSA must prepare a new Preliminary RIA which does not assume that the design requirements in §192.107(b) and provisions for steel pipe of unknown or unlisted specification in Section II, D of Appendix B apply to existing gas pipeline facilities.

In any final rule on these issues, PHMSA must clarify that the tensile strength testing requirements in §192.107(b) and Appendix B, Section II, D do not apply to pipelines that lack sufficient documentation to substantiate MAOP under the new undefined “reliable, traceable, verifiable, and complete” standard. These testing requirements are part of PHMSA’s design regulations and cannot be applied retroactively to any “grandfathered” gas pipeline facilities in existence before those regulations went into effect. *49 U.S.C. § 60104(b); 49 C.F.R. §192.13(a)*. Nor do §192.107(b) and Appendix B, Section II, D apply once a pipeline is put into service. The testing protocols prescribed in those regulations can only be implemented at the design phase of a pipeline project, *i.e.*, when the pipe will be separated into individual lengths, located aboveground, and easily accessible for physical examination, inspection, and destructive testing. Requiring operators to perform such testing after a pipeline is installed is impracticable and lacks any support in the text, structure, or history of the regulations (which is precisely why retroactive application of such regulations is prohibited). To the extent that PHMSA establishes new testing requirements for verifying the materials or MAOP of existing pipelines, those requirements can only be applied prospectively. The Agency cannot assume that the tensile strength testing requirements in §192.107(b) and Appendix B, Section II, D apply to existing pipelines in determining the costs and benefits of any such proposal.

B. Inconsistencies with Existing Rules

In addition, many of the newly proposed rules appear either redundant or unnecessary, requiring additional actions **but with no apparent benefit to public safety or pipeline integrity**. The

proposed additions to the corrosion control regulations are just one example. Those rules have been in place for many decades, and over that period of time the number of incidents caused by corrosion and the percentage of incidents caused by corrosion as compared to other causes have significantly declined and remain low today. *PHMSA Incident Trends Statistics*, available at <http://www.phmsa.dot.gov/pipeline/library/data-stats/pipelineincidenttrends>. In contrast to the NPRM Preliminary RIA which simply shows the numbers of incidents since 2003 as compared to the number of all incidents, PHMSA's publicly available gas corrosion incident statistics show a general downward trend in the last 20 years and since 2013 an average of just 16.46% of all gas transmission incidents have been caused by corrosion, down from a peak of 35% in the year 2000. *Id.* These new proposed rules thus are unnecessary or redundant at best, but with an added cost that is not warranted by any identified benefit.

As noted throughout these comments, there are a number of other newly proposed rules that are inconsistent with existing regulations. Thus, instead of adding clarity, they would only present confusion. These include, among other proposals, the gas gathering and recordkeeping provisions.

C. Communications Regarding the Rulemaking Process

API is concerned that PHMSA's methods for clarifying certain aspects of the rulemaking have not allowed sufficient time for stakeholders to process and consider the full impacts of the proposal. PHMSA hosted webinars and briefings on the NPRM, but these came too late in the process to afford sufficient time for interested parties to fully consider the information presented. The recent webinar clarifying the proposal's exemptions for certain gas gathering lines, for instance, was held on June 28, approximately one week before the NPRM comment deadline. The promised recordings from all these webinars were not available until a few days before the deadline. Additionally, the transcripts from the advisory committee meetings on the *Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Proposed Changes* were not available in a timely fashion, yet the discussions at this meeting were necessary to respond to this NPRM. (*NPRM, Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Proposed Changes*, 80 Fed. Reg. 39916, 39920 (Jul. 10, 2015)). The Agency's piecemeal and ad hoc approach to informing the public about its detailed proposal has hampered stakeholder participation and input.

II. Gas Gathering

As a result of the Agency's failure to address congressional mandates and make appropriate use of its longstanding information collection authority, PHMSA lacks the data necessary to support the proposed regulations, and the Preliminary RIA relies on a series of fundamentally flawed assumptions.

PHMSA contends this NPRM will address concerns with the new gas development practices' impact on gathering, difficulties in enforcing API Recommended Practice 80 (RP 80), and the potential for misapplication of that document. *NPRM at 20801-20808*. The NPRM proposes to significantly expand the regulation of gas gathering pipelines by: (1) removing the current reference to API RP 80; (2) replacing API RP 80 with new definitions and some limited guidance for determining whether a pipeline qualifies as an onshore gas gathering line; (3)

extending certain Part 192 requirements to previously-exempt gas gathering lines in Class 1 locations; (4) modifying and adding to the requirements for regulated gas gathering lines in Class 2, 3, and 4 locations; and (5) requiring operators of all gathering lines (whether regulated or not) to comply with the reporting requirements in 49 C.F.R. Part 191. *NPRM at 20827-20828.*

Section 21 of the Pipeline Safety Act of 2011 (2011 PSA) directed PHMSA to conduct a review of the existing federal and state regulations for natural gas and hazardous liquids gathering lines. In preparing this NPRM, PHMSA sought to respond to issues identified in the 2011 PSA as well as recommendations regarding gathering lines from GAO reports. As explained in more detail below, PHMSA has failed to address the congressional directive or the GAO recommendations, however. Despite being under development for four years, PHMSA has not conducted a thorough analysis of the existing rules as required by the 2011 PSA. Nor have they provided any qualitative or quantitative data demonstrating that such gathering lines pose a direct risk to the public. The Agency nevertheless seeks to amend the definition of gathering and significantly expand the scope of regulation to additional gathering lines, far beyond the stated intent in the preamble of the NPRM, with drastic impacts on operators.

Because it has not yet fulfilled relevant recommendations and mandates, the Agency does not have sufficient data to support the regulations it has proposed nor does it have sufficient data to develop those regulations appropriately. As such, the proposal under consideration lacks sufficient justification. API, therefore, respectfully requests that PHMSA collect and analyze additional data, conduct workshops to provide meaningful assessment of any details collected, and prepare a new rulemaking proposal that is consistent with the statutory factors in the PSA and supported by the evidence in the record. Notably, in a rulemaking proceeding for hazardous liquid gathering lines, PHMSA identified that data must be collected to understand any need for regulatory oversight.⁵ Why should a different path be taken for gas gathering?

Recommendations and Mandates Not Addressed

PHMSA has fallen short in addressing the core recommendations in GAO's 2012 and 2014 reports that addressed gathering line issues.⁶ The first report focused on unregulated gathering lines, and the second reviewed all areas of transportation supporting advances in horizontal drilling and hydraulic fracturing, not just gathering lines. GAO's core recommendation relating to gathering pipelines in its first report was that "DOT should (1) collect data on federally unregulated hazardous liquid and gas gathering pipelines and (2) establish an online clearinghouse or other resource for sharing information on pipeline safety practices." *GAO Report 1*, p. 2. The report continues by stating: "Without data on these risk factors, pipeline safety officials are unable to assess and manage safety risks associated with these pipelines." *Id.*

⁵ 80 Fed. Reg. 61610, 61617 (Oct. 13, 2015) ("PHMSA believes that the requirements of the Pipeline Safety Act of 2011 and concerns for adequate regulatory oversight can only be addressed if PHMSA obtains additional information about gathering lines.").

⁶ GAO Report, *Pipeline Safety: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety* (Mar. 2012) (GAO Report 1), available at <http://www.gao.gov/products/GAO-12-388>; GAO Report, *Oil and Gas Transportation: Department of Transportation Is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to Improve Pipeline Safety* (Aug. 2014) (GAO Report 2), available at <http://www.gao.gov/products/GAO-14-667>.

The second report issued by the GAO states: “To address the increased risk posed by new gathering pipeline construction in shale development areas, we recommend that the Secretary of Transportation, in conjunction with the Administrator of PHMSA, move forward with a Notice of Proposed Rulemaking to address gathering pipeline safety that addresses the risks of **larger-diameter, higher-pressure gathering pipelines**, including subjecting such pipelines to emergency response planning requirements that currently do not apply.” [emphasis added] *GAO Report 2, p. 48*. Although, the report does not evaluate or offer any opinion on what should be considered “large diameter” or “high pressure” in the context of the recommendation, PHMSA moved forward with the proposed rule, neglecting the larger-diameter, higher-pressure concept. *Id.*

Similarly, PHMSA has fallen short in addressing the congressional directives in Section 21 of the 2011 PSA, as the report PHMSA issued to Congress on May 8, 2015 did not contain a completed analysis of the sufficiency of the existing rules, as required. Instead, the report merely listed existing regulations applicable to gathering lines.

Lack of Sufficient Data

Industry has recognized the importance of data collection at least as far back as February 2004 when comments submitted regarding the regulation of onshore gathering concurred with collection of incident data on rural onshore gas gathering pipelines. Despite this, 12 years have passed with no additional data collection—data that would have helped all stakeholders to better understand the risk, or lack of, posed by gathering lines, including those unregulated in rural areas.

In addition, PHMSA fails to point to any actual safety data in the record that justifies its proposed changes to the definition of onshore gas gathering line or the criteria for regulating gas gathering lines in Class 1 locations. *NPRM at 20801-20808*. PHMSA also ignores or misrepresents the text, structure, and history of the current regulations, apparently in an effort to create evidence that does not otherwise exist. *NPRM at 20801-20808; Preliminary RIA at 99-117*. API finds these actions particularly troubling because the NPRM has been under development for more than four years, and the Agency is offering proposals that would have a dramatic and lasting effect on the upstream and midstream sectors without data to support these proposals.

Preliminary Regulatory Impact Analysis

The Preliminary RIA makes a number of deeply flawed assumptions about the potential impact of the changes described in the NPRM. *Preliminary RIA at 99-117*. As outlined in the table in Section I.A above, API’s estimates that the total costs of this proposal is \$28.9 billion, in stark contrast to PHMSA’s estimate of \$189.0 million. Many of these costs appear to arise from provisions in the proposal that would cover gathering lines that PHMSA has stated that it did not intend to cover. While verbal clarification on PHMSA’s objectives has been provided since the issuing of the NPRM, the ICF analysis assumes that the proposed gathering lines apply as written, and that significant cost impacts are a result of applying the proposed materials/MAOP verification and MAOP exceedance reporting requirements to gathering. API has an obligation to analyze the NPRM proposals as written. Additionally, and most noteworthy, ICF found that

for small gathering companies, which represent 62% of all gathering companies for a total of 2,223 companies, the annual compliance costs will total 90% of their annual revenue from gathering fees, which is an unbearable burden of government over industry. The flaws in the Preliminary RIA can be traced to PHMSA's decision not to use its longstanding authority to obtain data about gas gathering lines, 49 U.S.C. § 60117(b), as well as the Agency's failure to adequately prepare the gathering line report required under the 2011 PSA. Other flaws appear to be the result of PHMSA's limited understanding or appreciation of the real world implications of the proposals included in the NPRM and inattentive data handling. For example, PHMSA's Table 6-1 in the Preliminary RIA indicates that the data covers incidents on onshore gathering lines when the data actually includes offshore incidents as well. This dramatically increases the number of incidents per mile. When corrected, the number of incidents per 1,000 miles drops by over 50%, directly decreasing the benefit of the proposed regulation. Additionally, PHMSA makes a similar mistake when calculating the costs of incidents in Table 6-6 in the Preliminary RIA. Fixing these errors causes the benefits of the gathering line regulations (Topic Area 8) to drop from \$169.5 million to \$43.3 million. A more detailed analysis of the costs and benefits of this NPRM is included in the ICF report *Cost and Benefit Impact Analysis of PHMSA Natural Gas Gathering and Transmission Regulation Proposal (Jul. 1, 2016)*, prepared on API's behalf and filed in the rulemaking docket.

Specific Gathering Provisions

If the Agency nonetheless decides to move forward with the current proposal, significant modifications must be made before the issuance of a final rule. In trying to address the numerous issues identified, API has organized its responses related to the gathering provisions in the following manner:

- A. Elimination of API RP 80 Incorporation by Reference is Unsupported
- B. Gathering-Related Definitions are Ambiguous
- C. Regulations for 8" and Greater Gathering Lines are Unnecessary
- D. Need to Determine MAOP and Other Evaluation and Recordkeeping Requirements is Inappropriate
- E. Use of Non-Metallics Interpreted to be Disallowed
- F. Technical Drafting Errors Allow for Confusion; Justified Exemptions Not Provided
- G. Request for Associate Administrator Approval is Excessive
- H. Implementation Compliance Deadlines Needed Should be Suitable
- I. Emergency Plan Requirement is Unclear
- J. Dependence on Existing Transmission Line Regulation Affords Obscurity; New Subpart for Regulated Gathering Lines Could be Developed for Simplicity

PHMSA's proposed regulations lack the clarity necessary to understand the intent or applicability of several critical provisions. As presently drafted, gas gathering line operators could be required to comply with PHMSA's proposed pipeline materials and MAOP verification requirements for gas transmission lines. *NPRM at 20828*. Similarly, operators of lower risk gathering lines are required to comply with provisions that are more stringent than those that apply to higher risk gathering lines. *Id.* While some clarity was provided in PHMSA's webinars

conducted during the comment period, there was no formal written communication documenting these clarifications.⁷ Plus, these events were conducted in the latter days of the comment period. API still feels that the presence of these inconsistencies throughout the NPRM raises serious questions about the quality and thoroughness of the rule development process. The Agency's failure to provide clear and meaningful analysis to support its proposals only serves to compound these concerns.

A. Elimination of API RP 80 Incorporation by Reference is Unsupported

API RP 80 is an accredited standard that assists operators in complying with regulations, and its removal of incorporation by reference is unfounded.

PHMSA proposes to repeal API RP 80 and establish a series of new definitions for determining whether a pipeline qualifies as an onshore gas gathering line. *NPRM at 20801-20808*. The NPRM states that these changes are justified because API RP 80 “is difficult for operators to apply consistently to complex gathering system configurations[.]” and “enforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system[.]” *NPRM at 20801*.

API RP 80, which was last reviewed in 2013, remains a current and valid recommended practice that was adopted and reviewed per the requirements of the American National Standards Institute (ANSI) accredited standards process, first in 1999. Additionally, PHMSA acknowledged API RP 80 in a recent rulemaking entitled “Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Amendments.” (*Final Rule, Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Amendments*, 80 Fed.Reg. p.168-188 (Jan. 5, 2015)). PHMSA had the opportunity not to adopt the standard as it did with several others. However, the Agency did not object and failed to raise any concerns regarding the status or positions taken within the document other than those already stated. During the development of API RP 80 in 1999, API members and other stakeholders from industry, public, and government sought to document the discussion relating to gathering in response to DOT request for comment, as well as including other pertinent details from previous discussions with DOT and state regulators. *API RP 80-2000*, p 1. In 1992, and again in 1996, Congress directed the DOT to define gathering and consider the merits of regulating such systems. PHMSA vetted API RP 80 in a multi-year process before incorporating that standard by reference in the March 2006 rulemaking that sought to define and regulate gathering based on risk. *Final Rule, Gas and Hazardous Liquid Gathering Lines*, 68 Fed. Reg. 67129, 67131 (Dec. 1, 2003); *Final Rule, Gas*

⁷ PHMSA held a series of webinars to discuss the proposals in the NPRM immediately prior to the close of the comment period. During those webinars, which were held on June 28 and 29, 2016, PHMSA staff sought to clarify the intended applicability of the proposed gathering line rules. Of particular significance, PHMSA staff indicated that the Agency did not intend to apply the proposed spike test requirements in §192.506 or the pipeline materials or MAOP verification rules in §192.607 or §192.624 to gathering line operators. PHMSA staff also said that the Agency only intends to apply the incident and annual reporting requirements in Part 191 to operators of unregulated gathering lines. PHMSA has indicated that an audio file of the information provided at the webinars will be posted on the public meeting page at <https://primis.phmsa.dot.gov/meetings/>. While API appreciates PHMSA's recent clarifications, the Agency provided this information at the very end of the comment period, and the Association is compelled to provide comments on the text of the rules as proposed in the NPRM.

Gathering Line Definition, 70 Fed. Reg. 57536 (Oct. 3, 2005); *Final Rule, Gas Gathering Line Definition*, 71 Fed. Reg. 13289 (Mar. 15, 2006). Those regulations require operators to use API RP 80, subject to certain additional regulatory limitations, to determine if a pipeline meets the definition of an “onshore gathering line.”⁸ 49 C.F.R. § 192.8, and § 192.9.

As PHMSA acknowledged in the March 2006 rulemaking proceeding, “[t]he pipeline industry . . . expended considerable effort to develop a more precise definition of gathering lines, resulting in the publication of [API RP 80][,]” and “it is unlikely that a new effort would develop a significantly better, or different, definition.” *Draft Regulatory Impact Evaluation* at 5-6. Numerous commenters in this proceeding have expressed continued support for the use of API RP 80, and the Agency does not point to any actual evidence that undermines these statements. Also, even after significant advances in technologies and approaches to production configurations due to the development of shale plays, the concepts, processes, and definitions outlined in API RP 80 are still applicable. This enduring applicability reinforces the resiliency of the document and the importance of retaining the incorporation by reference. Further, there is no evidence in the record to support PHMSA’s claim that enforcement of the federal rules has been hampered by API RP 80. The NPRM and Preliminary RIA do not identify any enforcement actions that illustrate PHMSA’s alleged difficulties in applying that standard in particular cases, and the Agency has not shown any unwillingness or hesitation in providing additional guidance to the regulated community in applying its provisions.⁹ Nothing in the record substantiates the Agency’s assertion that API RP 80 creates a gap that needs to be filled by establishing entirely new definitions in the federal rules.

Finally, the National Technology Transfer and Advancement Act of 1995 (NTTA), 15 U.S.C. § 272(b), and subsequent revisions “directs Federal agencies to use voluntary consensus standards and design specifications developed by voluntary consensus standard bodies instead of government-developed voluntary technical standards when appropriate.” 15 U.S.C. § 272 note; *Revised OMB Circular A-119*, 63 Fed. Reg. 8546 (Feb. 19, 1998); *Periodic Updates of Regulatory References*, 80 Fed. Reg. 168, 168 (Jan. 20, 2015). The Director of the Federal Register is charged with determining whether a proposed regulatory standard to be incorporated by reference serves the public interest. 80 Fed. Reg. 168, 168 (Jan. 20, 2015). PHMSA has provided no evidence as to why API RP 80 now fails to meet the standard established by Congress, nor has the Director of the Federal Register provided information that details why API RP 80 is no longer in the interest of the public.

For all these reasons, API strongly recommends PHMSA reconsider its abandonment of API RP 80. If PHMSA truly intends to eliminate the reference or amend the definition of gathering, additional discussions should occur with industry and other stakeholder groups to determine the appropriate revisions. API and its members stand ready to engage with the Agency and other stakeholders in reviewing and possibly revising API RP 80. Again, the definition of gathering has been debated for nearly 40 years, and API RP 80 is the definition that has received the most

⁸ A gathering line is generally defined in Part 192 as a “pipeline that transports gas from a current production facility to a transmission line or main.” 49 C.F.R. § 192.3.

⁹ See e.g., PHMSA, *Onshore Gas Gathering FAQs*, available at http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_09350AE1C146CC52D5BBABF543878D0D669B0700/file_name/gathering_faqs_7112007.pdf.

broad-based and consistent support. Amending it without a complete and comprehensive understanding of the consequences has the ability to unintentionally and significantly affect operators. API respectfully requests that PHMSA continue to utilize API RP 80 for the purpose of establishing where production ends and where gathering begins and ends.

B. Gathering-Related Definitions are Ambiguous

Industry supports retaining API RP 80 in regulation but is willing to work with PHMSA and other stakeholder groups to modify the gathering-related definitions to improve clarity and consistency.

PHMSA proposes a series of new definitions directly relating to or associated with gathering operations in the NPRM. These definitions are largely required to support the evaluation of production and gathering lines as a direct result of the proposed elimination of the incorporation of API RP 80, which API urges the Agency to reconsider for the reasons set forth above. To the extent PHMSA moves forward with its proposal, however, API requests that the Agency consider revisions to address ambiguities and inconsistencies contained in the proposed definitions. Those revisions include modifying the proposed definitions of “Gathering line (Onshore)” and “onshore production facility or onshore production operation” and creating new standalone definitions for the terms “farm tap” and “incidental gathering”.

1. Onshore production facility or onshore production operation

Consistency in defining terms used in the federal rules is imperative, particularly those that have jurisdictional implications in both compliance and enforcement. The suggested revisions to “*Onshore production facility or onshore production operation*” incorporate many of the well-established principles used in determining the extent of non-jurisdictional production operations under PHMSA’s hazardous liquid pipeline safety regulations at 49 C.F.R. Part 195.¹⁰ PHMSA has consistently relied upon a functional approach in determining the extent of non-jurisdictional production operations for purposes of its regulations, and that philosophy must be carried forward if the Agency ultimately decides to amend the definitions currently established in Part 192.

Similarly, under the current rules, operators are required to use the provisions in API RP 80 to determine if piping and equipment are part of a non-jurisdictional production operation. 49 C.F.R. § 192.8(a). API RP 80 provides that a production operation generally includes “piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids[.]”¹¹ In addition, the federal rules currently prohibit certain dual-use

¹⁰ Part 195 defines the term “production facility” as “piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum . . . or associated measurement.” 49 C.F.R. Part 195.2. The exemption for production facilities is based on a longstanding statutory prohibition originally enacted in the Hazardous Liquid Pipeline Safety Act of 1979. 49 U.S.C. § 60101(22)(B)(ii) (defining “transporting hazardous liquid to exclude onshore production, refining or manufacturing facilities”). See also *Transportation of Liquids by Pipeline*, 46 Fed. Reg. 38257 (Jul. 27, 1981).

¹¹ API RP 80, Section 2.3. A production operation also “includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply[.]” *id.*, as well as “individual well flowlines, equipment piping, transfer lines between production operation

equipment from being classified as part of a production operation. 49 C.F.R. §192.8(a)(1). Specifically, “equipment that can be used in either production or transportation, such as separators or dehydrators” is not part of a production operation “unless that equipment is involved in the processes of ‘production and preparation for transportation or delivery of hydrocarbon gas’ within the meaning of ‘production operation.’” *Id.* Although PHMSA does not have the statutory authority to regulate the production of natural gas, determining where pipeline transportation begins and the equipment involved in transportation is an important step in the process of classifying onshore gas gathering lines.

Pointing to the “ambiguous language and terminology in [API] RP 80,” the NPRM states that “experience has shown that facilities are being classified as production much farther downstream than was ever intended.” *NPRM at 20803*. The record does not contain any specific evidence to substantiate that allegation. Yet PHMSA relies on that unsubstantiated allegation to propose to repeal API RP 80 and establish a new definition of “*Onshore production facility or onshore production operation.*” *NPRM at 20826*.

While API agrees that elimination of ambiguities can assist PHMSA in effectively, efficiently, and fairly enforcing a regulation, nothing will be improved if current perceived ambiguities are simply replaced with new ones. There are aspects of the proposed definition that are inherently ambiguous, such as these phrases: “preparation for transportation does not *necessarily* mean;” “the gas will meet ‘*pipeline quality*’ specifications;” “as *may be commonly understood*,” and “contained in *many contractual agreements*.” *NPRM at 20826*.

Each of these phrases is vague and subject to differing interpretations by the regulated community and PHMSA inspectors, which will result in both compliance and enforcement inconsistencies. To the extent that the Agency intends to move forward with its proposal, certain changes to the proposed definition must be made to provide regulatory certainty and avoid unnecessary adverse impacts on gas producers. Specifically, the following revisions would improve consistency and clarity in determining the extent of non-jurisdictional production operations.

Onshore production facility or onshore production operation means wellbores, equipment, piping, and associated appurtenances ~~confined to the physical acts used for the production, of~~ extraction, or recovery of ~~oil or gas from the ground, earth and~~ the initial ~~separation, dehydration, or processing of produced well fluids, or production compression used to reduce backpressure on the well sending gas to a central production handling facility, in~~ preparation for transportation ~~by pipeline. Preparation for transportation does not necessarily mean the gas will meet “pipeline quality” specifications as may be commonly understood or contained in many contractual agreements.~~ Piping as used in this definition ~~may~~ includes individual well flow lines, equipment piping, ~~and~~ transfer lines between production operation equipment components, ~~and other piping used solely for production operations. Production facilities terminate~~ The production function ends at the furthestmost downstream point where: (1) measurement ~~occurs~~ for the purposes of calculating minerals severance ~~occurs; or there is commingling of the flow stream from two or more wells.~~ (2) the first discharge meter isolation valve located immediately downstream of the point where the flow from two or more wells is comingled; or (3) the first central facility, other than a gas processing plant, where there is production separation, dehydration, compression, sweetening, or processing of well fluids.

equipment elements and sites, and tie-in lines to connect to gathering, transmission, or distribution lines.” *API RP 80, Section 2.4.4(a)*.

Implementing these revisions to the proposed definition will ensure PHMSA's actions align with the jurisdictional determinations under 49 C.F.R. Part 195, actual configurations of production facilities, and sound engineering principles. In addition, these revisions will allow states that are already appropriately regulating these facilities to continue to do so.

a. Jurisdictional Determinations under 49 C.F.R. Part 195

As reflected in the proposed revisions, the list of examples as to what qualifies as an “*Onshore production facility or production operation*” should be expanded to incorporate many of the concepts recognized in the Part 195 definition, including acknowledging that any facilities located upstream from the point of initial separation, dehydration, or processing are part of the production function. These facilities (including flow lines) are exempt from regulation under Part 195, and a similar allowance should be recognized in Part 192 to avoid inconsistency in jurisdictional determinations of production operations, particularly in areas that produce significant quantities of hydrocarbon gas and liquids at the wellhead. At the same time, the list of examples as to what qualifies as production piping must be revised to ensure that the definition is not unnecessarily restrictive. Under the language proposed in the NPRM, piping used to provide fuel gas or to support other kinds of production operations could be excluded from the definition; therefore, to avoid that result, any piping “used solely for production operations” must be included within the scope of the definition.¹² The proposed definition should also be modified to add a third potential endpoint for the production function. That endpoint is the first central facility used to permanently separate, dehydrate, or otherwise process well fluids, which is the point where the production function traditionally ends under Part 195. Part 192 also uses a similar endpoint in determining the extent of unregulated offshore operations in State waters. 49 C.F.R. § 192.1(b)(1).

Like API RP 80 and the framework currently used to determine the extent of unregulated production operations under Part 192, the Part 195 definition of a production facility is functional in nature. As PHMSA explained in 1986, the “number of interconnected leases from which hydrocarbons are produced is not a factor in identifying a facility as a production facility.” *Final Rule, Hazardous Liquids Gathering Lines in Rural Areas*, 51 Fed. Reg. 15005, 15007 (Apr. 22, 1986) (adding the definition of “production facility” to Part 195). Rather, “[f]acilities are designated as production facilities according to their usage, not the location of wells from which hydrocarbons are being produced.” *Id.* In applying the Part 195 definition, PHMSA has generally found that the production function ends at the outlet of the first facility used to permanently separate produced well fluids. See e.g., *PHMSA Letter of Interpretation to Barney V. Dotson, BP Exploration (Alaska), Inc.* (Oct. 11, 1994).¹³ PHMSA has previously concluded that the production function can extend beyond the initial point of permanent separation, however, to a centralized processing facility used for the stabilization and temporary storage of condensate. *PHMSA Letter of Interpretation to A. Soto* (Jun. 4, 2007). Gas sweetening and

¹² The introduction of the term “solely” in describing what qualifies as production piping will prohibit operators from using the production facility classification for dual-use piping, i.e., piping that can be used for production or transportation purposes, which has previously been identified as a concern by PHMSA.

¹³ See also *PHMSA Interpretation for BP Exploration (Alaska), Inc.* (Jul. 22, 1996); *PHMSA Interpretation Letter for Forest Oil Corp.* (May 17, 2002)

liquids extraction from hydrocarbon gas are included within the scope of “separation” and “treatment” as those terms are used in the Part 195 definition of production facility. *51 Fed. Reg. 15005, 15007* (Apr. 22, 1986). PHMSA has also recognized that the production function extends beyond the two points identified in the NPRM in many cases, including in circumstances where additional processing is necessary to prepare hydrocarbons for transportation by pipeline.¹⁴

b. Actual Configurations of Production Facilities

In addition to ensuring consistency with Part 195, API’s proposed revisions to the definition of “Onshore production facility or onshore production operation” correspond with the actual configurations of production facilities across the country, while also providing more defined lines of demarcation in determining when the production function ends. API believes the proposed revisions will allow for the application of the new definition across the many different types of production function, without significantly extending the endpoint. API also believes it is imperative that the diagrams illustrating the application of API RP 80 be retained along with API’s proposed revisions to PHMSA’s proposal, or, alternatively, that the Agency develop similar diagrams to clearly illustrate how the new definitions will be implemented. Without those diagrams, there is a significant risk of inconsistent application of the definitions across the industry.

For instance, Figure B-1 from API RP 80 illustrates three different kinds of production operations and where the line of demarcation from production to gathering is for each of those configurations. The revisions API has proposed to the definition of onshore production facility are consistent with these diagrams, which have been used by the industry since API RP 80 was implemented.

¹⁴ To be part of a production facility under the Part 195 definition, “piping or equipment must be used in the process of extracting petroleum . . . from the ground . . . and preparing it for transportation by pipeline.” *Id.* “Flow lines,” *i.e.*, pipelines “found at production sites . . . [that] move produced hydrocarbons from a well to a point where gas, oil and water are separated[,]” are considered production facilities under Part 195. *Transportation of Hazardous Liquids by Pipeline: Regulation of Intrastate Pipelines*, *50 Fed. Reg. 15,895, 15,896* (Apr. 23, 1985). PHMSA amended the federal pipeline safety rules in 1985 to make clear that onshore flow lines are production facilities exempt from regulation under Part 195. In justifying that decision, PHMSA noted that there was “no information . . . indicating a pressing need to regulate flow lines,” and that “a reading of the legislative history of the HLPSSA tends to support a conclusion that Congress intended flow lines to be excluded from regulation as part of onshore production.” *Id.*

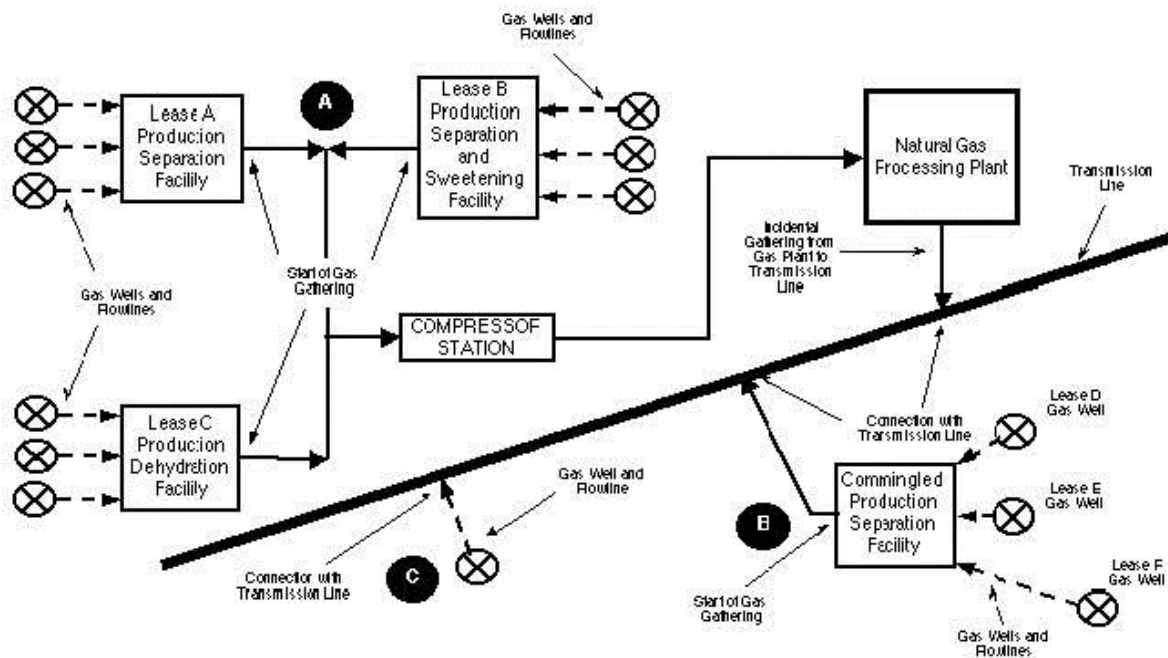


Figure B-1-Examples of Common Gas production and Gathering Operations, API RP 80-2000, Appendix B Applications, p. 21.

In Scenario A, production from individual wells on a lease is moved via pipeline to a “central” separation, sweetening and/or dehydration facility. These facilities, which are generally required so that the producer can begin the initial treatment of its production to meet the quality specifications of a gatherer or gas processor, do not rise to the level of a “gas processing plant” as defined in the regulations. It is logical that production would end at the outlet of such a facility, as the gas generally will not be of acceptable quality for gathering absent this “preparation for transportation.” Scenario B is similar, except that production from a number of leases is moved to a centralized separation or other facility.

In addition, Figure B-8 from API RP 80 also provides much needed clarity for more current trends in production operations, particularly in many of the new unconventional developments. In these scenarios, the producer moves production from various well pads to a larger, more centralized production facility. Again, the purpose of these facilities is to provide for the initial treatment of the gas so that it can be accepted by the downstream gatherer or processor. In essence, for larger production operations, these central production facilities are where production from multiple wells are commingled and treated together, for more cost-effective and efficient operations.

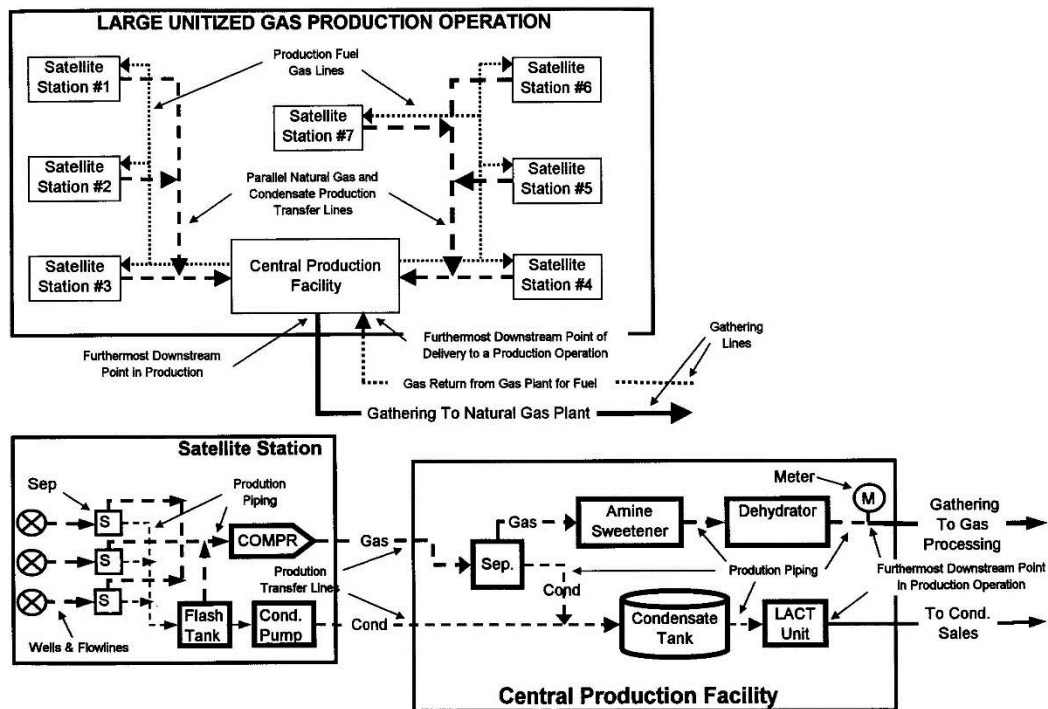


Figure B-8-Example of a Central Production Facility With Satellites Figure B-1-Examples of Common Gas production and Gathering Operations, API RP 80-2000, Appendix B Applications, p. 33.

c. Sound Engineering Principles

API's proposed revisions accurately reflect the technical aspects associated with the operation of these assets, which PHMSA's proposed rule fails to do. Production facilities are an integral part of getting the raw materials, or well stream, from the well, separating the fluids into phases (*i.e.* oil or liquid hydrocarbons, gas, and water), and then removing impurities that affect the marketability of these fluids prior to the custody transfer for sale or delivery. A production facility can extend from the well head through the multiple steps, which the well stream may go through, to generate marketable products. In order to meet several requirements or take advantage of equipment, these steps may include measurement or commingling with other wells. "Production" does not have to end at the first measurement point or the first commingling point because, again, the purpose of a production facility is to take the well stream from the well bore, separate it into its primary components, and then, treat those components as necessary.

Further, a production facility can range in complexity based on the physical and chemical properties of the well stream. The facility can range from a single well producing marketable natural gas to a cluster of wells connected by flow lines to a central production facility whose production contains oil, liquid hydrocarbons, highly volatile liquids (HVL), and salt water.

Central production facilities processes include: separation, mechanical coalescing, electrostatic coalescing, gas treatment (H₂S treatment, CO₂ removal, nitrogen removal, and helium removal), chemical injection, liquid pumping, gas production compression (enhancing production by reducing well back pressure, enhancing phase separation, or assisting in delivery into a gathering system), dehydration, filtration, water injection, CO₂ injection, gas injection, steam generation and injection, flaring, oil storage, water storage, NGL storage, truck loading, and measurement. In many cases, the phases of production are measured prior to many of the stages of production treatment. These facts all provide justification for API's proposal that the end of production be defined to occur at the isolation valve downstream of the final meter after the furthestmost downstream production facility used to measure the finished products prior to delivery for transportation into a pipeline system.

d. Potential Preemption of State Regulation

Many states have already developed safety standards that apply to oil and gas production operations, and those standards could be preempted if PHMSA extends its jurisdiction closer to the wellhead. There are many state authorities that regulate the safety of production operations and that have standards in place for piping.¹⁵ Under the definition proposed in the NPRM, the PSA's preemption provision would likely render those state safety standards void and unenforceable. That issue is not even considered in the NPRM or Preliminary RIA, further demonstrating that PHMSA should defer this rulemaking proposal or at the very least significantly modify its proposed definition of "*Onshore production facility or onshore production operation.*" *NPRM at 20823.*

2. "Gathering line (Onshore)"

PHMSA is proposing to create a new definition in Part 192 for the term "*Gathering line (Onshore).*" API finds serious concern with that proposal and requests that the below proposition be considered for reasons further explained after:

Gathering line (Onshore) means a ~~pipeline, or a connected series of pipelines and equipment used to collect gas from the endpoints of a production facility/operation and transport it to the furthestmost point downstream of the endpoints described in paragraphs (1) through (4) of this definition:~~

~~(1)~~ (1) pipeline used to collect and transport gas from the endpoint of an onshore production facility/ or onshore production operation to the furthestmost point downstream of the following endpoints:

~~(1) (A)~~ (A) The inlet of 1st gas processing plant, unless the operator ~~submits a request for approval to the Associate Administrator of the Pipeline Safety that~~ demonstrates, using sound engineering principles, that gathering extends to a further downstream plant ~~other than a plant located on transmission line and the Associate Administrator of Pipeline Safety approves such request;~~

~~(2) (B)~~ (B) The outlet of the furthestmost downstream gas treatment facility ~~that is not associated with a processing plant or compressor station;~~

~~(3) (C)~~ (C) The furthestmost downstream point where gas from the same or separate production fields are commingled, provided the ~~distance between the interconnection of the fields~~ may not be more than does not exceed 50 miles from each other unless the Associate Administrator of Pipeline Safety, or the appropriate state agency, finds a longer separation distance is justified in a particular case; or

¹⁵ See e.g., *Ohio Admin. Code 1501:0-1-01 et seq.* (Ohio regulations applicable to pipelines used in oil and gas production); *W. Va. Code R. § 35-4-1 et seq.* (West Virginia regulations applicable to oil and gas production).

- ~~(4) (D) The outlet of the~~ Outlet of the furthestmost downstream compressor used to facilitate delivery into a pipeline, other than another gathering line.
- (2) pipeline used for incidental gathering or that transports gas to production or gathering facilities for use as fuel, gas lift, or gas injection gas.

The following clarifications and changes address operational conditions, align federal regulations for the oil and gas pipeline industry, improve clarity, and ensure consistent compliance and enforcement as well as avoid significant adverse impacts on the midstream industry:

a. New Definition Greatly Differs from Current Industry Practice

PHMSA adopted changes to Part 192 in March 2006 that resulted in a multi-step framework for determining whether a gas pipeline is an onshore gathering line and, if so, whether any portions of the line are regulated under Part 192. 49 C.F.R. § 192.8; §192.9. This effort allowed for the incorporation of API RP 80, which under the current definition in API RP 80, an “onshore gathering line” is defined as “any pipeline or part of a connected series of pipelines” that “transport[s] gas from the furthestmost downstream point in a production operation to the furthestmost downstream” point in one of the following five locations:

- *Gas Processing Plant.* “[T]he inlet of the furthestmost downstream natural gas processing plant, other than a natural gas processing plant located on a transmission line.”
- *Gas Treatment Facility.* “[T]he outlet of the furthestmost downstream gathering line gas treatment facility.”
- *Point of Commingling.* “[T]he furthestmost downstream point where gas produced in the same production field or separate production fields is commingled.”
- *Compressor Station.* “[T]he outlet of the furthestmost downstream compressor station used to lower gathering line operating pressure to facilitate deliveries into the pipeline from production operations or to increase gathering line pressure for delivery to another pipeline.”
- *Incidental Gathering.* “[T]he connection to another pipeline downstream of . . . ” these endpoints or the furthestmost production operation.

API RP 80, Section 2.2(a)(1); see also 49 C.F.R. § 192.8(a) (requiring operators to use API RP 80 to determine if a pipeline is an “onshore gathering line”).

Part 192 imposes three additional regulatory limitations on API RP 80’s definition of the endpoint of a gathering line to address potential concerns with the misapplication of the furthestmost downstream concept:

- *Gas Processing Plant.* “The endpoint of gathering . . . may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.” In adopting this limitation, PHMSA stated “many of our prior interpretations have based the end of gathering on the first downstream processing plant.”

- *Point of Commingling.* “If the endpoint of gathering . . . is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case.”
- *Compressor Station.* “The endpoint of gathering . . . may not extend beyond the furthestmost downstream compressor used to increase gathering line pressure for delivery to another pipeline.”¹⁶

The NPRM states that the current framework for determining whether a pipeline qualifies as an onshore gas gathering line “is difficult for operators to apply consistently to complex gathering system configurations[,]” and that “[e]nforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system, which can lead to misapplication of the incidental gathering line designation.” *NPRM at 20801*. The NPRM further states that PHMSA and the National Association of Pipeline Safety Representatives (NAPSR) voiced some of these concerns prior to issuing the March 2006 final rule and that PHMSA expressed its intent to clarify the application of the incidental gathering line designation in a future rulemaking proceeding in recent letters of interpretation. *NPRM at 20803, 20807*. To address this, the NPRM proposes to no longer utilize API RP 80 and create a new Part 192 definition of an onshore gas gathering line that modifies the existing regulatory definition in at least seven ways. *NPRM at 20825*.

API submits that PHMSA’s reliance on API RP 80 should be reinstated or, in the alternative, that a number of modifications be made to the definition of “Gathering Line (Onshore),” as well as the inclusion of additional definitions for “incidental gathering” and “farm taps.” API observes that many of the concepts included in the Agency’s proposed definition of “*Gathering line (Onshore)*” appear to be consistent with the approach taken in API RP 80 and the current federal rules. That includes the use of the furthestmost downstream concept and incorporating the first four potential endpoints of the gathering function. To avoid any future uncertainty, and whether or not the Agency accepts API’s suggested modifications, PHMSA should clearly affirm that it is in fact re-codifying the longstanding industry practice and understanding in applying these principles to determine the classification of onshore gas gathering lines.

b. Incidental Gathering Line Designation and Need for Standalone Definition

Under PHMSA’s proposed definition for “*Gathering Line (Onshore)*,” operators would only be able to use the incidental gathering line designation in three narrow circumstances, *i.e.*, if a gathering line downstream of the four identified endpoints: (1) “does not leave the operator’s facility surface property (owned or leased, not necessarily the fence line);” (2) “does not leave an adjacent property owned or leased by another pipeline operator’s property—where custody transfer takes place;” or (3) “does not exceed a length of one mile, and it does not cross a state or federal highway or an active railroad.” *NPRM at 20825*.

¹⁶ 49 C.F.R. § 192.8(a)(2)-(4).

Contrary to PHMSA's assertion in the rulemaking that the use of the incidental gathering line designation is a misapplication of API RP 80 and the Federal rules, API RP 80 appropriately recognizes that incidental gathering lines are a continuation of the gathering process from a functional perspective. *API RP 80, Section 2.2.1.2.6 (discussing incidental gathering); Figure B-1 (recognizing use of incidental gathering designation for pipeline connecting natural gas processing plant to transmission line).* API strongly urges PHMSA adopt a clear, standalone definition of incidental gathering that aligns with the concepts in API RP 80,¹⁷ which has been acknowledged and accepted by the Agency. API proposes the following as a standalone definition to be added to §192.3 as well as an addition to the proposed definition of "Gathering Line (Onshore)":

§ 192.3 Definitions.

Incidental Gathering means the additional downstream gathering pipeline needed to connect the outlet of an identified gathering endpoint with a transmission line, distribution line, or other pipeline facility.

Gathering line (Onshore) means a ~~pipeline, or a connected series of pipelines and equipment used to collect gas from the endpoints of a production facility/operation and transport it to the furthestmost point downstream of the endpoints described in paragraphs (1) through (4) of this definition:~~

(1) * * *

(2) pipeline used for incidental gathering or that transports gas to production or gathering facilities for use as fuel, gas lift, or gas injection gas.

PHMSA has acknowledged in guidance that API RP 80's incidental gathering line designation can be used under the current federal rules. *71 Fed. Reg. at 13292; PHMSA Interpretation for CDX Gas (Jul. 14, 2009). See also PHMSA Interpretation for Kansas Corporation Commission (Jul. 30, 2009).* At the same time, the NPRM states that "PHMSA has also identified a regulatory gap that permits the potential misapplication of [API RP 80's] incidental gathering line designation . . ." *NPRM at 20807.* The NPRM further states that PHMSA and NAPSRS voiced some of these concerns prior to issuing the March 2006 final rule and that PHMSA expressed its intent to clarify the application of the incidental gathering line designation in a future rulemaking proceeding in recent letters of interpretation.

Another concern of PHMSA with the incidental gathering line designation is the potential impact of the exemption for Class 1 gas gathering lines, particularly for larger diameter lines operating at a maximum pressure that exceeds 20 percent or more of Specified Minimum Yield Strength (SMYS). API suggests that if data exist that fully justify that concern then the appropriate response is instead to apply certain safety standards to those lines, not to arbitrarily restrict the use of the incidental gathering line designation or require the wholesale reclassification of pipeline systems in the midstream sector.

If the Agency nonetheless intends to pursue its proposed changes, API suggests that PHMSA instead require that operators of incidental gathering lines comply with the requirements applicable to Type A, Area 1 gas gathering lines as opposed to arbitrarily restricting the use of them or requiring the wholesale reclassification of pipeline systems in the midstream sector. The

¹⁷ API RP-80 Section 2.2.1.2.6 at p. 5 (2013).

transition from unregulated status to compliance with all of the transmission line regulations is clearly not adequately addressed in the proposed regulations. While not without its own unnecessary burdens, requiring incidental gathering line operators to comply with the provisions for Type A, Area 1 gas gathering lines is a much more achievable objective.

In addition, an extended compliance deadline must be provided if PHMSA proposes any restriction on the use of incidental gathering line designation that would require operators to reclassify these lines as transmission. Such an action would represent a dramatic change in the regulatory burden imposed on the midstream industry, and operators of affected pipeline systems will need an appropriate amount of time to achieve compliance. Therefore, the proposed rule must be modified to include a 5-year compliance deadline to the extent that incidental gathering lines are reclassified as fully-regulated transmission lines.

Contrary to the requirements in the PSA, PHMSA does not provide any technical basis or specific reasoning to support the imposition of these particular restrictions in the NPRM or Preliminary RIA. 49 U.S.C. §§ 60101(b); 60102(b)(2). In addition, the Preliminary RIA assumes that these proposed restrictions are consistent with the intent of the March 2006 final rule and, therefore, would impose no additional cost on the midstream industry. *Preliminary RIA at 100*. That assumption is directly contradicted by the rulemaking history, which clearly recognizes that the use of the incidental gathering line designation has been allowed under the current federal rules for more than a decade. 71 Fed. Reg. at 13292 (Mar. 15, 2006); PHMSA Interpretation for CDX Gas (Jul. 14, 2009); PHMSA Interpretation for Kansas Corporation Commission (Jul. 30, 2009). Nor is there any indication that PHMSA ever discussed the limitations proposed in the NPRM in the previous rulemaking proceeding. Accordingly, the Preliminary RIA's assumption that the NPRM proposal is consistent with the intent of the March 2006 final rule is wholly without merit.

Likewise, the Preliminary RIA erroneously assumes that PHMSA's proposed restrictions would not have a substantial impact on the classification of gathering lines. *Preliminary RIA at 100*. In a July 2009 interpretation, PHMSA found that an 8-mile pipeline extending from the outlet of a central processing and compression facility to a third-party transmission line was an incidental gathering line. PHMSA Interpretation for CDX Gas (Jul. 14, 2009). If PHMSA adopts the restrictions proposed in the NPRM, the entire 8-mile pipeline segment considered in that interpretation would need to be reclassified as a transmission line. The operator would also need to comply with a series of new regulations, including the gas transmission integrity management program requirements in Subpart O and the new pipeline materials, MAOP verification, and corrosion control provisions proposed in the NPRM. In other words, the compliance implications for just one operator would be very dramatic. Given the widespread presence of this kind of pipeline configuration throughout the United States, the proposed rule's failure to provide an appropriate scope, would impose an unreasonable, and unjustified burden, with no corresponding benefit.

Nonetheless, the Preliminary RIA does not consider the effect of reclassifying incidental gathering lines as transmission in analyzing the potential regulatory impact of PHMSA's proposed definition. There is no attempt to analyze the number of pipeline operators or mileage affected or to estimate the potential costs, benefits, or other implications of requiring the

reclassification of these pipeline segments as transmission lines. Nor does the NPRM include any proposal to facilitate the transition of these assets from the gathering to the transmission rules in Part 192, *e.g.*, the proposed MAOP regulation does not include a grandfather clause that would allow a previously-exempt incidental gathering line that becomes a transmission line to establish an MAOP based on the highest actual operating pressure experienced during a previous five-year period. As a result, each operator would need to determine a design pressure, conduct a hydrostatic pressure test, and consider the entire operating history of the pipeline to establish an MAOP under Part 192.

Perhaps most significantly, the NPRM and Preliminary RIA do not consider the potential impact of allowing operators to continue using the incidental gathering line designation if PHMSA adopts its proposed regulations for gas gathering lines in Class 1 locations. The comments offered in this proceeding suggest that the primary concern with the incidental gathering line designation is the ancillary effect of the exemption for Class 1 gas gathering lines, particularly for larger-diameter, higher-pressure lines. To the extent that concern is legitimate, the appropriate response is for PHMSA to apply certain safety standards to those lines on the basis of risk, not to arbitrarily restrict the use of the incidental gathering line designation or require that these pipelines be indiscriminately reclassified as transmission lines. API suggests a cautious approach is particularly warranted here, given the absence of actual data on the risk posed by gas gathering lines and the erroneous assumptions included throughout the Preliminary RIA.

c. Need for Standalone Definition for “Farm Tap”

PHMSA informally proposes to add an embedded definition in the “Gathering line (Onshore)” definition – not separately included in 49 C.F.R. §192.3 – for farm taps that provide gas in conjunction with gathering lines. API suggests that it is inappropriate to combine the two concepts. Specifically, the NPRM proposes to state, as part of the “Gathering line (Onshore)” definition in § 192.3, that:

Pipelines that serve residential, commercial, or industrial customers that originate at a tap on gathering lines are not gathering lines; they are service lines and are commonly referred to as farm taps.

NPRM at 20825.

While the Agency’s clarification arguably reflects its position taken in recent years, it is inconsistent with historical practice, and the language proposed in the NPRM would create uncertainty for pipeline operators if adopted as a final rule without modification. Accordingly, if proper regulatory characterization of a farm tap is warranted, PHMSA should promulgate a separate definition in Part 192, either in the parallel proceeding relating to the distribution integrity management program (DIMP) requirements or in the current proceeding as suggested below.

API submits that an appropriate, standalone definition is as follows:

§ 192.3 Definitions.

Farm Tap means a service line that provides gas from a tap on a production, gathering, or transmission line to residential or agricultural customers.

This revision is necessary for several reasons. First, PHMSA's proposed definition implies that all pipelines that deliver gas from a gathering line to a consumer must be classified as service lines. PHMSA itself acknowledges in the NPRM, however, that many pipelines that deliver gas directly from gathering lines to large volume customers, such as factories, power plants, and institutional users of gas, are transmission lines, *not* distribution lines.

Second, the language proposed in the NPRM departs from the guidance offered by PHMSA in describing farm taps in other contexts. For example, in a July 10, 2015 NPRM that would create an exception from the DIMP requirements for farm taps, the Agency suggested that a "'farm tap' is industry jargon for a pipeline that branches from a transmission, gathering, or production pipeline to deliver gas to a farmer or other landowner." *NPRM, Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Proposed Changes*, 80 Fed. Reg. 39916, 39920 (Jul. 10, 2015). Despite its prior statements, the definition PHMSA proposes in the current NPRM is far more expansive and would not only classify pipelines that deliver gas to commercial and industrial customers as farm taps but would also characterize them as service lines.¹⁸

3. *Gas processing plant*

While the issue is not discussed at all in the NPRM or Preliminary RIA, PHMSA's proposed definition of "gas processing plant" appears to be consistent with the approach taken in the current federal rules, API RP 80 and the Agency's draft Frequently Asked Questions for Midstream Processing (Midstream Processing FAQs). *NPRM at 20825*. Accordingly, API requests that PHMSA clearly affirm that understanding and make other clarifying amendments to the regulation before codifying the proposed definition in §192.3 to avoid future uncertainty.

API proposes the following revisions to the proposed definition in §192.3:

§ 192.3 Definitions.

Gas processing plant means a natural gas processing operation, other than production processing, operated for the purpose of extracting entrained natural gas liquids and other associated non-entrained liquids from the gas stream. **This definition** does not include a natural gas processing plant located on a transmission line, commonly referred to as a "straddle plant."

API also proposes the following change to the scope limitations in 49 C.F.R. § 192.1 to accomplish that objective:

¹⁸ PHMSA does not even acknowledge or reconcile the fact that the proposed definition would impact the parallel proceeding relating to the exception for farm taps from the DIMP requirements.

§ 192.1 What is the scope of this part?

(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to—

(1) * * *

(6) Gas processing plants.

The Agency has long recognized these practices, and such a provision for gas processing plants is included in API RP 80. *API RP 80, Section 2.2.1.2.1.*

PHMSA's addition of a provision acknowledging that gas processing plants are not subject to regulation under 49 C.F.R. Part 192 would be consistent with the PSA's lack of jurisdiction within those plants and align with the Agency's draft Midstream Processing FAQs.

4. Gas Treatment Facility

PHMSA should also make the following non-substantive change to improve the clarity of the proposed definition of a "gas treatment facility:"

§ 192.3 Definitions.

Gas treatment facility means one or a series of gas treatment operations, operated for the purpose of removing impurities (e.g., water, solids, basic sediment and water, sulfur compounds, carbon dioxide, etc.). **This definition does not include gas treatment operations that is not** associated with a processing plant or compressor station **and is not or a gas treatment facility** on a transmission line.

Although the definition of "gas treatment facility" is not discussed in the NPRM or Preliminary RIA, PHMSA's proposal appears to be consistent with the approach taken in the current Federal rules and API RP 80. *NPRM at 20825.* PHMSA should clearly acknowledge that fact before codifying the proposed definition in Part 192 to avoid future uncertainty or ambiguity.

C. Regulations for 8" and Greater Gathering Lines are Unnecessary

PHMSA's inclusion of 8" and greater gathering lines contradicts a risk-based approach and has no merit.

PHMSA's only stated purpose for including gas gathering in the NPRM is to address recent developments in natural gas exploration and production. *NPRM at 20801.* The NPRM states that operators are constructing shale gas gathering lines that far exceed historical operating parameters, particularly from a pressure and diameter perspective. *Id.* The NPRM explains that PHMSA did not foresee or consider the risks associated with these kinds of gathering line systems in developing the March 2006 final rule, and recent GAO recommendations provide further support for the proposed regulations.

API firmly maintains that the criteria for determining the regulatory status of Class 1 gas gathering lines must be changed before a final rule is issued in this proceeding. Gas gathering

lines that are 16 inches in outside diameter and operate at a maximum pressure of 20 percent or more SMYS have the potential to pose a higher risk, and therefore greater consequence, and should be targeted for regulation.

In addition, API suggests that expansion of gathering line regulation be more clear and transparent than the proposal. As currently written, stakeholders struggle to distinguish, or even discuss, the differences between Type A, Area 1 and Type A, Area 2 lines. The easiest way to bring clarity is accomplished through the creation of a “Type C” class of pipelines instead of the currently proposed “Type A, Area 2.” API’s proposed revisions to NPRM proposed §192.8(c) are reflected below:

§ 192.8(c) How are gathering lines and regulated onshore gathering lines determined?

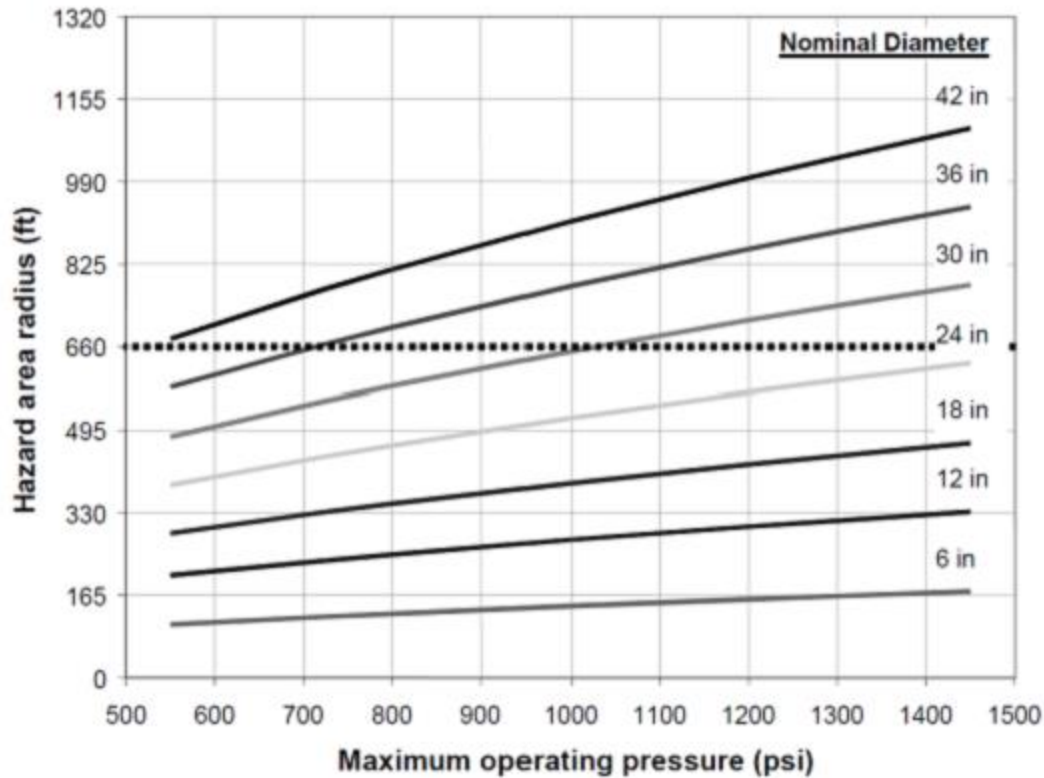
Type	Feature	Area	Safety buffer
A	—Metallic and the MAOP produces a hoop stress of less than 20 percent 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part —Non-metallic and the MAOP is more than 125 psig (862 kPa).	Area 1. Class 2, 3, or 4 location (see §192.5) Area 2. Class 1 location with a nominal diameter of 8 inches or greater.	None.
B	Non-metallic Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. —Non-metallic and the MAOP is 125 psig (862 kPa) or less.	Area 1. Class 3 or 4 location Area 2. An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location. (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings; or (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings	None. If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2 (b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.

C	<u>—Metallic gathering lines 16” and greater with a MAOP that produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part.</u> —Non-metallic lines 16” and greater and the MAOP is more than 125 psig (862 kPa).	<u>Class 1 location</u>	<u>None.</u>
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Other than citing the 2010 NAPSRR resolution and a 2014 GAO recommendation, which specifically references emergency response preparedness for higher-pressure, larger-diameter lines, PHMSA provides no analytical support for the criteria used to trigger the regulation of Class 1 natural gas gathering lines in the current proposal. Significantly, there is no justification or analysis provided in selecting the eight-inch outside diameter requirement proposed in the regulations. Thus, the decision to regulate pipelines that are eight inches or greater amounts to no more than an arbitrary proposal by PHMSA not linked to any verifiable proof that the proposal will increase safety.

PHMSA has traditionally used a risk-based philosophy in developing its regulatory programs, including integrity management since 2002 and regulation of jurisdictional gathering lines since 2006. PHMSA’s authority to regulate rural gathering lines, *i.e.* those that are outside the limits of any incorporated or unincorporated city, town, or village, any other designated residential or commercial area, or any similarly populated area that the Secretary of Transportation determines to be a non-rural area, is limited by statute. *49 U.S.C. 60101 (21)(B)*. This restriction is rightly imposed, as lines in rural areas do not pose the same risk to the public and the environment.

The NPRM proposes to regulate rural gathering lines that do not present an increased risk to public safety or the environment. A report, Gas Research Institute -00/0189, *Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines*, was completed in 2000 through collaboration between C-FER Technologies and the Gas Research Institute, and it details the research behind the Potential Impact Radius (PIR) definition. This report is a part of ASME/ANSI B31.8S, which is incorporated by reference. *ASME B31.8S, Section 3.2, Potential Impact Area p. 7*. The determination of PIRs aligns with the regulators’ risk-based philosophy, focusing resources on the highest risk assets. However, the NPRM calls for regulation of gathering lines that are eight inches and greater in diameter despite the fact that, as reflected in the graphic below from GRI-00/0189, this lower diameter pipe produces a much smaller impact radius.



GRI-00/0189, *Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines*, 2000, Figure 2.4 Proposed hazard area radius as a function of line diameter and pressure.

In fact, the table below shows PIR calculations for a common flange rating, 1480 psig, and as shown, the sizes of pipe proposed for regulation do not correspond with pipelines that PHMSA characterizes as high-risk:

p	d	PIR
1480	14	371.63
1480	12	318.54
1480	10	265.45
1480	8	212.36

Where:

p=Maximum Allowable Operating Pressure (MAOP) in psig.

d=nominal diameter in inches.

PIR=potential impact radius in feet.

Although many gathering lines have indeed been recently built to support the development of various shale plays, the majority of these lines are operating at a fraction of their design pressures. Companies manage gathering line assets this way for several reasons, including the unique production curves of shale reservoirs, which produce much more oil and natural gas initially but taper off in the later stages of production. The proposed rulemaking fails to take into consideration that operators are purposely engineering these systems to conservatively account for the differing reservoir pressures the gathering line will see throughout the life of the well.

Additionally, PHMSA's proposal fails to acknowledge that the rules in place today already address the perceived risk of larger diameter gathering lines that operate at a higher percentage of SMYS. One of the largest shale plays is the Barnett Shale near Fort Worth, Texas. For example, gathering lines in the large Barnett Shale play near Fort Worth, Texas, are all regulated, regardless of their size, under existing requirements because they were built in Class 2, 3 and 4 locations.

In those rural areas, or Class 1 locations, where the shale development areas are found, the appropriate state regulatory agency has had every opportunity to regulate those systems appropriately—and they have. Additional regulations have been adopted in North Dakota, Ohio, and Colorado, and these address an earlier stated concern that PHMSA has failed to fulfill congressional mandates, as some regulations have been adopted since that report was finalized.

D. Need to Determine MAOP and Other Evaluation and Recordkeeping Requirements is Appropriate

No benefit is achieved by calculating MAOP for unregulated gathering; likewise, the indiscriminate application of the other federal reporting requirements to gathering line operators is unlawful and unjustified.

The NPRM proposes to apply the requirement for reporting of MAOP exceedances to unregulated gathering lines. *NPRM at 20824.* To comply with such a requirement, operators of those lines would need to establish an MAOP under 49 C.F.R. §192.619(a)-(d). The following three additional operating conditions must also be reported to the Agency:

- Section 191.23(a)(1) relating to those gathering lines operating at a hoop stress of 20 percent or more of SMYS where general corrosion has reduced wall thickness to less than that required for the MAOP and localized corrosion pitting to a degree where the leakage may result;
- Section 191.23(a)(2) relating to unintended movement of abnormal loading by environmental causes - earthquake, landslide, flood, that impairs serviceability; and
- Section 191.23(a)(8) relating to any safety-related conditions that could lead to an imminent hazard and causes a 20 percent or more reduction in operating pressure.

Additionally, gathering line operators must comply with all of the 49 C.F.R. Part 191 reporting requirements, whether gathering lines are regulated or not, with the only exception being the obligation to submit data to the National Pipeline Mapping System. *NPRM at 20824.* Finally, the NPRM proposes to require all gathering line operators to submit information to the National Operator Registry.

As further explained below, API requests that the proposed rule be modified to exempt unregulated gathering line operators from the obligation to submit safety-related condition reports, including for MAOP exceedances. PHMSA clarified in a series of webinars held immediately prior to the end of the comment period that the Agency did not intend to apply the safety-related condition reporting requirements to operators of unregulated gathering lines. API fully supports that clarification and is offering text to that effect for PHMSA to consider adopting in the final rule.

API also requests that PHMSA modify the annual reporting requirement to ensure that the information sought from gathering line operators does not impose unnecessary burdens on the regulated community, which may have the unintended consequence of decreasing rather than increasing the overall level of compliance. To that end, API requests that the proposed rule be modified as follows:

§ 191.1 Scope.

- (a) This part prescribes requirements for the reporting of incidents, safety-related conditions, exceedances of maximum allowable operating pressure (MAOP), annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of gas pipeline facilities located in the United States or Puerto Rico, including pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331). ~~This part applies to offshore gathering lines and to onshore gathering lines, whether designated as “regulated onshore gathering lines” or not (as determined in § 192.8 of this chapter).~~
- (b) * * *
- (2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 C.F.R. 190.9; ~~or~~
- (3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator; or.
- (4) ~~Sections 191.22(b) and 191.29 do not apply to Onshore gathering of gas—~~
 - (i) Through a pipeline that operates at less than 0 psig (0 kPa);
 - (ii) Through an onshore pipeline that is not a regulated onshore gathering line (as determined in § 192.8 of this chapter), except for the requirements in §§ 191.5, 191.7(a), (d), 191.15, 191.17, 192.21, 191.22(a), and (d); and
 - (iii) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612.

By submitting to these modifications, changes are also needed to the Natural and Other Gas Transmission and Gathering Pipeline Systems Annual Report Form (F7100.2-1), and API recommends the Agency only collect Section A. Operators would also provide the diameter of the regulated gathering lines. This data would provide support for future rulemakings. A better approach for the Agency would be to have an annual report form developed specifically for gathering, allowing for appropriate information on regulated and unregulated gathering to be requested. Additionally, while it is difficult to provide substantive comments given concurrent regulatory proceedings, API asks that PHMSA coordinate with the ongoing information collection request regarding edits to the Natural and Other Gas Transmission and Gathering

Pipeline Systems Incident Report Form (F7100.2) and include industry recommendations provided through that process.

Despite the ability to require the additional submission of data by operators, PHMSA is prohibited by statute from regulating certain gathering lines. As such, PHMSA may not require unregulated gathering line operators to comply otherwise inapplicable requirements of Part 192 in order to satisfy the proposed Part 191 reporting obligation. *49 U.S.C. § 60101(a)(21)(B)* (excluding from the definition of “transporting gas” the gathering of gas, except through regulated gathering lines, in a rural area outside a populated area designated by the Secretary as a non-rural area). Moreover, the implementation of the proposed rule would impose a more stringent compliance burden on operators of unregulated gathering lines, who would need to establish MAOP under all the requirements in §192.619, than operators of regulated gathering lines, who have the ability to establish MAOP under §192.619(c) solely on the basis of the highest actual operating pressure experienced during a five-year window.

Further, there is no justification provided in the NPRM or Preliminary RIA for requiring unregulated gathering line operators to comply with the MAOP exceedance reporting requirement. The burden of establishing MAOP for every segment of gathering line in the nation is nothing short of overwhelming—even if operators are allowed to use the five year period identified in §192.619(c). Segments of gathering lines can range from 50 feet to several miles in length. Given the number of potential segment MAOPs that would need to be established, documented, and then monitored on a basis necessary to meet the reporting requirements, the proposal is unreasonable. Unlike transmission operation, operating pressures on gathering lines are not monitored in real-time via supervisory control and data acquisition systems (SCADA). As a result, the information is difficult to collect and requires additional personnel. API also submits that the proposed reporting requirement is of marginal use in understanding the risk posed by gathering lines. There are better, more readily available data points that can offer key information about the risk posed and the measures necessary to prevent incidents. As with several other items, the additional cost to establish, document, monitor and report was not identified or included in the Preliminary RIA. API believes any benefit from the proposed requirement would be far exceeded by the cost.

Additionally, although the PSA provides PHMSA with the authority to require unregulated gathering line operators to provide “information pertinent to [PHMSA’s] ability to make a determination as to whether and to what extent to regulate gathering lines,” the proposal to indiscriminately extend all of the Part 191 reporting requirements exceeds this mandate. *49 U.S.C. § 60117(b)*. The NPRM and Preliminary RIA do not explain how or why all of the data sought in the Part 191 reports from unregulated gathering line operators is pertinent to the Agency’s determination of the need for future regulation, and the proposed application of certain provisions to those operators is completely impracticable.

PHMSA has inserted proposed provisions in the NPRM that would require complete documentation for the “life of a pipeline” throughout 49 C.F.R. Part 192, including but not limited to references at proposed 49 C.F.R. §192.67 (Materials); §192.127 (Pipeline design); §192.205 (Pipeline components); §192.227(c) (Welding qualification for transmission pipelines); §192.285(f) (Plastic pipe joining); §192.517 (Records); §192.607 (Material Documentation);

and, §192.624 (MAOP verification). In addition to operators now being required to keep these records for the life of the pipeline, some provisions necessitate companies with non-regulated gathering assets to determine and track information that is not explicitly required by the regulations. Further, the cost of maintaining these details, and the personnel required to do so, is of great consequence that has not adequately been evaluated through the Preliminary RIA. PHMSA has neither demonstrated a basis, nor established an expectation for such records in regard to gathering lines. To now require complete records *retroactively* is simply unrealistic and untenable for any pipeline, most especially gathering. API therefore requests that the NPRM be revised to remove these requirements.

As discussed throughout these comments, gathering lines operate much differently than transmission lines, and that fact needs to be considered when putting forward recordkeeping requirements, even if the requirements are only imposed *prospectively*. Gathering lines by their very nature are flexible systems designed to meet the changing needs of producers.

For all of these reasons, API asserts it is simply not feasible for the Agency to require MAOP determination for unregulated gathering lines and to implement the onerous evaluation and recordkeeping requirements being proposed.

E. Use of Non-Metallics Interpreted to be Disallowed

PHMSA should approve the appropriate use of non-metallic materials in gathering lines.

PHMSA's proposal to create a new, third-tier of gathering lines – Type A, Area 2, or Type C – is designed to ensure those larger-diameter pipelines operating at a maximum pressure of 20 percent or more of SMYS are subject to minimum safety requirements. PHMSA has identified these pipelines to be 8 inches and greater in diameter. However, the NPRM fails to acknowledge that there are certain types of gathering lines that will not be able to meet the requirements of Part 192, neither today nor in the future, when the repairs are required and the regulations cannot be met. The most prevalent examples are lines constructed using plastic, composite materials, or fiberglass (all referred to as “non-metallic” throughout this document). Given this proposal and PHMSA's lack of adopting by reference the most recent standards relating to non-metallic pipelines of this nature,¹⁹ the NPRM would indefinitely prohibit the use of non-metallic 8 inches or greater lines in gathering operations, as these types of lines either do not and cannot meet the requirements of Part 192, or they invoke design requirements that preclude their use in gathering lines with an MAOP above 125 psig. No operator, even if operating at pressures lower than 20 percent of SYMS, can operate with the possibility that non-metallic pipe will become subject to the requirements and require replacement.

API encourages PHMSA to clearly articulate through rulemaking that non-metallic lines, in the full range of dimensions, are allowed and that the pressure limits clearly reflect the pipe's capability as set forth in the standards set forth by ASTM and API standards. With this in mind, API suggests the following changes to §192.7:

¹⁹ The plastic industry has recently adopted three standards that establish the best practices for the design, manufacturing, installation, and maintenance of composite pipe for the purpose of transporting natural gas. *ASTM F-2619 (2013 Edition)*; *ASTM F-2805 (2016 Edition)*; and *API 15S (2016 Edition)*.

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

(b) American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, phone 202-682-8000, <http://api.org/>.

(11) API STD 15S “Spoolable Composite Pipe Systems” 1st Edition, 2016 Edition, (API STD 15S) IBR approved for §192.9.

(d) American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, Web site: <http://www.astm.org/>.

(16) ASTM F2619/F2619M-13 “Standard Specification for High-Density Polyethylene (PE) Line Pipe”, 2013 (ASTM F-2619) IBR approved for §192.9.

(17) ASTM F2805-11 “Standard Specification for Multilayer Thermoplastic And Flexible Steel Pipe And Connections”, 2016 (ASTM F-2805) IBR approved for §192.9.

API further requests that PHMSA recognize the benefits of plastic and composite lines and permit their use in repairing and rejuvenating steel gathering lines by repair or replacement of corrupted steel line sections and rejuvenation by pull-through of continuous (spooled or jointed) plastic or composite non-metallic lines inside of larger but corrupted steel or older plastic gathering lines. These wishes can be accomplished through appropriate exemptions for non-metallic lines.

Non-metallic lines up to 36 inches in diameter are widely used now and have been for decades in the gas gathering industry and may offer safer, more corrosion resistant service than steel lines in many applications. Currently, these lines are safely operated in many areas carrying linear and aromatic hydrocarbons, hydrogen sulfide (H₂S) and carbon dioxide (CO₂) gasses, and low pH highly saline brines. Industry’s goal is to preserve the ability to use the best materials in regards to design of specific applications using fit-for-purpose components for gathering lines, as well repairing of steel or non-metallic lines and for liners, protective outer shells, and rejuvenation of pipelines with insert strings of non-metallic lines. PHMSA should have a similar objective, ensuring operators have the opportunity to use the best materials available now and new ones developed in the future.

Despite the known benefits of non-metallics for gathering lines, as a result of this proposal with its unjustified design pressure limitations, previously installed non-metallic pipes will become functionally obsolete to the extent there is ever a need to repair them. For example, these lines will not be able to meet the corrosion requirements found in Subpart I, given that the very nature of the material used is not susceptible to corrosion. PHMSA’s proposal will immediately cause a ripple effect through the gathering industry, causing operators to cease the use of non-metallics in pipelines that are eight inches or greater and possibly smaller. This will impact operators, manufacturers and product suppliers, both directly and indirectly, including increasing the costs of gathering projects going forward simply due to the use of steel over the more economic and, by all measure, safe, non-metallic materials.

API therefore requests that PHMSA promulgate rules allowing approved use of non-metallic pipelines where appropriate.

F. Technical Drafting Errors Allow for Confusion; Justified Exemptions Not Provided

The NPRM contains drafting errors and inarticulate language that create significant uncertainty for the regulated community.

As drafted, it is difficult to determine the intent or applicability of several critical provisions in PHMSA's proposed regulations. The stated intent of the rule in the preamble as well as the Preliminary RIA and many provisions appear to directly contradict the actual scope and impact of the rule with respect to gathering lines, including those currently regulated and those PHMSA seeks to capture with the NPRM. In addition, numerous provisions found throughout the proposed rule would result in more stringent regulation of "Type A, Area 2" (API-Proposed "Type C") and "Type B" lines than is imposed upon Type A, Area 1 lines that operate at a higher SMYS. There are also a number of exemptions written into the proposed rule for particular types of gathering that are contradicted elsewhere in the NPRM through other cross-references.

To resolve these ambiguities, inconsistencies and contradictions, and for the reasons more fully explained below, API believes the following language would provide sufficient clarification:

§ 192.9 What requirements apply to gathering lines?

* * *

(b) Offshore lines. An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.13, 192.150, 192.319, 192.461(a)(4) and (f), 192.465(f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607 (including any references in other requirements), 192.619(e) (including any references in other requirements), 192.624 (including any references in other requirements), 192.631, 192.710, 192.711, 192.713 and in subpart O of this part.

(c) *Type A, Area 1 lines*. An operator of a Type A, Area 1 regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d)-(e), 192.150, 192.319(d), 192.461(a)(4) and (f), 192.465(f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607 (including any references in other requirements), 192.619(e)(including any references in other requirements), 192.624 (including any references in other requirements), 192.631, 192.710, 192.711, 192.713, and in subpart O of this part. However, an operator of a Type A, Area 1 regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) ~~Type A, Area 2~~ Type C and Type B lines. An operator of a ~~Type A, Area 2~~ Type C or Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d)-(e), 192.150, 192.319(d), 192.506, any references to §§ 192.607, 192.619(e), or 192.624, and 192.631;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines, except the requirements in §§ 192.461(a)(4) and (f), 192.465(f), 192.473(c), 192.478, 192.485(c), and 192.493;

* * *

(5) Establish the MAOP of the line under § 192.619(a)-(d), except for any references to §§ 192.607 or 192.624;

* * *

(8) For a ~~Type A Area 2~~ Type C regulated onshore gathering line only, ~~develop procedures, training, notifications, comply with the~~ emergency ~~plans and implement as described~~ requirements in § 192.615, except the requirements in § 192.615(a)(3).

Nothing in this subsection requires an operator of a Type C or Type B regulated onshore gathering line to comply with subparts N or O, or a requirement in subparts L or M of this part unless that requirement is specifically listed as applicable in paragraphs (3) to (8).

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

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

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

(a) * * *

(4) The pressure determined by the operator to be the maximum safe pressure after considering material records, ~~including material properties verified in accordance with § 192.607,~~ and the history of the segment, particularly known corrosion and the actual operating pressure.

* * *

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

(a) *Applicable locations.* The operator of an onshore transmission 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): [...]

Accordingly, API requests that PHMSA insert a new provision under §192.631(a), as follows:

§ 192.631 Control room management.

- (a) General. (1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section, except that for each control room where an operator's activities are limited to ~~either or both of:~~
 - (i) Distribution with less than 250,000 services; ~~or~~
 - (ii) Gathering lines; or
 - (iii) Transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (d) (regarding fatigue), (i) (regarding compliance validation), and (j) (regarding compliance and deviations) of this section.

Implementing these revisions will rectify both inconsistencies and what appear to be errors in the proposed rule, and resolve additional points of confusion.

1. Clarification of Applicability of 49 C.F.R. § 192.13

Section 192.13 of 49 C.F.R. Part 192 is the foundation that establishes which requirements regulated pipelines are subject to under the regulations. As currently drafted, the Type A, Area 1 gathering lines that operate at higher SMYS are exempt from 49 C.F.R. § 192.13, whereas the Type A, Area 2, or API's Type C, and Type B gathering lines that operate at lower pressures are subject to the requirements. API believes that this exemption for Type A, Area 1 gathering lines must be in error, not just in light of the differences in the types of the lines, but because the subsection provides a grace period of one year from the effective date of the rule change for those pipelines that are not previously regulated but become regulated as a result of the changes. API would assume that PHMSA intends for *all* operators impacted by the rule to benefit from such a grace period.

At the same time, not providing a corollary exemption for proposed provisions 49 C.F.R. §192.13(d) and (e) for Type A, Area 2 (API-Proposed "Type C") and Type B gathering lines is simply untenable for *any* gathering operator. There is no reasonable basis to exempt these lines from the requirement where other gathering lines operating at a maximum operating pressure of more than 20 percent of SMYS are exempt. Additionally, both subsections (d) and (e) of 49 C.F.R. §192.13 relate to areas of the regulations to which Type A, Area 2, (API's suggested Type C), and Type B are not subject, such as those of material verification and management of change. For these reasons, API requests that these inconsistencies that appear to be simply technical drafting errors be resolved.

PHMSA also held three webinars after the publication of the NPRM. In two of these events, verbal clarification was given regarding the confusion in §192.13. Although API is appreciative of PHMSA's statements that it does not intend to apply §192.607, §192.624, or §192.506 to both Type A, Area 1, or Type A, Area 2 (API's Type C) regulated gathering lines, it is important to reiterate through formal comment the discrepancies that currently exist in the NPRM.

2. Parity between Type A, Area 1 and Type A, Area 2 (API-Proposed "Type C") and Type B Gathering Lines

The NPRM proposes to include certain exceptions from new provisions for Type A, Area 1 lines, but fails to include similar exemptions for those pipelines operating at a lower pressure and less than 20 percent of SMYS that are classified as Type A, Area 2 (API-Proposed "Type C") and Type B lines. As a result, the requirements for higher pressure gathering lines are actually less stringent than the requirements for low pressure ones. The provisions at issue include the following:

- Passage of internal inspection devices (§192.150)
- Corrosion control requirements (§192.319)²⁰
- Inspection of coating after backfilling (§192.461(f))
- External corrosion-test station "low" reading remediation (§192.465(f))
- External corrosion-interference with currents (§192.473(c))

²⁰ See additional note relating to §192.319 as stated exemption should only reference §192.319(d).

- Internal corrosion control-onshore transmission monitoring and mitigation (§192.478)

As set forth in the suggested revised text above, API asks that PHMSA remedy this disparate treatment by aligning the list of exceptions among all regulated gathering lines in the final rule.

Similarly, modifications to 49 C.F.R. § 192.319 are also needed. As currently worded, 49 C.F.R. § 192.9(c) fails to include a specific reference to subsection (d) of 49 C.F.R. Part 192 when exempting Type A, Area 1 lines.²¹ As a result, Type A, Area 1 lines are exempt from the *entirety* of §192.319, relating to the installation of pipe in a ditch, rather than only the newly proposed subsection “(d).” API doubts PHMSA intended this exception, and this error can be readily addressed by adding reference to subsection “(d)” after reference to §192.319, as set forth in API’s proposed revisions above.

3. Clarify and Preserve Stated Exemptions

Throughout the proposed rules, numerous cross references create inconsistencies by subjecting operators to one requirement based on the applicability of another requirement, including instances where operators would be required to comply with provisions that they are otherwise expressly exempted from elsewhere in the regulations. API has attempted to make these clear in the proposed revision above.

For example, with respect to verification of pipeline material under 49 C.F.R. §192.607, PHMSA has proposed that pipelines installed prior to the enactment of the rule that do not have “reliable, traceable, verifiable and complete” records (which is not defined) must determine the properties of the pipe and related appurtenances. While the requirement is technically only applicable to Type A, Area 1 lines, both 49 C.F.R. §192.485 and §192.619 cross-reference 49 C.F.R. §192.607 and could be interpreted to subject Type A, Area 2, or API’s Type C, and Type B lines to those requirements as well. Companies operating gathering lines have never been required to maintain all records. Gathering lines are regulated differently than transmission lines as determined by several key, historical rulemakings. An expectation that these records will ever be “complete” is simply unrealistic. API assumes PHMSA did not intend to subject regulated gathering lines to these requirements, given the intent of the rule and the Preliminary RIA, but the proposed rule requires clarification. As reflected in the suggested language above, API requests that explicit exemptions from 49 C.F.R. § 192.607 be added for all regulated gathering operators to eliminate any uncertainty in that regard.

Similarly, as currently proposed, Type A, Area 1 gathering operators are required to follow the requirements of transmission operators with certain exemptions including from permanent field repair of imperfections and damages under 49 C.F.R. §192.713. Despite the stated exemption, several references in 49 C.F.R. §192.711 and §192.719 – which are applicable to Type A, Area 1 lines – also reference §192.713. As a result, the rule can be interpreted to require Type A, Area 1 gathering lines to adhere to the requirements of §192.713, regardless of the stated exemption. Likewise, the proposal can be read to capture some Type B lines, which are also subject to the requirements due to references in §192.624. While API has already suggested that Type B lines should be clearly exempted from this subsection, if there is no express provision to the contrary,

²¹ *Id.* Pursuant to preceding discussion, “Type A, Area 1” lines would be labeled “Type A” lines in the final rule.

they could very well be required to make repairs per the requirements of §192.713 due to the cross-reference with the subsection found in §192.624.

Lastly, under the NPRM, operators of regulated gathering lines must establish MAOP in accordance with 49 C.F.R. §192.619. The statements laid out in the NPRM, Preliminary RIA, and Congressional mandate that prompted PHMSA to issue 49 C.F.R. §192.624 confirm that the proposed MAOP verification requirements are only applicable to gas transmission lines, not gas gathering lines. PHMSA is proposing to amend §192.619 to add a new subsection (e) to the existing requirements, however, *NPRM at 20833*, which would require operators of gas transmission lines—which includes Type A, Area 1 and could be read to include Type A, Area 2 (API-Proposed “Type C”) and Type B—that meet criteria in §192.624 to comply with an elaborate set of MAOP verification. *Id.*

To be consistent with the intent of the NPRM, the supporting data in the Preliminary RIA, the Congressional mandate, and to avoid any uncertainty, API requests that PHMSA modify the regulation proposed in the NPRM – as reflected in the above suggested revisions – to clearly state that regulated gathering operators only need to comply with §192.619(a)-(d), which include the five-year look-back period, in establishing an MAOP. In addition, for consistency and clarity, the existing chart currently referenced in the rule that outlines the look-back period should be included and amended to clarify that those pipes pulled into the rule as a result of the proposed changes may also use this methodology for establishing their MAOP.

Again, PHMSA clarified it was not its intent to subject gathering lines to expanded sections §192.607 and §192.619(e) and new §192.624 during the webinars hosted on June 28 and 29, 2016. API’s proposed revisions are consistent with these recent explanations.

4. Applicability of CRM and OQ to Expanded Regulation of Gathering Lines

The NPRM does not discuss the applicability of existing control room management (CRM) regulations to gathering lines under the expanded regulation proposed in the NPRM. The existing CRM rules exempt gas distribution systems with less than 250,000 service connections (§192.631(a)(1)). A similar exemption should be explicitly stated for all gathering lines for the same reasons: distribution lines and gathering lines are “both smaller and simpler [than transmission lines]. They pose less complexity.” *Final Rule, Control Room Management, 74 Fed. Reg. 63310, 63314 (Dec. 3, 2009)*. In addition, gathering lines are similar to distribution lines in that they rarely have controllers, control rooms, or SCADA systems comparable to transmission lines. The SCADA systems that are used typically monitor the flow of production activities, which is not jurisdictional to PHMSA. They are remotely accessed or set up to send an alarm to remote operators that do not serve the same role as a controller. Further, these SCADA systems do not offer complex leak detection tools. With no controller, limited ability to control the pipeline, and no formal leak detection system in place, gathering operators should be exempted from such a requirement. Similarly, the Agency’s operator qualification (OQ) rules that relate to CRM should exempt gathering lines for the reasons just noted.

Accordingly, API requests that PHMSA insert a new provision under §192.631(a), as follows:

§ 192.631 Control room management.

- (a) General. (1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section, except that for each control room where an operator's activities are limited to either or both of:
 - (i) Distribution with less than 250,000 services, or
 - (ii) Gathering lines, or**
 - (iii)** Transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (d) (regarding fatigue), (i) (regarding compliance validation), and (j) (regarding compliance and deviations) of this section.

In addition to the aforementioned proposed change in regulatory text, API asks that PHMSA coordinate the other ongoing rulemaking affecting OQ requirements. API is concerned PHMSA has yet to determine how this rulemaking interrelates with the NPRM issued on July 10th, 2015, titled “Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Proposed Changes.” *NPRM, Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Proposed Changes, 80 Fed. Reg. 39916, 39920 (Jul. 10, 2015)* Before a Final Rule is issued for either proceeding, the Agency should ensure coordination between the two NPRMs.

5. Material Verification Should be Inapplicable to Gathering Lines

As set forth above, API is concerned that if the NPRM is adopted as proposed, gathering lines will be subjected to material verification requirements due to several apparently inadvertent cross-references found within 49 C.F.R. §192.13 and §192.624. Even if these incorrect cross-references are addressed by PHMSA in a final rule, API nevertheless remains concerned that gathering lines will be subjected to the proposed material verification requirements. Specifically, Type 1, Area 1 gathering lines operating at maximum pressures that exceed 30 percent of SMYS will be subject to the extensive requirements found in newly proposed 49 C.F.R. §192.607. Given the wording of both the preamble to the NPRM and the accompanying Preliminary RIA, it does not appear that this was PHMSA’s intention. To resolve this inconsistency, API suggests that an exemption be provided for all gathering lines by adding (1) a reference in 49 C.F.R. §192.9(c) for Type A, Area 1 gathering lines; and (2) a subsection (d)(2) for Type A, Area 2 (API-proposed “Type C”) and Type B gathering lines.

As further support for this proposed clarification, API notes that material verification was never intended as a gathering line requirement; the provisions of the PSA, as well as outstanding NTSB recommendations, are all focused on transmission pipelines. PHMSA has never established a requirement for gathering operators to keep all records relating to a gathering line from the point of design and construction. As a result, and as explained elsewhere in these comments, gathering operators will likely not have the undefined “reliable, traceable, verifiable, and complete records” that PHMSA mandates in the NPRM yet does not define. As discussed previously, gathering lines and their applicability to regulation are different than transmission lines. In addition, since operators have never had an obligation to retain these records, the records have not always accompanied assets as they have been sold, purchased, or otherwise acquired. An expectation that these records will ever be “complete” for gathering lines is simply unrealistic.

Finally, API notes that a material verification requirement for *any* type of pipeline does little to improve the actual safety of a system. Requiring operators to remove isolated sections or coupons of pipe in order for operators to determine the exact chemical and material composition of the pipe would not yield any information to determine or confirm the integrity of the pipeline as a whole. To the contrary, it would likely introduce unnecessary risk into the system by creating additional welding, disruption in coating and unnecessary work that ultimately may result in additional inconsistencies.

As mentioned earlier, API is grateful for PHMSA's webinar presentations that detail the intent of the Agency not to apply the MAOP verification requirements to gathering lines and believes the foregoing analysis supports that determination.

6. *Hydrostatic Spike Test Requirements Are Unnecessary for Gathering Lines*

PHMSA has proposed a new subsection requiring the operators of pipelines operating at pressures greater than 30 percent of SMYS to be hydrostatically spike-tested when "integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment". This proposal, as drafted, does not include an exemption for gathering lines.

PHMSA has offered no justification for the applicability of such a provision to regulated gathering lines, nor is an analysis of such a provision included in the Preliminary RIA. Further, gathering lines are not subject to integrity management requirements under Subpart O. Despite all these facts, the provision, as drafted, could be interpreted to impact gathering lines as virtually any pipeline could be considered to have "integrity threats" as outlined in the proposal, since there is no definition offered for this broad description.

For this reason, an exemption from §192.506 should be provided for all regulated gathering lines. API suggests that a specific reference to §192.506 is added to each of the provisions in §192.9(c) and (d).

Finally, as mentioned earlier, PHMSA did state in the webinars hosted in late June 2016 that they did not intend to subject gathering lines to expanded §192.506. API still wants to communicate through formal comment the fact that the NPRM did not clearly speak to this verbal statement.

7. *Integrity Management Exemptions Should be Explicit*

Several proposals contained within the NPRM related to integrity management requirements contained within Subpart O. These include references to §192.493, §192.710, §192.711 and §192.713. While PHMSA has provided exemptions for gathering lines for some, not all have been referenced as exemptions in §192.9(c) and (d).

API suggests that explicit exemptions be provided for regulated gathering lines. Further, API asks each of these provisions should be moved to Subpart O as they are more appropriately located there to insure the clarity of the provisions and applicability.

G. Request for Associate Administrator Approval is Excessive

The Agency's implementation of a new approval process involving the Associate Administrator of PHMSA will demand unnecessary operator resources.

In over a half-dozen provisions, the NPRM proposes to institute for the first time in the PHMSA pipeline regulations an approval process by the Associate Administrator of PHMSA. Specifically, the NPRM would require Associate Administrator approval in 49 C.F.R. §191.25(a), §192.3 (“Gathering line (onshore)”), §192.506(g), §192.607(d)(6), §192.624(b)(4), §192.624(c)(3)(iii)(a), §192.624 (c)(6), §192.624(e), and §192.921(a)(7). There is no reference in any other section of the 49 C.F.R. Parts 190-199 regulations for the Associate Administrator to make such decisions. Although there is one reference in the newly proposed regulations to the process set forth in 49 C.F.R. §190.9, which relates to petitions of finding or approval, that provision does not involve the Associate Administrator, unless he or she is identified as the designee of the Administrator. Further, this new process also fails to involve those other federal (e.g., OSHA) and state agencies responsible for the enforcement of safety standards, which is more appropriate for such systems.

In conformance with API's proposed changes to the transmission regulations, API suggests that PHMSA delete any reference to obtaining a “no objection letter” from the PHMSA Associate Administrator.

For example, an operator seeking to designate an endpoint downstream of the first processing plant, as it is proposed in the rule, would now be required to secure approval from the Associate Administrator of Pipeline Safety, a departure from the current requirement of simply demonstrating through sound engineering principals that the line extends to a downstream plant. These changes would place a higher burden on gathering operators in two ways: time and cost. Not only will operators have to spend more time and effort in preparing information for such an application and inevitable follow up, but the time required to secure such approval has the real ability to influence projects, as there is no limit on how long the Administrator has to make a final determination. Ultimately, operators could be forced to operate a line as a transmission line while waiting for such approval, significantly impacting the economics since additional equipment and design will be required.

H. Implementation Compliance Deadlines Should be Suitable

Industry needs reasonable deadlines to comply with the new regulations.

PHMSA is also proposing to create a new evaluation and recordkeeping requirement at 49 C.F.R. §192.8(a) that would apply to all operators of production and gathering lines. Specifically, the NPRM states that operators of existing pipeline systems have six months to establish the beginning and endpoints of each gathering line and must maintain records documenting the results of that evaluation. *NPRM at 20827*. Operators of new gathering lines would be required to do the same before a line is placed into service and must also maintain records documenting the results of that evaluation. *Id.*

PHMSA continues to exempt some gathering lines in rural areas from jurisdiction and, as a result, those lines are not subject to the requirements of 49 C.F.R. Part 192. *NPRM at 20828*. In keeping with that, the proposed requirement in 49 C.F.R. §192.8(b) would only apply to operators of regulated gathering lines. In contrast, however, the Agency proposes to apply 49 C.F.R. §192.8(a) to operators of all gathering lines, whether regulated or not.

For these reasons and as more fully explained below, API requests that the following modifications be made to the proposed text of §192.8 to provide adequate time for those who must evaluate and document the beginning and endpoints of gathering as well as the timing by which operators are expected to implement the proposed changes:

§ 192.8 How are onshore gathering lines and regulated onshore gathering lines determined?

- (a) Each operator of a regulated gathering line must determine and maintain records documenting the beginning and endpoints using the definitions of onshore production facility (or onshore production operation), gas processing facility, gas treatment facility, and onshore gathering line as defined in § 192.3 by the compliance timetables in the below table. ~~by [date 6 months after effective date of the final rule] or before the pipeline is placed into operation, whichever is later.~~
- ~~(b) Each operator must determine and maintain records documenting the beginning and endpoints of each regulated onshore gathering line it operates as determined in § 192.8(e) by [date 6 months after effective date of the final rule] or before the pipeline is placed into operation, whichever is later.~~

These deadlines have been outlined in the following table, which should be included in the final rule in a similar nature to that of the 2006 rulemaking under §192.9(e)(2):

Requirements for Existing Pipelines Subject to Revised Rules for Type C or Type B Requirements	Compliance deadline
If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines	1 year
Documenting beginning and endpoints of gathering	2-years from enactment (ensure 2 summers)
If the pipeline is metallic, control corrosion according to requirements of Subpart I of this part applicable to transmission lines;	5-years
Carry out a damage prevention program under §192.614	2-years from enactment (ensure 2 summers)
For Type C regulated on shore gathering line only, develop procedures, training, notifications, emergency plans and implement as described in §192.615.	2-years from enactment
Establish a public education program under §192.616	2-years from enactment
Establish MAOP under §192.619(a)-(d)	3-years from enactment
Promptly repair hazardous leaks that are discovered in accordance with §192.703(c)	3-years from enactment
Conduct leakage surveys in accordance with §192.706 using leak detection equipment	3-years from enactment
Install and maintain line markers under §192.707	2-years from enactment (ensure 2 summers)
Other provisions as required by paragraph (c) of this section for Type A, Area 1 lines	10-years from enactment

Requiring operators to conduct a separate evaluation of newly regulated onshore gas gathering lines within six months of the final rule is unrealistic. From the time the rule is issued there is an unreasonably short time period for operators to learn the rule, train the necessary personnel, and begin to look at each configuration one by one on many miles of pipeline and related facilities.

As a point of comparison, note that the March 2006 Final Rule did not impose any deadline for determining whether pipelines met the current definition of an onshore gas gathering line at 49 C.F.R. §192.8, and PHMSA has not provided any justification for imposing that new requirement in this proceeding. API would suggest that only operators subject to the requirements of 49 C.F.R. Part 192 should be required to document the beginning and endpoints of gathering in accordance with the definitions found in §192.3. However, operators should only be required to designate the endpoint of gathering if it is operated by that entity. In some cases, producers or gatherers will not know where the gathering endpoint is as it may be beyond their span of control or knowledge. This is the approach PHMSA follows under the current rules, and there is no need to deviate from the practice in this proceeding.

Finally, requiring operators to determine whether a pipeline qualifies as a regulated gathering line within the same six months of the final rule is also unrealistic. Unlike transmission lines, gathering lines are often shorter segments of pipe, dispersed across a regional area in a non-linear fashion, and configured in various ways to achieve greater efficiencies to meet the needs of producers, which means they often do not run in continuous segments.

While discussing compliance deadlines, API wanted to again highlight the extended deadline needed should PHMSA propose any restriction on the use of the incidental gathering line designation requiring operators to reclassify the lines as transmission. As mentioned earlier, the proposed rule must be modified to include a 5-year compliance deadline to the extent that incidental gathering lines are reclassified as fully-regulated transmission lines.

The NPRM provides only a two-year compliance deadline from the effective date of the final rule for gathering lines that become subject to the requirements under proposed 49 C.F.R. §192.9(e). Because of the expansiveness of proposed changes to the definition of gathering and related regulatory requirements, if the rule is adopted as proposed, it is likely that a significant number of gathering lines will become subject to one of the three identified types of gathering: Type A, Area 1; Type A, Area 2 (API-Proposed “Type C”) and Type B. Due to the significant undertaking required of operators in order to ensure compliance of these assets, API is requesting a phased-in approach for those regulatory deadlines for the new requirements.

Although this requested approach is similar to that of the regulation of gathering that was finalized in 2006, the number of gathering lines that became regulated in 2006 is a small fraction of those that would become regulated as a result of the proposed changes in the NPRM. Despite this fact, PHMSA does not offer any justification in the NPRM or Preliminary RIA for providing a comparatively shorter compliance deadline. Operators of existing gathering lines that become regulated gathering lines or subject to additional requirements as a result of the rulemaking for any reason, must nevertheless be provided with additional time to achieve compliance with the proposed rules, and API proposes that a:

- *two-year initial compliance deadline* be provided for the damage prevention, public awareness, line marker, and emergency response requirements, and establishing MAOP;
- *three-year initial compliance deadline* should be provided for the leak detection and repair requirements;
- *five-year compliance deadline* should be provided for the corrosion control requirements.

I. Emergency Plan Requirement is Unclear

Similar to other provisions, more clarification is needed on the Agency’s expectations for emergency response and Type A, Area 2, or API’s Type C, gathering lines.

PHMSA has proposed to extend emergency response related activities to only Type A, Area 2 gathering lines. This provision at 49 C.F.R. §192.9(d)(8) states the following: “For Type A, Area 2 regulated on shore gathering line only, develop procedures, training, notifications, emergency plans and implement as described in §192.615.” It is based on the GAO report issued in 2014 that recommended that PHMSA seek to address “larger-diameter, higher pressure” lines, including requiring them to engage in additional emergency response preparedness exercises.

This reference deviates from the requirements included in referenced 49 C.F.R. §192.615, however, raising uncertainty with regard to PHMSA's intent and the actual requirements that operators will have to implement to fulfill the requirement. Accordingly, API requests that the following revision be made to 49 C.F.R. §192.9(d)(8) to resolve the confusion:

§ 192.9 * * *

(d) * * *

- (8) For a ~~Type A Area 2~~ **Type C** regulated onshore gathering line only, ~~develop procedures, training, notifications, comply with the~~ emergency ~~plans and implement as described requirements~~ in § 192.615, except the requirements in § 192.615(a)(3).

This change should clarify PHMSA's apparent intent for operators of Type A, Area 2 (API-Proposed "Type C") gathering systems to implement all components of §192.615 instead of citing concepts that are not addressed in that provision. Alternatively, if operators are only going to be held responsible for specific, individual components of §192.615 then those subsections should be clearly and accurately referenced.

J. Dependence on Existing Transmission Line Regulation Affords Obscurity; New Subpart for Regulated Gathering Lines Could be Developed for Simplicity

As proposed, the NPRM entangles transmission line and gathering line regulations causing extreme confusion and the need for clarity in 49 C.F.R. Part 192.

PHMSA states in both the preamble of the NPRM as well as the Preliminary RIA that the proposal seeks only to expand regulatory requirements to a new classification of previously unregulated gathering lines. While this may be the intent, the proposed changes have a much greater impact than projected by PHMSA.

First, gathering regulations are based on the transmission requirements, and any time a change is made to the transmission requirements that change extends to gathering. Second, while it appears that PHMSA added the word "transmission" in a number of proposed sections to limit the application of certain provisions to transmission pipelines, the result has been the exact opposite. As proposed, 49 C.F.R. § 192.9(c) states that "An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines..." Additionally, there is a similar statement in proposed 49 C.F.R. § 192.9(d) relating to Type A, Area 2 and Type B gathering lines. The result of these statements is to extend these new provisions to gathering as well as transmission pipeline operators, in direct contradiction of statements throughout the preamble and Preliminary RIA.

For these reasons, API respectfully requests that PHMSA take several specific, calculated steps to decouple the existing and future regulatory requirements for regulated gathering lines from the requirements for transmission. This can be achieved quickly and efficiently by creating a new subpart of 192, such as a new "Subpart," that addresses "Regulated Gathering" separately. If done cooperatively with industry and other appropriate stakeholders, the subpart could either be

completed in conjunction with the existing proposed rule or initiated through a separate, future rulemaking.

A separate subpart will streamline the regulations for operators for compliance purposes and for the Agency and its inspectors for enforcement purposes. That consistency will ultimately promote a uniform application of the rules, a higher level of compliance, and provide for enactment of the provisions related to transmission lines in the NPRM. If PHMSA decides against the separate subpart and proceeds on its current course of using existing regulatory structure that has a focus on transmission, the agency is risking future litigation, given its failure to provide clear and meaningful analysis to support its proposals and the significant unintended consequences of the presence of multiple inconsistencies throughout the NPRM.

III. Gas Transmission

A. Material Documentation and MAOP Verification Should be Withdrawn

A Testing-Based Approach Is Better Suited to Congressional Mandates and NTSB Recommendations

The NPRM details PHMSA's proposal for fulfilling the mandate in Section 23 of the 2011 PSA amendments and various NTSB recommendations concerning confirmation of MAOP and related testing of older or previously untested pipelines. Specifically, PHMSA proposes a new §192.67 to require operators of transmission pipelines to acquire and retain for the life of pipeline certain original pipe manufacturing records. *NPRM at 20828*. Most notably, a new §192.607 is proposed to require operators to have "reliable, traceable, verifiable and complete" records (a standard which is not defined in the regulations) of specific attributes of their system and to govern the process of material verification where such records are not available. *NPRM at 20831*. Lastly, PHMSA proposes a new §192.624 to require MAOP verification for certain pipeline segments through one of several methods specified in the proposed rule. *Id. at 20833-34*.

The proposals for §192.67, §192.607 and §192.624, taken together, constitute PHMSA's proposed requirements for what has previously been referred to as the Integrity Verification Process (IVP). PHMSA initially suggested IVP in response to Section 23 of the PSA of 2011 and NTSB Safety Recommendations P-11-14, P-11-15, and P-11-17, all of which were issued in response to the San Bruno incident. *See 49 U.S.C. § 60139(d)(1)* (requiring PHMSA to require by regulation tests to confirm the material strength of "previously untested" natural gas transmission pipelines located in high consequence areas and operating at a pressure greater than 30% SMYS); *NTSB Recommendation P-11-15* (recommending revision of Part 192 to provide that manufacturing and construction related defects can only be considered stable if a pipeline has been subjected to a post-construction hydrostatic test of at least 1.25 times MAOP). IVP was subsequently the subject of an August 2013 public workshop.²²

API participated in the development of this regulatory process, most recently by submitting comments on the draft IVP published by PHMSA in advance of the 2013 workshop. API's 2013

²² See Docket PHMSA-2013-0119, available at <https://www.regulations.gov/#!docketDetail;D=PHMSA-2013-0119>.

comments focused on the breadth of the proposal in relation to the Agency's congressional mandate as well as the steps that are reasonably necessary for operators to safely manage their pipelines. These same concerns persist, in large part, with the issuance of the NPRM proposals. Yet PHMSA mentions this workshop in the preamble to this NPRM only briefly, stating that the comments received were considered, but failing to further discuss or analyze those comments.

It is clear from both the congressional mandate and the relevant NTSB recommendations that the primary underlying concern is the pressure testing of pipelines. These directives contemplate that operators will verify adequate records and documentation. The primary intent is not necessarily to have the records, but to confirm MAOP. The problem of insufficient records to substantiate MAOP can be remedied by pressure testing. PHMSA's 2011 and 2012 advisories endorsed such an approach.²³

PHMSA's proposed regulations do not take into account both the objective and the reasoning behind the statutory mandate and NTSB recommendations, particularly §192.67, §192.607 and §192.624. The Agency's proposals do not accomplish their primary purpose, and are beyond the scope of the goals mandated by Congress and recommended by the NTSB. As a result, they should be withdrawn from this rulemaking in their present form. API strongly encourages PHMSA to withdraw proposed §192.607 and §192.624 in favor of an alternative approach that is consistent with the intent of both Congress and the NTSB, which was for PHMSA to formulate a straightforward, complete, and reasonable means of confirming MAOP. These same sentiments were expressed to PHMSA at a recent Advisory Committee meeting with comments to the effect that the proposed rules are so complex, burdensome, prescriptive and onerous that the rule actually becomes almost impossible, and that honest and open dialogue is called for so that a rule that is understandable, practicable, achievable and addresses the more significant issues can be enacted. *Comments of J. Andrew Drake, Spectra Energy Transmission, Transcript, GPAC/LPAC Joint Meeting (Jun. 2, 2016), at pp. 360-61.*

API further believes that its own proposed straightforward approach, which directly responds to the relevant congressional mandates and NTSB recommendations, would have had a significantly greater chance of identifying the pipe pup judged to have been substandard and deficient and that initiated the San Bruno incident. It is unclear whether all of the options proposed by PHMSA are achievable in practice. Further, the sampling-based options proposed by PHMSA in §192.607 and subsequently invoked in §192.624 and several other sections of the NPRM, even assuming that they could be implemented in practical terms, would not identify substandard pipe. The approach outlined below would more definitively address the underlying issue and achieves the goal of preventing the reoccurrence of an event like the tragic San Bruno incident.

1. Material Records Requirements are Unachievable

²³ *Advisory Bulletin, 77. Fed. Reg. 26822, 26832 (May 7, 2012)* ("PHMSA is now considering whether these pipelines should be pressure tested to verify continued safe MAOP"); *Advisory Bulletin, 76 Fed. Reg. 1504, 1505 (Jan. 10, 2011)* ("There are several methods available for establishing MAOP or MOP. A hydrostatic pressure test that stresses the pipe to a designated percentage of the desired MAOP or MOP without failure is generally the most effective method.").

The proposed §192.67, the initial documentation requirement in this process, would require operators to “acquire and retain for the life of the pipeline” certain original steel pipe manufacturing records. *NPRM at 20828*. The language of this requirement, which is proposed to be a regulation in the non-retroactive Subpart B (“Materials”), appears to apply retroactively. It states: “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.” *Id.*

This is both inappropriate, and in many cases, unachievable. It requires an operator to acquire and retain original records without specifying dates by which operators would be required to acquire them, and the phrase “at the time the pipe was manufactured” clearly suggests retroactivity. Many pipe mills that have historically fabricated pipe for operators in this country have, like many of the operators, undergone significant changes in ownership and corporate structure. Some no longer exist. Acquiring the required records, particularly when operators were not required to contemporaneously acquire and maintain them, is not possible in these cases.

Further, the proposal would require operators to acquire and retain records related to compliance with manufacturing specifications for “chemical composition” of pipe materials. *NPRM at 20828*. Such a requirement has no relationship to the establishment or confirmation of MAOP. Chemical composition is specified at the time of pipe production for consistency in mill control and pipe properties, weldability, avoidance of hot shortness, adequate toughness, and—more recently for thermomechanically processed steels—assurance of consistent properties throughout a coil or plate. Records documenting chemical composition are not necessary and frequently not helpful to determine the strength of the pipe. PHMSA does not provide any rationale as to how chemical composition would contribute in determining the MAOP or contributing to the verification of the integrity of a pipeline. Therefore, API, in agreement with AGA, recommends the following language for §192.607(d)(3)(iii).

§ 192.607(d)(3)(iii) Verification of pipeline material: Onshore steel transmission pipelines, Verification of material properties.

At each excavation, tests for material properties must determine the material properties that are necessary to calculate MAOP and for use in remaining strength calculations, which may include: diameter, wall thickness, [etc.].

API also recommends correcting the proposal with the modification shown below to clarify that the requirement is not intended to be, nor is it practicable to be, retroactive:

§ 192.67 Records: Materials.

For transmission pipe manufactured [or, in the alternative “ordered”] after (Insert date 6 months following the date of this Final Rule). 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.

2. *Material Documentation and Testing Requirements Exceed Congressional Mandates*

PHMSA proposes a new §192.607 to require operators to have “reliable, traceable, verifiable and complete” records (without defining that standard) of specific attributes of their system and to set forth a process of material verification where such records are not available. *NPRM at 20831*. The proposal would apply to segments of onshore steel gas transmission pipelines installed prior to the effective date of the final rule in a HCA or a Class 3 or 4 location that do not have “reliable, traceable, verifiable, and complete” (a standard that is undefined) records. *Id. (proposed §192.607(a))*. It requires operators to develop procedures for verifying the material properties of line pipe, valves, flanges, and components where material documentation is not available at both above-ground locations of line pipe and buried pipe segments that have been excavated and exposed. *Id. (proposed §192.607(d))*. Operators’ procedures would have to provide for tests, examinations, and assessments at all above-ground locations and all excavations associated with replacements or relocations of pipe segments that are removed from service. *Id. (proposed §192.607(d)(1) & (2))*. In addition, operators would be required to develop procedures for verification of pipe segments that are exposed during excavations associated with anomaly direct examinations, *in situ* evaluations, repairs, remediation, maintenance, or any other reason for which the pipe segment is exposed until completion of a prescribed minimum number of excavations. *Id. (proposed §192.607(d)(3))*.

For this latter category, the proposal specifies how operators must define populations of undocumented or inadequately documented pipeline segments; how operators must space assessments throughout a pipeline segment; the minimum number of excavations at which line pipe must be tested to verify pipeline material properties; what the tests for material properties must determine; the types and quantity of tests and tests locations; and requirements for additional excavations if test results identify line pipe with properties that are not consistent with expectations based on all available information for each population. *Id.* Operators would have to prepare a material documentation plan conforming to the requirements of the rule within 180 days of its effective date. *Id.*

These proposals go beyond what was contemplated by Congress in enacting PSA 2011, Section 23. As its title suggests, Section 23 (entitled “Maximum Allowable Operating Pressure”) is primarily intended to target confirmation of MAOP on high-consequence gas transmission pipelines. 49 U.S.C. § 60139(a)(2). PHMSA’s proposal, however, would require a comprehensive review and verification of a universe of “material documentation” that goes well beyond the physical and operational characteristics required to be verified under the statute and the documentation needed to confirm MAOP. API therefore suggests that PHMSA withdraw

this proposal and replace it with a proposal that is focused on confirming operating pressure limits through judicious use of hydrostatic testing and appropriate ILI tools.

a. Process Exceeds Statutory Mandate and NTSB Recommendations

PHMSA presented its initial flowchart for IVP, the blueprint for the proposed material documentation process, at the August 2013 workshop. In introducing the draft IVP, the Agency stated that the proposed process was based upon four principles:

1. Apply to higher risk locations - HCAs and moderate consequence areas (MCAs)
2. Screen segments for categories of concern (e.g., “Grandfathered” segments)
3. Assure adequate material and documentation
4. Perform assessments to establish MAOP

PHMSA, Pipeline Integrity Verification Process Workshop, Event Summary Report (Aug. 7, 2013), available at <https://www.regulations.gov/#/docketDetail;D=PHMSA-2013-0119>. These same principles were reiterated by PHMSA at the recent Technical Advisory Committee meetings and during at least one informational webinar.

These four principles go beyond the Section 23 of the 2011 PSA requirements and the NTSB recommendations. PHMSA explains this scope increase in its IVP frequently asked questions (FAQs). *PHMSA IVP FAQ #3* (explaining that “[t]he IVP is also addressing NTSB recommendations P-11-14, P-11-15, and P-11-17, which are broader than PSA Section 23 and apply to all gas transmission pipelines”). Even so, API understands these principles as steps in a process that, if applied reasonably and focused on the actual established goal, can provide a path to achieving the primary goals.

b. Testing-Based Approach Better Suited to Congressional Mandates and NTSB Recommendations

The PHMSA approach, as presented in the workshop and embodied in their proposed flowchart, is to provide an analogy or alternative to the requirements of §§192.619(a) and (b) to establish or confirm MAOP, which is the primary focus of the congressional mandates and NTSB concerns, as opposed to precise documentation of materials. Following the August 2013 workshop, the docket remained open for comments. Over 70 public comments were filed from over 40 different commenters. In this present rulemaking, PHMSA dismisses those comments with a cursory statement that it considered them. *NPRM at 20736*. There is no other indication of PHMSA’s consideration of those comments.

At least some of the comments posted to the IVP docket focused on the use of hydrostatic testing, which is consistent with the direction provided in the PSA and NTSB recommendations. One commenter concluded that a spike plus hold test can essentially cover everything that is needed to verify MAOP. This is not a unique proposal. Almost 50 years ago, the Pipeline Research Council International (PRCI) published a report detailing the importance of in-place hydrostatic testing to determine pipe strength. *See Study of Feasibility of Basing Natural Gas Pipeline Operating Pressure on Actual Yield Determined by Hydrostatic Test, PRCI Catalog L30050, A. R. Duffy, et al., Battelle Memorial Institute (Sep. 26, 1967)*. And as recently as June

2016 a PHMSA senior technical staff member reportedly testified that “A pressure test is the best way to check the integrity of the pipe.” *Fed Expert Takes on PG&E Over Fatal Explosion, Courthouse News Service (Jun. 22, 2016) (quoting Steven Nanney of PHMSA).*

Hydrostatic testing can be used to determine the in-place yield strength of a segment of pipeline, or, if not tested to actual yield, to determine the strength that may be taken as the minimum yield strength. Such a test demonstrates all pipe in the test section to have actual yield strength above the stress produced by the test. If this is done with a “spike test,” held for a few minutes, followed by a Subpart J test approximately 10% below the spike level, it effectively emulates the pipe mill testing to determine an SMYS plus field testing at 90% of that SMYS, thus allowing the pipeline to operate at 72% of the SMYS. In this case, in fact, all of the pipe and components are effectively interrogated regarding SMYS, which is typically not the case in a pipe mill, where SMYS is documented with flattened strap tensile tests that interrogate a few square inches of pipe out of perhaps 0.5 to 1.5 miles.

Post-test use of geometry ILI tools capable of measuring inside diameter with sufficient accuracy to detect yielding can further substantiate and perhaps quantify these results. Pre and posthydrostatic test geometry tool data can be compared to determine locations, if any, at which plastic deformation of the pipe occurred. If plastic deformation is observed, it can be quantified and correlated to the local pressure achieved during the test to determine how high up on the stress-strain curve the pipe reached during the test. Thus either actual yield strength or minimum yield strength for the segment may be established. API believes that such an approach is preferable for ensuring accurate characterization of pipe strength and confirming MAOP as compared to the elaborate, costly, and unnecessary material sampling, testing and documentation process PHMSA has proposed.

Two other sections of the current Part 192 regulations provide guidance for establishing or increasing MAOP on pipelines, even those not previously subject to the regulation under Part 192, and they follow a similar approach. These sections also rely heavily on the use of hydrostatic testing and do not explicitly require or rely upon extensive materials properties determinations.

First, the conversion to service requirements in §192.14, in existence and unchanged since 1977, allow an existing steel pipeline previously used in service not subject to Part 192 to be used subject to certain conditions that the operator must cover in a written plan, requiring:

- Review of the design, construction, operation and maintenance history, and, where sufficient historical records are not available, performance of appropriate tests to determine if the pipeline is in satisfactory condition for safe operation;
- Visual inspection of the pipeline ROW, all above ground segments and appropriately selected underground segments for physical defects and operating conditions that could impair the strength or tightness of the pipeline;
- Correction of all known unsafe defects and conditions;
- Subpart J pressure testing to substantiate the MAOP; and
- Recordkeeping for all of these actions.

49 C.F.R. § 192.14(a).²⁴

Second, Subpart K requirements for uprating to pressures at or above 30% of SMYS are similar. Section 192.555, which has remained unchanged since 1970, requires that operators, before increasing operating pressure above the previously established MAOP:

- Review the design, operating and maintenance history and previous testing of the segment to determine whether the uprating is safe and consistent with Part 192; and
- Make any repairs, replacements or alterations necessary for safe operation at the increased pressure.

49 C.F.R. § 192.555(b). After complying with these requirements, the MAOP may be increased to the highest pressure allowed under §192.619, using as the test pressure the highest pressure to which the segment was previously subjected either in a strength test or in operation, or the operator may test the line to new line test requirements. 49 C.F.R. §192.555(c); (d). There are other alternatives listed, but they are just that, alternatives, not absolute requirements.

Regardless of which method an operator uses, the key factor is pressure—the highest pressure to which the segment has been subjected, either in test or operation. The MAOP, per §192.619, is then set as a percentage of that pressure. By contrast, the proposed §192.607 appears to emphasize the “sidebar” materials process, rather than the establishment of appropriate pressure limits, which was one of the key purposes of the IVP.

c. Requiring Undefined “Reliable, Traceable, Verifiable, and Complete” Manufacturing Records Will Not Guarantee Improved Safety

As noted, PHMSA’s proposed section §192.607 would require operators to have certain manufacturing records that are “reliable, traceable, verifiable and complete,” without defining that standard. *NPRM at 20831 (proposed §192.607(c))*. As discussed in more detail below and in Section IV.B of these comments, PHMSA has not defined these terms, leaving considerable room for differing interpretations and inconsistent application and enforcement. If the plain meaning of these words is taken together, a case could be made that an operator with all of the available records to conform to the standards applicable at the time of manufacture and construction still would not meet the intent of this requirement.

Further, even satisfaction of the proposed and undefined “reliable, traceable, verifiable, and complete” records requirement does not necessarily guarantee improvements in safety, given the limited utility of such records. All material records, whether for pipe, fittings, flanges or valves, are based on either testing of samples or prototypes. Neither mechanical properties nor chemistries are determined on every piece, let alone every foot or inch. The two exceptions where testing or inspection is essentially complete are the mill hydrostatic test and the pipe weld

²⁴ Historically, the testing required under this section could be accomplished with a hydrostatic test. This is consistent with practices for new pipelines and with the use of hydrostatic testing as one of the primary assessment methods in integrity management programs. More recently, this testing may be supplemented with ILI to inspect for any deleterious corrosion or deformation anomalies.

seam non-destructive inspection. But the results of these tests and inspections are not factors in determining pipe strength or pipeline MAOP. In approximate numbers for line pipe, the requirements in API 5L result in determining a yield strength from a sample constituting a few linear inches out of perhaps a mile of pipe, or on a one or two pounds of steel out of 100 – 250 tons. When flattened straps are so tested, based on actual pipe mill statistics and yield strength distributions, the tail of the distribution that lies below the SMYS may range from much less than 1% to upwards of 10% of the pipe order. But these are for flattened straps tested in uniaxial tension, which is not the stress state or material condition in an operating pipeline. Taking more of these data (testing flattened straps and measuring chemistries from each quadrant of a pipe ring, as prescribed in § 192.607) does not make the data better, more reliable, more complete or more accurate. It does make it more expensive and entails more risk in all of the excavations that are prescribed to obtain it. In this case, the costs and safety risks inherent in performing such excavations outweigh the value of obtaining this type of data.

d. Alternative Approach to Material Documentation is Preferable

As opposed to gathering documentation on material properties that may only be of marginal value in assessing pipeline safety, an intelligently conducted hydrostatic test interrogates the entire pipeline—every inch of every joint. It does so by producing a state of stress that duplicates what the pipeline sees in service and is therefore an excellent test of the pipeline’s strength, a conclusion with which PHMSA apparently concurs. *See Fed Expert Takes on PG&E Over Fatal Explosion, Courthouse News Service (Jun. 22, 2016) (quoting testimony from Steven Nanney of PHMSA).* As noted above, such a test can be used to determine the minimum yield strength in the pipeline or a yield strength that is the lower bound for the pipeline. This can be confirmed and even quantified if needed by accompanying the hydrostatic test with geometry ILI before and after testing. Such an approach is more thorough, more exact, safer to conduct, more complete than extensive sample removal and testing, and it is totally verifiable. Irrespective of the definitions are applied to the currently undefined phrase “reliable, traceable, verifiable, and complete,” the testing-based approach advocated here comes much closer to meeting the intent of the standard than does the excavating, cutting and strap pulling approach.

Should PHMSA not accept the above proposal, API suggests that the following language be added to proposed §192.607(d):

§ 192.607(d) Verification of pipeline material: Onshore steel transmission pipelines, Verification of material properties.

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

In addition, API requests that PHMSA delete the reference in §192.607(d)(6) to the requirement to obtain a “no objection letter” from the PHMSA Associate Administrator. PHMSA enforcement and regulatory procedures do not provide for such letters and adding a new process that is not articulated in the rules or well-defined would cause even more confusion. Finally, as

outlined in Section II.C., API recommends that PHMSA include an express exception under existing §192.9(b) so that relevant exceptions for gathering pipelines are included.

Lastly, should PHMSA decide to retain proposed §192.607 in a final rule, API joins AGA in recommending inclusion of the following language in the regulation:

Until such time that the requirements within §192.607 have been met, or if the segment(s) under evaluation is not subject to the requirements under §192.607, supportable, sound engineering judgments may be used.

3. MAOP Verification and Testing Requirements are Unworkable

The NPRM sets forth PHMSA's proposal for fulfilling the 2011 PSA mandate regarding confirmation of MAOP on certain gas transmission pipelines. Under Section 23 of the 2011 PSA, for gas transmission lines in Class 3 and 4 locations and Class 1 and 2 locations in HCAs where records are insufficient to confirm MAOP, DOT must require MAOP confirmation "as expeditiously and as economically feasible" and to determine what actions are appropriate to maintain safety until MAOP is confirmed. 49 U.S.C. § 60139(c). For previously untested natural gas transmission pipelines located in HCAs and operating at greater than 30% SMYS, DOT is required to issue regulations for conducting tests to confirm material strength. 49 U.S.C. § 60139(d)(1). NTSB also recommended that PHMSA repeal the "grandfather" provision at 49 C.F.R. §192.619(c) and require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test. *NTSB Recommendation P-11-14 (Jan. 3, 2011)*.

PHMSA addresses the congressional mandates and NTSB recommendations by proposing a new §192.624 and related new and revised regulations. Section 192.624 would require MAOP verification where:

1. The segment has experienced a reportable in-service incident since its most recent successful Subpart J pressure test due to certain types of defects (i.e. those related to original manufacturing, construction, installation, or fabrication, or cracking-related defects) and the segment is located in an HCA, a Class 3 or 4 location, or an MCA, if the pipe segment can accommodate ILI;
2. Pressure test records necessary to establish MAOP for the segment are not reliable, traceable, verifiable, and complete and the pipeline is located in an HCA or a Class 3 or 4 location; or
3. MAOP was established in accordance with §192.619(c) (the "grandfather" provision) and the segment located in an HCA, a Class 3 or 4 location, or an MCA, if the pipe segment can accommodate ILI.

NPRM at 20833-20834.

For segments meeting any of the above conditions, operators would be required to confirm MAOP by using one of six prescribed methods, including pressure testing (which in some instances would require a spike tests conducted in conformity with proposed new §192.506), pressure reduction, engineering critical assessment, pipe replacement, or use of alternative

technology. *Id.* In addition, the proposal would require fracture mechanics modeling and fatigue analysis where the operator has reason to believe that any pipeline segment contains or may be susceptible to cracks or crack-like defects. *Id. at 20837.*

API appreciates PHMSA's efforts to promote safety on gas transmission lines by requiring confirmation of MAOP on certain high priority lines. As acknowledged by commenters on PHMSA's 2011 ANPRM and 2013 draft IVP, many companies have already begun work on meeting PSA-prescribed MAOP and testing requirements. API has concerns with several aspects of the proposal, however, that are similar in nature to those articulated above with respect to the proposed material verification requirements. In particular, API's concerns include the practicality and feasibility of the proposed methods for MAOP verification in §192.624(c) and the appropriateness of the proposed process for fracture mechanics modeling in §192.624(d).

These proposals are vague, burdensome, impractical and unsupported technically as to make them almost unworkable. API suggests that, short of adopting its recommendation, PHMSA withdraw these sections from the current rulemaking and convene a workshop of at least two days, inviting operators, technical experts, the NTSB and interested public to develop and explore these and other options, with at least half of the time being spent in facilitated topical break-out sessions, as opposed to a day of invited presentations. The methods developed should be realistic, achievable, understandable, and not result in more risk than they purport to mitigate. The methods proposed by PHMSA in the present rulemaking do not meet these criteria.

a. Proposed Methods for Confirming MAOP are Unworkable

The six proposed methods for confirming MAOP, when first considering them by their titles only, appear to provide a breadth of options and perhaps correspond to a large degree to the center or method boxes in the IVP flowchart. However, many of them veer into the unsupported and largely unnecessary testing requirements of §192.607 or the fracture mechanics requirements in §192.624(d), which also leads into the extensive excavation and testing of §192.607.

As discussed above with respect to API's an alternative approach to material documentation and testing, **the intent of the proposal—to confirm MAOP on certain lines—can be met by a judicious combination of hydrotesting and ILI.** API has concerns with each of the 6 methods outlined by PHMSA.

- Method 1 ("Pressure test") could be greatly improved by adopting the approach suggested above.
- Method 2 ("Pressure reduction") is relatively straightforward, but not practical in many cases.
- Method 3 ("Engineering critical assessment") contains so many undefined requirements that an operator attempting that option does not have a clear path to success or completion.
- Method 4 ("Pipe replacement") is also relatively straightforward, and has been used for years for pipe that is damaged or to maintain MAOP following Class location changes. It was the avoidance of this method—pipe replacements due to Class location changes—in favor of applying integrity management requirements that made up almost all of the cost

savings used in the cost-benefit analysis of the integrity management regulations. Such benefits have never been realized. In light of the just-released PHMSA Class Location Report,²⁵ those benefits are unlikely to ever be realized.

- Method 5 (“Pressure reduction for segments with small potential impact radius and diameter”) requirements for odorization and very frequent instrumented leak surveys make it impracticable. Those extremes far surpass the operations and maintenance requirements for pipelines even in Class 4 locations.
- Method 6 (“Alternative technology”) opens the door to technologies that probably do not currently, and may never, exist.

As noted, many of these methods will require extensive excavation and testing under Part §192.607 and the analysis of §192.624(d). While some of these more complex options may have to be used by an operator if a hydrostatic test cannot be performed, the more direct, thorough and technically well-founded approach recommended above should also be allowed, if not preferred. It has the advantages of analyzing the entire pipeline, establishing a lower bound yield strength for the entire pipeline, and providing the same margins of safety, based upon either the minimum yield strength or the prescribed Subpart J pressure test, as a new pipeline and provides a direct parallel to the requirements of §192.619(a) and §192.619(b).

In sum, only Method 1, the hydrostatic testing option proposed by PHMSA, with API’s proposed modifications, would be suitable to detect defects and potentially preventing an incident like the San Bruno pipeline rupture. See *NTSB Accident Report, Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, Sep. 9, 2010 (adopted Aug. 20, 2011) at p. 125* (stating as a finding of the report that if the ruptured line had not been grandfathered and had undergone a hydrostatic pressure test, this “would likely have exposed the defective pipe that led to this accident”). Review of existing records and excavating and testing approximately every mile might identify a short deficient pup or joint in the pipeline, but only by happenstance. Even an engineering critical assessment, unless accompanied by exhaustive ILI, might not identify a deficient pup and assign such properties that would warrant remedial action. ILI may be effective, where it can be performed, in allowing the operator to identify discrepancies between as-built drawings and records and actual pipeline configuration. Of all the methods suggested, short of wholesale pipe replacement, the API recommendation presented above (Section III.A.2), based upon hydrotesting and confirmatory ILI geometry tool runs, provides the highest probability of success in both preventing such incidents in the future and accomplishing the goals set by Congress and the NTSB on behalf of the public. Lastly, as outlined in Section II.C., API recommends that PHMSA include express exceptions for relevant gathering pipelines under §192.9(b).

b. Fracture Mechanics Modeling Requirement is Misplaced and Impractical

²⁵ See PHMSA-2010-0023 Rulemaking Docket, Report to Congress, *Evaluation of Expanding Pipeline Integrity Management Beyond HCAs*, listing a posting date of Jun. 9, 2016 (Class Location Report) available at <https://www.regulations.gov/#!documentDetail;D=PHMSA-2011-0023-0153>.

Proposed §192.624(d) would require fracture mechanics modeling for failure stress pressure and crack growth analysis where the operator has reason to believe that any pipeline segment contains or may be susceptible to cracks or crack-like defects. *NPRM at 20837*. The proposal for such analysis is elaborate, requiring operators to determine the remaining life of the pipeline at the MAOP based on applicable test pressures in accordance with proposed §192.506 (requiring spike hydrostatic pressure testing for existing steel pipe with integrity threats). *Id.* A fatigue analysis would be required to give conservative predictions of flaw growth and remaining life and, if the predicted remaining life of the pipeline calculated by the analysis is five years or less, then the operator must perform a pressure test or reduce MAOP. *Id. at 20838*. Remaining life of the pipeline would have to be re-evaluated before 50% of the remaining life calculated by the analysis has expired, within 15 years. *Id.*

It is unclear why fracture mechanics analysis, remaining life calculations, and retest or re-inspection interval determinations are included in the proposal for MAOP verification. These proposals are unnecessary, impracticable, and go far beyond the intent of the congressional mandates and the relevant NTSB recommendations. As an initial matter, API's proposed modifications (detailed in Sections III.A and III.D.5) to proposed §192.713 and §192.933 adequately address segments that contain or may be susceptible to cracks or crack-like defects.

Further, PHMSA's proposal specifies the material properties to be used in the analysis without consideration of the practical consequences of implementation. The proposal would require, for example, that operators use lower-bound toughness and strength properties for some calculations and upper-bound values for others. In the case of hydrotesting, an operator could end up with a "starting" flaw (based upon use of upper-bound properties) that is larger than the flaw size at failure (based upon use of lower-bound properties), potentially generating a negative fatigue life. *NPRM at 20837*. The stacking of multiple "conservative" values and methodologies is likely to produce results that are not useful, with many calculated retest intervals being negligibly short to even negative. The upshot would be an analysis showing that only the largest flaws could survive a hydrotest and those flaws will have a short life. The conservative principles in the proposal, when combined with ILI interaction rules for cracks or crack fields, will ensure that virtually any flaw has a short life to failure. Alternatively, the conservative estimates result in flaws being assigned failure pressures lower than known previous operating pressures. In short, the answers wrought by this analysis will be conservative, but unrealistic.

It is also not necessary to perform such an analysis along the entire length of the pipe. To begin with, the conversions between Charpy and toughness already carry an inherent amount of scatter. Enough data can be compiled to have a statistically confident answer by performing a limited number of tests. If results are pooled among operators of similar vintage and/or manufacturer, the results could be improved even more. Further, other studies have pointed to reasonable estimates to use for toughness that are not as onerous as the values listed in this NPRM.

In the case of ILI assessments, where actual values of material strength and toughness are not known, the proposal would require an operator to use conservative Charpy energy values of lower than or equal to 5.0 ft-lb for body cracks and 1.0 ft-lb for weld cracks. *Id.* While these values may be appropriate in some situations, they are overly conservative in most situations. Similarly, use of the Raju/Newman fracture mechanics model, as proposed under

§192.624(d)(3), is extremely conservative and therefore inappropriate in nearly all cases. Finally, for the reasons discussed above, API requests that PHMSA delete the reference in §192.624(c) for Methods 3 and 6 to obtaining a “no objection letter” from the PHMSA Associate Administrator.

B. Assessments and Repair Criteria Outside HCAs Should Focus on Risk

The NPRM proposes to apply aspects of integrity management (IM) requirements (*i.e.*, periodic integrity assessments and repair criteria) to onshore transmission pipelines outside of HCAs. *NPRM at 20838-20840*. These newly defined “moderate consequence areas” (MCAs) are intended to cover areas where people live and work and could reasonably be located within a pipeline “potential impact radius.” *NPRM at 20743, 20814-20815*. This proposed rule would add detailed periodic assessment and repair criteria requirements for all onshore transmission pipelines located in Class 3 and 4 locations and MCAs where the pipeline can accommodate an inline inspection tool. Further, detailed repair criteria would apply to any transmission pipeline not located in an HCA.

API and its members support improving pipeline safety through inspection of certain pipelines that are not currently covered by the IM rules and favor of a new category of pipelines based on similar concepts rather than expanding HCAs. API is concerned, however, that as drafted the Agency’s proposal is premature and would limit an operator’s ability to prioritize resources for pipelines that pose the highest risk to the public and the environment. In addition, the proposal is not based on risk but is instead based on the misguided principle that more is better—more pipeline assessments and more repair criteria—without grounding that determination in potential pipeline safety improvements and benefits to the public and the environment. Further, while API strongly supports limiting periodic assessment and repair criteria requirements to MCA segments that are capable of accommodating ILI tools, any expansion of these requirements to pipe in Class 1 and 2 locations that does not accommodate ILI would not be justified based on an analysis of the cost and benefits. API estimates that it would impose a significant cost on industry with very little benefit.

Section 5 of the 2011 amendments to the PSA required PHMSA to evaluate whether IM requirements should be expanded beyond HCAs and whether that would mitigate Class location requirements and provide a report to Congress by January 3, 2014. Various references in the NPRM indicated that some version of the report was already in the rulemaking docket, but that a more fulsome evaluation was not yet complete. *NPRM at 20733; 20737; 20743; 20754*. Without explanation or justification by the Agency, the report was not made available or posted to the docket in any form until 2 months after publication of the proposed rule, over 2.5 years after the statutory deadline, on June 9, 2016. *See Class Location Report, PHMSA-2010-0023 Rulemaking Docket, listing a posting date of Jun. 9, 2016*.

It is premature for PHMSA to propose application of IM assessment and repair criteria to such a large portion of gas transmission pipelines when it has not allowed Congress, industry and the public sufficient time to review and assess the report’s findings as they relate to this rulemaking. Further, the report itself is void of explanation and justification behind PHMSA’s proposed expansion of certain integrity management requirements.

In addition, any new category of non-HCA pipelines subject to assessment and repair requirements should be guided by an accurate and complete cost-benefit analysis. As noted above in Section I.A., PHMSA's cost benefit analysis for these provisions is neither accurate nor complete. These broad assessment requirements and detailed repair criteria as applied to possibly tens of thousands of miles of pipelines within 15 years would be an unprecedented undertaking for the Agency and the industry. PHMSA readily admits this in the NPRM, noting that the rules would require "full utilization or expansion of industry resources devoted to assessments." *NPRM at 20733*.

Existing Part 192 regulations already require operators to perform certain testing and assessments outside of HCAs (*e.g.*, operation and maintenance measures such as leak surveys, patrols, corrosion control monitoring and repairs, preventive and mitigative measures outside HCAs, and requirements to assess the entire segment when corrosive conditions are found). Further, many operators have voluntarily assessed pipelines outside of HCAs in conjunction with their integrity management assessments. For those reasons, a majority of industry commenters on PHMSA's ANPRM did not support expansion of integrity requirements outside of HCAs. *NPRM at 20749*.

Taken together, the rules as drafted would create unnecessary safety costs without a demonstrated commensurate safety benefit. For that reason, and as explained below, API requests that PHMSA provide additional clarifications regarding the scope of the rule, assessment methods, and repair criteria to allow operators to focus resources on the highest risks presented maintain the flexibility to apply these requirements to operating pipeline systems.

1. Assessments Outside of HCAs

As set forth under proposed rule, 49 C.F.R. §192.710, transmission pipelines located in Class 3 and 4 locations and pipelines located in MCAs that can accommodate an inline inspection tool (that are not located in HCAs) must be assessed within 15 years of the effective date of the rule and again at least once every 20 years "or a shorter interval" based upon several characteristics. API recommends various aspects of this proposal warrant further clarification and additional consideration, including the definition of MCA, exceptions for low risk pipelines, acceptable assessment methods, and reassessment intervals.

a. Applicability and Scope of MCAs Requiring Assessment

Under PHMSA's proposed rule, MCAs would include onshore areas:

within a potential impact circle[...] containing five (5) or more buildings intended for human occupancy, an occupied site [see below], or a right-of-way for a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway [...], and does not meet the definition of high consequence area[...].

NPRM at 20826. An occupied site would include the following areas: (1) an outside area or open structure occupied by 5 or more persons on at least 50 days in any 12-month period (*e.g.*, 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 occupied by 5 or more persons on at least 5 days a week for 10 weeks in any 12-month period (e.g. religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks). *Id.*

API understands the need for a new category of MCA pipelines and agrees with PHMSA's proposal to include all Class 3 and Class 4 locations, occupied sites and major highways. Without support or justification in the NPRM, the Preliminary RIA or the Agency's late-breaking Class Location Report, however, PHMSA posits that the MCA threshold number of buildings intended for human occupancy within the potential impact radius should be 5. *NPRM at 20746; Preliminary RIA; Class Location Report.* This number is completely arbitrary and has no basis in the regulations or calculation of risk. API, in agreement with AGA, recommends that the appropriate threshold is more than 10 buildings intended for human occupancy as that number is consistent with longstanding Part 192 Class location designations and would include all Class 2 locations (defined to include 11-46 buildings intended for human occupancy) and the most populated Class 1 locations (defined to include 10 or fewer buildings intended for human occupancy). In addition, API recommends that PHMSA clarify that "other principal 4-lane arterial roadways" include those with 4 or more lanes.

Further, API echoes AGA and INGAA's comments on the modification to PHMSA's proposed MCA definition and suggests removing the reference to "a right-of-way" for the designated roadways. Roadway rights-of-way are variable, cannot be seen with the naked eye, and are often not included in publicly available data sources. In addition, rights-of-way can vary significantly from near the edge of pavement to several hundred feet away and for that reason they may not adequately represent the consequence area that PHMSA intends to capture under this definition. Instead API suggests that the right-of-way reference be removed and replaced with "edge of paved surface." In order to properly capture movement along one of these major roadways, API supports the inclusion of a predefined buffer for all pipelines from both edges of paved surfaces. This approach captures PHMSA's intent, but does so in a manner which will prevent operators from having to determine each individual roadway's specific right-of-way width. API proposes a 50 foot buffer, which represents the average right-of-way width for the roadways that PHMSA has included in this definition.

For those reasons, the proposed definition of MCA under §192.3 should be revised as follows:

§ 192.3 Definitions.

Moderate consequence area means an onshore area that is within a potential impact circle, as defined in § 192.903, containing ~~five (5)~~ **more than ten (10)** or more buildings intended for human occupancy, an occupied site, **or within 50 feet of the outermost edge of paved surface, including the mainlanes, frontage lanes, ramps, and other facilities designed to be regularly used by traffic, a right-of-way** for a designated interstate, freeway, expressway and other principal ~~4-lane~~ **of four or more lanes**, 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)~~ **more than ten (10)** or more buildings intended for human occupancy, ~~or a right-of-way or within 50 feet of the outermost edge of paved surface, including the mainlanes, frontage lanes, ramps, and other facilities designed to be regularly used by traffic, for of~~ **of a designated interstate, freeway, expressway, or other principal 4-lane-arterial roadway of four or more lanes**, to the outermost edge of the last contiguous potential impact circle that contains either an

occupied site, ~~five (5)~~ **more than ten (10)** or more buildings intended for human occupancy, ~~or a right-of-way or within 50 fifty feet of the outermost edge of paved surface, including mainlanes, frontage lanes, ramps and other facilities designed to be regularly used by traffic.~~

With respect to the definition of “occupied site” under §192.3, PHMSA should clarify that, consistent with established Class location and HCA definitions, buildings do not include residential dwellings as follows:

§ 192.3 Definitions.

- (1) [...]; or
- (2) A **non-residential** 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.) [...].

PHMSA’s proposed regulation at §192.710 regarding MCA applicability would benefit from additional revision and clarification. First, while the proposed rule applies to transmission pipelines, as outlined in Section II.C., API recommends that PHMSA include an express exception under existing §192.9(b) so that relevant exceptions for gathering pipelines are included.

Along those same lines, low stress pipelines operate below 30% SMYS and are generally smaller in diameter than typical transmission pipelines. As such, they present a much lower risk to the public and the environment as compared to higher stress pipelines. API requests that PHMSA exclude these pipelines entirely from assessment requirements as existing external and internal corrosion control monitoring under Part 192, Subpart I provide sufficient protections (and would be supplemented further by proposed additional corrosion control requirements). In addition, API recommends that the circumstances under which an operator may demonstrate that a pipeline is not capable of accommodating an inline inspection tool be defined, including but not limited to product flow rate, physical configuration, potential service interruptions, and line diameter, among others and be determined on a case by case basis.

For those reasons, §192.710 should be revised as follows:

§ 192.710 Pipeline assessments.

- (a) Applicability. (1) This section applies to onshore transmission pipeline segments that are located in:
 - (i) A Class 3 or Class 4 location; or
 - (ii) A moderate consequence area as defined in § 192.3 if the pipe segment can accommodate inspection by means of instrumented inline inspection tools (i.e., “smart pigs”). **Whether a pipeline segment can accommodate inspection by instrumented inline inspection is determined by the pipeline segment characteristics including but not limited to product flow rate, physical configuration, potential service impacts, and line diameter.**
- (2) This section does not apply to a pipeline segment located in a high consequence area as defined in § 192.903.
- (3) **This section does not apply to a pipeline transmission pipeline segment that operates below 30% SMYS.**

b. Initial Assessment Period and Reassessment Interval

Generally speaking, API agrees with PHMSA's proposed timeframe for compliance with initial MCA assessment periods (15 years) and reassessment intervals (every 20 years thereafter). With regard to the reassessment interval, the proposal requires a shorter reassessment interval than 20 years "based upon the type [of] anomaly, operational, material and environmental conditions [...], or as otherwise necessary." Because this language is vague and subject to varying interpretations, API respectfully requests that PHMSA revise §192.710(b)(1) as follows:

§ 192.710(b)(1) Pipeline assessment, General.

An operator must perform initial assessments in accordance with this section no later than [date 15 years after effective date of the final rule] and periodic reassessments every 20 years thereafter, or a shorter reassessment interval ~~internal~~-based upon the judgment of the operator and the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, ~~or as otherwise necessary to ensure public safety.~~

c. Maintain Operator Flexibility in Assessment Methods

Many operators have already performed inspections on pipelines outside of HCAs in conjunction with Part 192 Subpart O IMP requirements. Under the Agency's proposal, PHMSA allows operators to rely on prior assessments conducted under IMP, but this allowance is limited to inline inspection. API requests that PHMSA allow operators to rely on any prior assessments performed under Subpart O requirements in effect at the time of the assessment as follows under §192.710(b)(2):

§ 192.710(b)(2) Pipeline assessment, Prior assessment.

An operator may use a prior assessment conducted before [effective date of the final rule] as an initial assessment for the segment, if the assessment meets the subpart O of this part requirements for assessments performed under §192.921, in effect on the date the inspection was performed in-line inspection. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(1) of this section.

Further, §192.710(b)(3), which allows operators to use assessments performed in conjunction with MAOP verification, requires clarification. It is unclear whether all of the six "methods" under §192.624(c) are available to satisfy the §192.710 assessment requirement, since three of those methods may not be "integrity assessments" because they include pressure reduction and pipe replacement. PHMSA should also clarify that this option applies regardless of fracture mechanics modeling under §192.624(d).

§ 192.710(b)(3), Pipeline assessment, MAOP Verification

(3) MAOP verification. An operator may use an ~~integrity~~-assessment to meet the requirements of this section for a segment if the ~~pipeline segment~~ assessment is conducted in accordance with ~~the integrity assessment requirements of~~ § 192.624(c)(1), (3) or (6) for establishing MAOP.

In addition, PHMSA does not clarify how newly installed pipe will be treated in the NPRM. Similar to the regulation regarding newly identified HCAs at §192.905(c), API proposes the following language to §192.710(b)(4) to address newly installed pipe.

§ 192.710(b)(4) Pipeline assessment, Newly Installed Pipe and Identified Areas.

- (4) Newly installed pipe and identified areas. An operator must perform an initial assessment in accordance with this section within 15 years of installing a new segment of pipe covered under subsection (a) or identifying an existing segment of pipe covered under subsection (a) in a newly identified moderate consequence area as defined in §192.3. Periodic reassessments of these segments must be conducted in accordance with the requirements in paragraph (1) of this subsection.**

PHMSA would require assessments by methods that are capable of identifying anomalies and defects “associated with each of the threats to which the pipeline is susceptible and must be performed using one or more of [8] methods.” *NPRM at 20838 (proposed 192.710(c))(emphasis added)*. Further, the rule later clarifies that in complying with the rule, an operator must consider “all available information about a pipeline.” *NPRM at 20838 (proposed 192.710(g))*. PHMSA has not adequately accounted for the time, effort, resources, and costs to compiling this amount of data and perform threat assessments on these pipelines. Any final rule must acknowledge those costs and provide operators with flexibility in performing pipeline assessments.

With respect to the assessment methods, they must “be capable of identifying anomalies and defects associated with each of the threats to which the pipeline is susceptible and must be performed using one or more” of 6 methods. *NPRM at 20838*. As proposed, however, the inline inspection tool method (Method 1) states that a crack tool is required for every assessment, regardless of whether there is a threat of cracking on a particular segment. *Id.* PHMSA indicated in a recent webinar on the NPRM that Method 1 should only require operators to use tools address the threat(s) to the pipeline (as opposed to all tools). For that reason, API recommends making the following revision to §192.710(c)(1) to eliminate redundant text that is subject to varying interpretations:

§ 192.710(c)(1) Assessment Method, Method 1.

(1) Internal inspection tool or tools ~~capable of detecting corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots, and any other threats to which the segment is susceptible~~. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493.

Even though API recommends that low stress pipelines should be expressly excepted from this rule, if PHMSA elects to apply the rule to these pipelines, the Agency should at a minimum revise proposed §192.710(c)(8) to make clear that low stress segments assessed by the other methods listed in §192.710(c)(1 - 7) do not need to also comply with (c)(8). This would require a simple revision to §192.710(c)(8): “For segments with MAOP less than 30% of the SMYS, an operator ~~must~~ may assess for the threats of external and internal corruptions as follows [...]”

d. Duplicative Requirements Should be Avoided

PHMSA is proposing ILI requirements that are misplaced, duplicative, and unnecessary. The language proposed in §192.493 references consensus standards for inline inspection, incorporating API 1163 ILI Systems Qualification Standard, ANSI/ASNT ILI-PQ-2005, ILI Personnel Qualification and Certification and NACE SP0102-2010, ILI of Pipelines. API believes this is misplaced in the corrosion control section, as the requirements have broader implications than corrosion control. The language in §192.493 is stronger than that proposed in

§192.710 (d), §192.921 (a)(1), and §192.937 (c)(4). Therefore, API proposes that the language in the aforementioned sections be replaced with the language in §192.493 and §192.493 be deleted. This is consistent with the NTTA (explained in Section II.A.).

Further, §192.710(f) regarding remediation should be revised to eliminate the vague reference to “conditions that could adversely affect safe operations” as follows:

§ 192.710(f) Pipeline assessment, Remediation.

~~“An operator must comply with the requirements in § 192.713 if a condition that could adversely affect the safe operation of a pipeline is discovered. In determining whether a condition discovered by an assessment requires remediation, an operator must comply with §§ 192.711 and 192.713”~~

In addition, API requests under §192.710(g) that PHMSA clarify that an operator must only consider all available “relevant” information about a pipeline.

§ 192.710(g) Pipeline assessment, Consideration of information.

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

2. Repair Criteria Outside of HCAs

PHMSA’s proposal establishes criteria for immediate repair, two year and monitored conditions for all non-HCA transmission pipelines. *NPRM at 20815*. API appreciates PHMSA efforts to provide guidance regarding repair and repair timing in non-HCA areas. These proposed changes, however, signal a move to more prescriptive requirements in certain areas, which can be inefficient, are contrary to a risk-based or risk-informed decision process and may discourage technological advancements. If implemented, this proposal will significantly increase the number of required (and costly) digs for non-HCA areas, often times regardless of risk and where they are unnecessary.

Further, neither the background materials nor the preamble to this rulemaking attempt to quantify the actual safety benefit that may be reasonably expected from these repair criteria. For example, there is no analysis of incidents that have occurred during the past 10-15 years since the advent of the integrity management rules to determine which of those incidents would likely be prevented if the proposed requirements are implemented. Without such analysis to demonstrate the need for the requirements and determine the specific criteria, it appears that they are based on a “more is better” approach. Excavating a pipeline to address a low risk feature is counter to a risk-based approach.

a. Lack of Definitions for Repair, Response, Remediation, and Mitigation

Throughout the NPRM and in particular the repair criteria proposals, PHMSA uses the terms “repair,” “response,” “remediation,” and “mitigation” interchangeably. The only term defined in Part 192 is “remediation” and it is defined under the integrity management rules at Subpart O. *49 C.F.R. §192.903* (to mean a “repair or mitigation activity an operator takes on a covered

segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event”). Actual remediation and repair decisions are made based on the observed feature, not just the ILI indication, once the operator gains additional information on the correlation between ILI indications and actual features. With this in mind and for purposes of consistency in application of these terms, API recommends that PHMSA move the definition of remediation to §192.3 and add definitions for “repair,” “response,” and “mitigation” as follows:

§ 192.3 Definitions.

- a. **Repair means the action taken by an operator to restore the pipeline or associated facilities to an acceptable condition. The acceptable condition is defined by this part, standards incorporated by reference in this part, or engineering judgment.**
- b. **Response means an operator’s action(s) to determine whether an indication of a potentially anomalous condition is, in fact, a condition requiring remediation.**
- c. **Mitigation means the act of making a condition or consequence less severe through pipeline repair, replacement, selected preventive and mitigation activities, consequence reduction, or a combination of these activities.**

b. General Repair Requirements

API supports the intent of the general requirements for repair procedures. The phrases “impairs its serviceability” and “could adversely affect,” however, are imprecise and could be subject to a wide range of interpretation or application on a case-by-case or location-by-location basis. For that reason, API requests that PHMSA revise the rule so that these phrases will not be construed too broadly such that any deviation from pristine pipe and components “impairing serviceability” or that “could adversely affect” conditions are included.

API suggests that such conditions be revised under §192.711 in order to include specific defined criteria. In addition, API proposes to revise the section to “temporary measures” (as opposed to “temporary repairs”) to be consistent with the text of the rule (to take “immediate temporary measures”) and API’s proposed definitions listed above. In sum, API requests that PHMSA revise §192.711 in relevant as follows:

§ 192.711 Transmission lines: General requirements for repair procedures.

- (a) **Temporary repairs measures.** Each operator must take immediate temporary measures to protect the public whenever:
 - (1) A leak, imperfection, or damage that **requires an immediate response under §192.713(d)(1)** impairs its **serviceability** is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and
 - (2) It is not feasible to make a permanent repair at the time of discovery.
- (b) **Permanent repairs.** An operator must make permanent repairs on its pipeline system according to the following:
 - (1) Non integrity management repairs: Whenever an operator discovers any condition ~~that could adversely affect the safe operation of a pipeline segment~~ that requires **remediation under §192.713(d)(1), (d)(3) or (e), not covered under Subpart O of this part, Gas Transmission Pipeline Integrity Management**, it must correct the condition as prescribed in 192.713. ~~However, If the condition~~ **requires remediation under §192.713 (d) (1) is of such a nature that it presents an immediate hazard to persons or property**, the operator must reduce the operating pressure to a level not exceeding 80% of the operating pressure at the time

the condition was discovered and take additional immediate temporary measures in accordance with paragraph (a) of this section to protect persons or property. ~~The operator must make and make~~ permanent repairs as soon as feasible.

c. Repair Criteria Outside of HCAs Should Include Engineering Analysis

Advances in inspection detection technology have greatly improved the industry's ability to detect and evaluate threats to pipeline integrity. Similarly, research on pipe strength and failure mechanics has improved the industry's ability to more accurately predict the safety of pipeline operations. As such, API recommends that repair conditions reflect advances in metallurgy and fracture mechanics. In addition, repair criteria should allow operators to use engineering analyses to demonstrate that an anomaly does not pose a risk to pipeline integrity. This becomes particularly evident when comparing the requirements in §192.710 with those in §192.713. If, for example, an operator performs a pressure test in accordance with §192.710 on crack-like features or deformations and the results are determined to be acceptable and regarded not a threat to pipeline integrity, there is no need for an operator to take further action under §192.713.

In order to avoid duplicative requirements, PHMSA should allow the operator to rely upon an engineering analysis under §192.713. Further, API proposes to define an engineering analysis to include: **“a publicly available and commonly used study, approved standard, or practice available (e.g., PRCI, ASME) for guidance in addressing pipeline integrity.”**

d. General Requirements & Repair Criteria Require Clarifications

The NPRM proposes extensive field repair criteria for all transmission pipelines under revised §192.713. These requirements would apply pipelines in HCAs and states that those pipelines must also comply with integrity management repair requirements under Subpart O. Imposing two different sets of repair criteria on pipelines located in HCAs is duplicative and could create conflicting requirements. In addition, the specific repair criteria would benefit from additional clarifications to be consistent with §192.711(b) and to include allowances for an operator to use established repair techniques.

For those reasons, API proposes the following changes to §192.713:

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

- (a) This section applies to transmission lines **not covered under Subpart O Gas Transmission Pipeline Integrity Management.** Line segments that are located in high consequence areas, as defined in §192.903, must ~~also~~ comply with applicable actions specified by the integrity management requirements in subpart O of this part.
- (b) *General.* Each operator must, in repairing its pipeline systems, ~~ensure that make~~ the repairs ~~are made~~ in a safe manner and ~~are made~~ so as to prevent damage to persons, property, or the environment. Operating pressure must be at a safe level during repair operations.
- (c) *Repair.* Each imperfection or damage that impairs the serviceability, **i.e. affects the continued safe operation,** 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;.
 - (3) **Remediated such that safe operation is reestablished; or**

- (4) Repaired using an acceptable method identified in ASME/ANSI B31.8 (incorporated by reference at §192.7).

Similar to the existing integrity management rules, PHMSA's repair criteria should incorporate established industry standards regarding calculating a predicted burst pressure. In addition, the regulation should incorporate concepts in forthcoming API Recommended Practice 1176, Assessment and Management of Cracking in Pipelines, to provide additional clarity regarding likely cracks and possible cracks. Further, PHMSA should provide for and clarify what an acceptable engineering analysis includes. As such, API proposes that PHMSA consider adding *new* section under §192.713(d), before immediate repair conditions, as follows:

§ 192.713(d) Transmission lines: Permanent field repair of imperfections and damages, Remediation schedule.

- (1) In calculating a predicted burst pressure for the purposes of determining remaining strength, selection of a suitable calculation method depends on several factors, including the failure mode of the anomaly. Appropriate calculation methods include, but are not limited to:**
 - (i) For metal loss anomalies susceptible to failure in plastic collapse: ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (2012) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989));**
 - (ii) For crack anomalies or selective seam weld corrosion (SSWC) associated with EFW and vintage ERW seams susceptible to failure through fracture: the Battelle Model (Modified Log-Secant), CorLAST™ or API 579 Part 9;**
 - (iii) For dent anomalies: the safe working pressure can be determined using PRCI PR-218-063505 "Safe Inspection Procedures for Dent and Gouge Damage" (2010).**
- (2) For purposes of this section, a likely crack is defined as having a reasonable degree of confidence that the anomaly called by the ILI vendor correlates to a crack defect. This can be the case where the operator's previous experience on the present pipeline segment or other similar pipeline segment has found cracks or the case where the data integration indicates a strong likelihood that cracks could exist even though no historical data suggests so. A possible crack is defined as having a reduced certainty of being an actual crack and, when it is a crack, it occurs under different circumstances or the operator cannot determine with a high degree of confidence that the indication is not a crack defect.**
- (3) For purposes of this regulation, an engineering analysis must include operator documentation and provide adequate technical justification for not completing repair or remediation of identified conditions within the specified timeframe. All evaluations must be performed by qualified persons, be based on sound engineering principles, and must account for the following factors at a minimum:**
 - i. Metal loss: predicted flaw dimensions, material properties, tool tolerance, failure mode, and predicted growth rate**
 - ii. Crack indications: predicted flaw dimensions, material properties, tool tolerance, failure mode, operational pressure cycles, and predicted growth rate**
 - iii. Dents: predicted flaw dimensions, material properties, tool tolerance, failure mode, operational pressure cycles, and predicted growth rate of corrosion and/or cracks.**

e. Immediate Conditions

The Agency's proposal to update regulations for repair of gas transmission pipelines provides PHMSA with the opportunity to reflect advances in inspection detection technology and our improved ability to detect and understand threats to pipeline integrity. Yet as proposed in the NPRM, operators will be required to automatically treat certain indications as immediate repair

conditions without the ability to perform additional engineering analysis to confirm whether there is an actual threat to pipeline integrity. *NPRM at 20839-20840.*

Therefore, API suggests that PHMSA strengthen the immediate repair criteria by adding a repair condition for likely crack anomalies greater than 70% of nominal wall thickness. This change would reflect the latest industry recommendations for repairing crack anomalies. API also recommends PHMSA include criteria to provide for consideration of both metal loss features associated with plastic collapse and cracking that is considered a fracture mechanics feature. Further, API proposes revisions to §192.713 on dent-related conditions to eliminate immediate criteria for anomalies that historically do not pose a near term risk of release. This is consistent with established industry guidelines. *See Kiefner & Associates, Guidelines for the Assessment of Dents on Welds, # PR-218-9822 (Dec. 21, 1991).*

The NPRM would require immediate repair of “any indication” of “significant” stress corrosion cracking (SCC) or selective seam weld corrosion (SSWC). *NPRM at 20839 (proposed §192.713(d)(1)(v - vi)).* API agrees with PHMSA’s desire for operators to appropriately mitigate the threat of SCC, however, a requirement to immediately repair *any* indication of this type of threat is overly broad and wasteful. ILI technology is such that it can detect even the smallest of pipe features, yet industry’s ability to assess remaining strength characteristics and fracture mechanics is such that not all indications require immediate repair.

API strongly opposes a rule that requires immediate repair for any indication of SCC and SSWC and recommends that the terms “any indication” and “significant” be removed from the rule and be tied to established industry guidance.²⁶ The “significant” designation is also not representative of the severity of the anomaly, which is described by maximum depth or failure-pressure ratio, FPR. Instead, API proposes that SCC and SSWC concerns would be sufficiently addressed through (1) adoption of a new criterion for likely crack anomalies greater than 70% of nominal wall thickness and (2) expanding the potential approaches for calculating remaining strength of pipe.

API also proposes that PHMSA delete the requirement for immediate repair to pipelines with metal loss greater than 80% of nominal wall regardless of dimensions. PHMSA bases integrity criteria on established industry standard ASME B31.8S, which is a (predicted burst) pressure-based assessment criteria. The proposed rule would then override ASME, however, by including depth based criteria (% of nominal wall) into the rule. The inclusion of both criteria is confusing and contradictory. API believes that establishing one recognized standard will promote pipeline safety and compliance and support remediation decisions based on burst pressure assessment criteria in ASME B31.8S.

²⁶ If PHMSA’s addition of “significant” criteria is intended to add language similar to the Canadian Energy Pipeline Association’s (CEPA) “significant” criteria, it is important to recognize that this CEPA measure had no basis for assessing an individual feature’s level of severity. Instead, it was designed to be applied to field-identified and confirmed SCC and to provide a reporting threshold to support an information gathering exercise. It was not meant to correlate to fitness for purpose (FFP) assessments, which appears to be PHMSA’s aim. Additionally, the CEPA definition does not provide clarity on the particular operator actions to ensure safety relating to SCC, as ILI data does not identify or delineate this anomaly directly.

Further, PHMSA's proposal for pressure reductions pending remediation is overly conservative. Proposed §192.713(d)(2)(i) would require that operators reduce pressure to the lowest of "a level that restores the safety margin commensurate with the design factor for the Class location in which the affected pipeline is located" (using ASME/ANSI B31G for corrosion defects) or 80% of pressure at the time of discovery. If the first method is chosen, and SMYS or actual material yield and ultimate tensile strength is not known or not adequately documented by the undefined "reliable, traceable, verifiable, and complete" records standard, then the operator must assume grade A pipe or determine the material properties based upon the specifications of proposed §192.607. API submits that, similar to its comments on proposed §192.607, this methodology would be overly conservative (if grade A pipe is assumed) or burdensome (if proposed §192.607 requirements are followed) relative to the safety benefits conferred. API therefore proposes several changes to §192.713(d)(2)(i), that would allow operators to choose the higher of the two options for calculating reduced pressure and that would eliminate the proposed reference to the undefined "reliable, traceable, verifiable, and complete" standard for material documentation and the verification process set forth in proposed §192.607.

Specifically, API requests the following modifications to the immediate repair conditions in §192.713(d):

§ 192.713(d) Transmission lines: Permanent field repair of imperfections and damages, Immediate repair conditions.

- (1) *Immediate repair conditions.* An operator must repair, per the requirements of §192.713(c), the following conditions immediately upon discovery:
 - (i) A calculation of the remaining strength of the pipe shows a predicted ~~failure-burst~~ pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. ~~Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in § 192.7(c). Pipe and material properties used in remaining strength calculations must be documented in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607. The operator must document the basis for pipe and material properties used in remaining strength calculations.~~
 - (i) A dent that has any indication of metal loss, a gouge, cracking or a stress riser unless an engineering analysis shows that it poses minimal risk to pipeline integrity.
 - ~~(ii) Metal loss greater than 80% of nominal wall regardless of dimensions.~~
 - (iii) Likely crack anomalies greater than 70% of nominal wall or of an indeterminate depth regardless of dimensions or the maximum depth sizing capabilities of the tool, as set forth in the vendor's performance specification, where the depth cannot otherwise be established through correlation with prior ILI runs.
 - (iv) An indication of metal-loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high frequency electric resistance welding or by electric flash welding.
 - ~~(v) Any indication of significant stress corrosion cracking (SCC)~~
 - ~~(vi) Any indication of significant selective seam weld corrosion (SSWC).~~
 - (vii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

- (2) Until the remediation of a condition specified in paragraph (d)(1) is complete, an operator must reduce the operating pressure of the affected pipeline ~~to the lower of~~ to the no more than the higher of:
 - (i) A level that restores the safety margin commensurate with the design factor for the Class Location in which the affected pipeline is located, determined using ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1994) (2012) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)) ("RSTRENG," incorporated by reference, see § 192.7) for corrosion defects. ~~Both procedures apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations procedures.~~ When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, crack-related defects, appropriate failure criteria and justification of the criteria must be used. If SMYS or actual material yield and ultimate tensile strength is not known ~~or not adequately documented by reliable, traceable, verifiable, and complete records,~~ then the operator must assume grade A pipe ~~or determine the material properties based upon the material documentation program specified in § 192.607,~~ or
 - (ii) 80% of pressure at the time of discovery, ~~whichever is lower.~~

f. Two -Year Conditions Require Clear and Practical Criteria

PHMSA proposes that a number of conditions on non-HCA pipelines require repair within two years of discovery. *NPRM at 20840*. While API agrees with the intent of imposing two-year repair criteria, the proposed rule needs more transparent, objective and practicable criteria. Specifically, modifications should be made to associate predicted failure pressure ratio to both metal loss and cracking. In order to further address PHMSA's SSWC concerns, API suggests the revisions below to paragraph (iv) account for intermediate depth anomalies in locations where there is more likely to be an accelerated corrosion rate or is more difficult to quantify because of widespread corrosions. Given that SSWC is otherwise addressed within the proposed criteria, API believes that there is no basis for a criterion regarding corrosion that is coincidentally of or along a seam weld.

Therefore, API offers the following changes to the two year and monitored conditions proposed in §192.713(d)(3):

§ 192.713(d)(3)-(4) Transmission lines: Permanent field repair of imperfections and damages, Two-year condition.

- (3) *Two-year conditions.* An operator must repair the following conditions within two years of discovery:
 - (i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) for which engineering analyses of the dent demonstrate critical strain levels have been exceeded or, if such a strain determination is not made, 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) unless an engineering analysis shows that it poses a minimal risk to pipeline integrity.
 - (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 **detected** longitudinal or helical (spiral) seam weld unless an engineering analysis shows that it poses a minimal risk to pipeline integrity.
 - (iii) A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio (FPR) at the location of the metal loss or likely or possible crack ~~of the anomaly~~ less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4

locations. This calculation must adequately account for the uncertainty associated with the accuracy of the tool used to perform the assessment.

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

~~(iv)~~ (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 or general corrosion, or is in an area that could preferentially affects a girth weld or a detected seam weld.

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

~~(vi)~~ A likely or possible crack with depth greater than 50% of nominal wall.

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

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

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located anywhere on the pipe for which engineering analyses of the dent demonstrate critical strain levels are not exceeded and there are no additional exacerbating factors, such as gouges or other stress risers 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.~~

C. Corrosion Control Requirements are Unnecessary

The NPRM proposes revisions to Subparts G, I, M and O of 49 C.F.R. Part 192, adding and revising existing requirements related to corrosion control in natural gas steel pipelines. *NPRM at 20829-20830, 20843-20844, 20846.* As noted by PHMSA in response to comments submitted on the ANPRM for this rulemaking, the overwhelming majority of comments stated that there is no need to revise the existing rules for corrosion control. *NPRM at 20782-20783.* The existing requirements for corrosion control under Part 192 are already extensive, incorporating the standards in ASME B31.8 that have been in place for many decades.

Moreover, pipeline operators follow dozens of other industry standards in addressing issues related to corrosion, including corrosion prevention, cathodic protection, coatings, field monitoring, and inspection and assessment techniques. *See Michael Baker Jr., Inc., Pipeline Corrosion, Final Report, prepared for the U.S. DOT, PHMSA (Nov. 2008), pp. 47-50.* There is nothing in the record to suggest that the corrosion control practices detailed in these industry standards are inadequate, or that pipeline corrosion would be more effectively managed if PHMSA implemented the proposals offered in the NPRM. Federal law requires PHMSA to adopt industry standards, rather than government-unique requirements, unless doing so would be inconsistent with the requirements in the PSA or otherwise impracticable. *15 U.S.C. § 272 note; Pub. L. 104-113, NTTA; Revised OMB Circular A-119, 63 Fed. Reg. 8546 (Feb. 19, 1998).* The record does not show that PHMSA even considered that obligation before proposing the corrosion control requirements in the NPRM.

Providing further evidence of the fact that the existing regulatory framework for corrosion control is effective, PHMSA's own database shows that the number of gas transmission pipeline incidents caused by corrosion and the percentage of incidents caused by corrosion as compared to other causes has significantly declined over the past 20 years. *PHMSA Incident Trends Statistics*, <http://www.phmsa.dot.gov/pipeline/library/data-stats/pipelineincidenttrends>. Since

2013, an average of just 16.46% of all gas transmission incidents has been caused by corrosion, down from a peak of 35% in the year 2000. *Id.* In addition, the overall safety of pipeline operations has improved dramatically in the last 20 years, with the number of serious gas transmission pipeline incidents down by more than 50%. *Id.*

The NPRM refers to a few isolated incidents, all of which occurred between five to ten years ago, as the underlying rationale for adding new requirements to existing corrosion control regulation, to be applied generically across the industry (despite the fact that the few incidents noted as support for the new rules had unique fact settings). The data cited by the NPRM, and the declining record of incidents caused by corrosion, show that establishing these proposals as new requirements is not supported by any associated need or improvement in public safety or pipeline integrity. Thus, there would simply be no economic benefit as a result of implementing these new proposed requirements.

Long term studies, which pre-date by many decades the establishment of the PSA, demonstrate that steel pipe that is adequately protected from corrosion has an indefinite life. *Kiefner & Trench, Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction, p. 11 (Dec. 2001)* (“Pipe that is adequately coated and cathodically protected, as well as properly inspected and maintained, will not be degraded by corrosion.”). Adequate protection is provided through coating, and through cathodic protection. Coating is inspected at the time of construction, during repair activities and during any other occasion that exposes pipe from soil cover. The sufficiency of cathodic protection is monitored through frequent inspections and testing (bi-monthly and annually, depending on the type of test). Current PHMSA regulations require all of these activities.

This proposed rule would add and/or revise a number of new and extensive requirements regarding corrosion control, including:

- (1) enhanced requirements for close interval surveys (CIS) (§192.319);
- (2) post construction coating surveys (§192.461; §192.465);
- (3) interference current surveys (§192.473);
- (4) new requirements for internal corrosion control (§192.478); and
- (5) corrosion control remedial measures (§192.485).

To PHMSA’s credit, comments submitted on the ANPRM on several additional topics persuaded the Agency to withdraw or suspend action on additional additions to the Part 192 proposed rules. The NPRM acknowledges that the majority of commenters on the ANPRM for the topics listed above believed that no new requirements were necessary and that the Agency was proposing generic changes to address case specific or isolated instances. API respectfully suggests that the remaining proposed additions to the existing corrosion control regulations are unnecessary, and that the projected cost is much greater than the projected benefit.

Comments on specific elements of the proposed new corrosion control regulations are noted below. In addition to the proposed comments and revisions below, API recommends that PHMSA include express exceptions for relevant gathering pipelines under §192.9(b) (as outlined in Section II.C).

1. Enhanced Requirements for Close Interval Surveys are Vague

The NPRM proposes to define the term “close interval survey” at §192.3, revise §192.465 for external corrosion monitoring to mandate the use of close interval surveys (CIS) any time an annual test station (pipe to soil) reading is below the cathodic protection (CP) levels required in Part 192, Appendix D. *NPRM at 20829*. The CIS must be conducted in both directions from the test station, at five foot intervals, until the extent of the CP deficiency is identified. An added clarification to §192.465(d) would require that any CP remediation associated with the CIS identified area of deficiency must be completed “promptly,” which would be defined to mean “no later than the next monitoring interval...or within one year, whichever is less.” *NPRM at 20829*. The CIS surveys would have to be conducted with the current interrupted. *Id.*

As a threshold comment, API believes that the definition of CIS is vague and subject to varying interpretations. For that reason, API recommends that PHMSA use the definition in established industry standard, NACE SP0207, *Performing Close Interval Potential Surveys & DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines* (2007). As such, §192.3 would be revised as follows:

§ 192.3 Definitions.

Close interval survey means ~~a series of closely spaced pipe to electrolyte potential measurements taken to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary.~~ potential survey performed on a buried or submerged metallic pipeline in order to obtain valid direct current (DC) structure-to-electrolyte potential measurements at a regular interval sufficiently small to permit a detailed assessment.

API agrees that discovery of a deficiency in the CP system must be promptly remediated. API believes these new CIS requirements are unnecessary, however, because operators already use the annual CP test methods and bi-monthly CP monitoring data to determine any deficiencies in CP applied to the pipe. Further, requiring that the CIS be conducted with the current interrupted is impractical, in particular for gathering lines. While CIS is a common practice on transmission lines, it is not common for gathering lines and interrupted surveys on gathering systems could lead to skewed data resulting from overlapping CP systems.

CIS is only one of several methods used in the industry to delineate areas of CP deficiency. PHMSA should allow for additional methods to validate the absence of a corrosion threat. For example, examination of the annual inspection results and other routine inspections, such as inline inspection, would provide an indication that a deficiency exists. Further, often a low CIS reading does not prove that there will be active corrosion and a high reading does not always mean that no corrosion is present due to shielding or other issues.

Making the use of CIS mandatory to delineate areas of deficient CP would impose significant costs to industry that may not be warranted in all situations and provide minimal benefits. Existing law requires the generation of a very large amount of CP data over the course of any year. Operators, and the Agency, review that data to identify CP deficiencies and plan appropriate remediation. Mandating the generation of additional and costly data may be wholly

unnecessary, as existing data already clearly shows the type and extent of any CP problem. A new CIS requirement could actually delay remediation plans and schedules in many instances.

PHMSA has historically interpreted the requirement to remediate CP deficiencies “promptly” to mean ‘before the next test interval.’ If PHMSA does add a mandatory CIS requirement for any annual CP test data deficiency, the Agency should at least provide operators with 15 months to complete the associated remediation, for the simple fact that existing law allows annual CP tests to be conducted ‘no later than 15 months’ apart. If finalized, this new regulation would require operators to conduct a CIS before they could begin remediation, even in those instances where the appropriate remediation was already identified. API recommends deleting the requirement to confirm adequate CP by CIS over the entire area as this could delay the remediation itself. Thus, proposed §192.465(d) and § 192.465(f) should be revised as follows:

§ 192.465(d) and (f) External corrosion control: Monitoring.

- (d) Each operator must promptly correct any deficiencies indicated by the inspection and testing provided in paragraphs (a), (b) and (c) of this section. Remedial action must be completed promptly, but no later than the next monitoring interval in § 192.465 ~~or within one year~~, **not to exceed 15 months**, whichever is less.

* * * * *

- (f) For onshore transmission lines, where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in Appendix D of this part, the operator must determine the extent of the area with inadequate cathodic protection. Close interval surveys must be conducted in both directions from the test station with a low cathodic protection (CP) reading at a minimum of approximately five foot intervals. Close interval surveys must be conducted, where practical based upon geographical, technical, or safety reasons. Close interval surveys required by this part must be completed with the protective current interrupted unless it is impractical to do so for technical or safety reasons. Remediation of areas with insufficient cathodic protection levels or areas where protective current is found to be leaving the pipeline must be performed in accordance with paragraph (d) of this section. ~~The operator must confirm restoration of adequate cathodic protection by close interval survey over the entire area.~~

2. New Post Construction Coating Surveys are Redundant

The NPRM proposes to add a new requirement for inspection and testing of transmission line coating at both the time of original construction of any line, and again any time 1,000 feet or more of line requires backfill after repair or replacement. *NPRM at 20829*. This new provision would be set forth at §192.319(d) and §192.461(f) with an additional parenthetical added to §192.461(a)(4) to clarify that operators have an obligation to maintain coating from handling or soil stress, “including but not limited to transportation, installation, boring, and backfilling.” *NPRM at 20829*.

API believes these new requirements are redundant and unnecessary. PHMSA does not provide any supporting evidence that backfilling a ditch for a steel onshore transmission pipeline is (or has been) an issue meriting the need for DCVG or ACVG surveys to assess coating integrity. Further, §192.319(a) already requires all operators of transmission gas pipelines to “protect the pipe coating from damage,” either in initial installation, or any time the pipe is exposed and backfill material is added. Similarly, §192.463 currently requires operators to provide adequate cathodic protection in a manner that protects the coating. In addition, existing regulations at

§192.465-192.473 require inspections, tests and monitoring to maintain adequate coating and cathodic protection, which vary from annual to every other month requirements.

While not discussed in the NPRM or Preliminary RIA, PHMSA recently proposed to extend the operator qualification (OQ) requirements in Subpart N to construction activities. *Notice of Proposed Rulemaking, 80 Fed. Reg. 39916 (Jun. 29, 2015)*. The OQ program requires pipeline operators to develop and implement a written program for qualification of individuals who perform covered tasks on a pipeline facility. In accomplishing that objective, operators must identify the covered tasks performed on their pipeline facilities; conduct appropriate periodic evaluations to verify that the individuals responsible for performing these tasks are qualified to do so; and maintain sufficient documentation to support these determinations.

If PHMSA's proposal to extend the OQ program to construction activities is adopted, personnel responsible for complying with the coating protection requirements in §192.319(a) must be qualified to perform those activities. Pipeline operators will also be required to conduct periodic evaluations to verify those qualifications and maintain associated documentation. The NPRM and Preliminary RIA fail to address the potential overlap and impact of the Agency's pending proposed rule to apply OQ requirements to those activities.

In addition, many pipeline operators already follow the corrosion control requirements in other industry standards to supplement the Part 192 regulations. Those industry standards, including Section 5 of NACE SP016-2013, contain comprehensive provisions for selecting, testing, evaluating, handling, storing, inspecting, and installing external coating. There is nothing in the record to suggest that such industry standards are inadequate, or that external corrosion would be more effectively managed if PHMSA implemented the changes proposed in the NPRM. Nor does the record make the demonstration required by law that adopting the corrosion control requirements in NACE SP016-2013 or other existing industry standards into Part 192, rather than the government-unique provisions offered in the NPRM, would be inconsistent with the requirements in the PSA or otherwise impracticable. *15 U.S.C. § 272 note, NTTA*.

For all of these reasons, plus the fact that incidents caused by corrosion have continued to decline and remain low over the past decade, API believes that the proposed additions to §192.319(d) and §192.461(f) are unnecessary and would require additional cost to industry that is not offset by public benefits.

If PHMSA does not delete the proposed rules at §192.319(d) and §192.461(f), API requests that PHMSA consider the following revisions to both rules:

- (1) PHMSA should take into account evolving technologies and allow for flexibility in the use of alternative survey methods (ILI current mapping).
- (2) Increase the assessment time frame for the DCVG or ACVG survey from three months to one year after placing the pipeline in service. Three months for a DCVG or ACVG survey is too restrictive because depending on when construction is finished, conditions might not allow for a DCVG or ACVG within

three months (frozen ground/bad weather) and time should be allowed for the backfill to adequately settle around the pipe.

- (3) Increase the minimum length of newly-installed pipe requiring a survey from 1,000 feet to 1 mile. Short replacement segments are more likely to be conducted by company crews and are less likely to be installed by typical long segment construction and installation methods. For shorter segments, it is also more likely that a more continuous inspection presence can be maintained.
- (4) Remove the severity limits requiring repair. Due to the lack of industry agreement on the significance of voltage drops in ACVG/DCVG surveys, severity limits were removed from the latest version (2010) of NACE SP0502 and likewise, severity limits are not referenced in the companion industry standard NACE TM0109.
- (5) Provide clarity on how the definition of an interruption. A clarification would be needed in any instance with respect to continuous segment, or interrupted segments, and how any interruption should be understood.

In addition, §192.461(a)(4) should be revised to provide for flexibility as follows:

§ 192.461(a)(4) External corrosion control: Protective coating.

“Have sufficient strength to resist damage due to handling (including but not limited to transportation, installation, boring, and backfilling) and soil stress as applicable; and,”

3. Requirements for New Interference Surveys and Response Should Follow Updated Industry Standards

The proposed new §192.473(c) does little more than add some examples of the type of situations where stray electrical currents may interfere with an individual steel pipeline. *NPRM at 20809-20810*. The proposed rule change would also require “prompt” remedial action to protect the pipeline from stray electrical current. “Prompt” in this instance is defined to mean “no later than six months after completion of the [stray electric current] survey,” but the rule does not specify when a survey should be completed. In short, the proposed rule would not change existing law significantly, but it would change existing practice, by suggesting without clarity that more operators should be conducting more electric stray current surveys more often. That result would be costly, with no benefit.

Existing §192.473 requires that operators have “a continuing program to minimize the detrimental effects of [stray] currents.” That requirement has been in place for 45 years. Over that period of time, the number of incidents caused by stray currents has been very low. Stray currents by their nature are site specific, and wholly dependent on outside actions (whether that be other pipelines, overhead power lines, new industry or equipment, etc.). Because such impacts are not uniformly distributed in space, nor do they occur on any predictable schedule, it is impossible for any rule to be useful if it becomes too specific. As written, the existing rule requires all operators to make sure their operation and maintenance (O&M) manual has a written

procedure to anticipate stray currents. Given how unpredictably stray currents occur, that generic requirement is appropriate, and operators do in fact conduct stray current surveys as a matter of course in implementation of their cathodic protection programs.

Most pipeline operators already follow industry standards to compliment the Part 192 regulations. For example, Section 9 of NACE SP016-2013, Control of External Corrosion on Underground or Submerged Metallic Piping Systems, contains comprehensive requirements that explain the mechanisms that cause stay-current corrosion, provide guidance on the methods for detecting stray currents, and identify the optimal methods for mitigating interference corrosion problems. There is nothing in the record to suggest that these standards are inadequate, or that stray currents would be more effectively detected, mitigated, or resolved if PHMSA implemented the changes proposed in the NPRM. Nor does the record make the required showing that incorporating the requirements in NACE SP016-2013 or other established industry standards by reference, rather than adopting the government-unique provisions offered in the NPRM, would be inconsistent with the requirements in the PSA or otherwise impracticable. PHMSA and NACE have provided guidance on how to isolate the source of stray currents and address the issues discovered. That guidance has been useful to the industry. PHMSA's proposed revisions to existing §192.473 are unnecessary, however, and will only lead to confusion in a topical area that is already well understood and adequately managed.

As such, API proposes the following revision to §192.473(c)(1) based on NACE SP0169-2013:

§ 192.473(c)(1) External corrosion control: Interference currents.

- ~~(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be taken on a periodic basis including, when there are current flow increases over pipeline segment grounding design, from any co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up rating, additional lines, new or enlarged power substations, new pipelines or other structures;~~
- (1) Interference surveys shall be conducted on a periodic basis where stray currents are suspected. The interference survey shall include the measurements of pipe to soil potentials at foreign cathodically protected structure crossings, areas affected by DC utilities, and other area likely to discharge interference currents. Alternating current interference should be considered. AC P/S potentials shall be measured and documented for pipelines in proximity to high voltage alternating current (HVAC) transmission utilities.**

4. Internal Corrosion Requirements Provide No Additional Benefit

The NPRM proposes to add new requirements to Part 192, Subpart I rules regarding control of internal corrosion on gas transmission pipelines. *NPRM at 20810*. Specific proposals include additional gas constituent monitoring under new proposed §192.478. Again, this appears to be a solution proposed where no problem exists. PHMSA existing regulations already clearly prohibit the transportation of corrosive gas unless investigated and addressed before transport (§192.475(a)) and require all operators to investigate and minimize internal corrosion whenever found (§192.475(b)). In addition, existing rules require consideration and avoidance of internal corrosion risks during construction and design of gas pipelines, and during replacements or repairs (§192.476).

Pipeline operators have an obvious interest in maintaining the quality of the product transported through their systems. Operators therefore investigate any indications of internal corrosion whenever they occur. The Agency's own data shows that internal corrosion is not a significant cause of pipeline incidents, further suggesting that existing rules and industry action are sufficient.

API respectfully submits that the addition of a new §192.478 would simply add more burden and cost to the industry, with no discernible benefit. In addition, as proposed this would apply to every well located on a system, which is excessive. The same purpose is served through annual gas analyses and could be supplemented by coupons or other preventive and mitigative measures. Further, internal corrosion requirements that work well in a transmission line setting are particularly impractical for gathering pipeline systems. Therefore, API requests that PHMSA remove the requirements for corrosive constituents.

5. Remedial Measures Limit Analytical Methods

The NPRM would also add additional requirements for determining remaining wall thickness under §192.485. *NPRM at 20830*. API requests that PHMSA provide for additional established analytical methods, consistent other Part 192 allowances for equivalent standards methodologies (e.g., existing §192.112, §192.907, and NPRM proposed §192.713(d)(1)(i)). Such methodologies could include the use of the well-recognized and widely accepted API-579, ASME fitness for service, finite element analysis, etc. In addition, API recommends that PHMSA delete the 80% wall thickness limitation as industry standards do not contain an explicit prohibition against using such methods at greater depths. Only the 2009 ASME B31G flow chart and calculations stopped at 80% and recommended repair or replacement at depths greater than 80%. Such a limitation, however, has not been part of the standard in 7 years. Further, API suggests that the undefined "reliable, traceable, and verifiable" records standard and a cross-reference to §192.607 are duplicative and redundant.

For those reasons, API requests that PHMSA revise the proposed revisions to §192.485 as follows:

§ 192.485 Remedial measures: Transmission lines.

- (c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, *see* § 192.7), ~~or~~ the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, *see* § 192.7), or a procedure using a similar established analytical method for corrosion defects. Such ~~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 prescribed limitations, ~~prescribed in the procedures, and including~~ the appropriate use of Class location and pipe longitudinal seam factors in pressure calculations for pipe defects. When determining the predicted failure pressure (PFP) for gouges, scrapes, selective seam weld corrosion, and crack-related defects, appropriate failure criteria must be used and justification of the criteria must be documented. Pipe and material properties used in remaining strength calculations and the pressure calculations made under this paragraph must be documented ~~in reliable, traceable, verifiable, and complete records. If such records are not available, pipe and material properties used in the remaining strength calculations must be based on properties determined and documented in accordance with § 192.607~~

D. Integrity Management Requirements are Too Prescriptive

In response to NTSB and GAO recommendations, PHMSA proposes various regulatory changes to the Part 192, Subpart O IM regulations. *NPRM at 20840-20848*. Many of these proposed changes, such as selection of assessment methods, repair conditions and repair criteria, move toward more prescriptive regulations. *Id.* IM regulations are built on the performance-based regulatory model which allows operators a variety of options to apply minimum safety standards to the specific characteristics of their pipeline systems. These regulations have been extremely successful in improving pipeline safety since their implementation in 2004.

Pipeline systems are complex and vary greatly from operator to operator and system to system. Current IM regulations provide operators with the flexibility to determine which methods are appropriate to meet minimum pipeline safety standards, while encouraging technological advancements. API agrees that there are improvements to be made under Subpart O, but cautions that prescriptive regulations can be rigid, inefficient and discourage technological improvement. For those reasons, API and its members strongly support continued reliance on the current performance-based regulatory scheme because it is essential to improving pipeline safety and advancing pipeline technologies.

In light of the above, API recommends that PHMSA's proposal be revised to include necessary phase-in timeframes for implementation of various additional data considerations and validation requirements, allow operators additional options and flexibility to avoid otherwise rigid and impractical requirements, and clarify vague proposed language.

1. Expansion of Data Integration/Risk Assessment Requires Phase-In Period

The NPRM expressly lists a minimum of 36 data attributes that operators must integrate for every pipeline, some with numerous subparts. *NPRM at 20840-20841*. These attributes are largely borrowed from ASME B31.8S, Section 4 Table 1 and Appendix A, which are currently incorporated by reference under §192.917, but PHMSA's list is more detailed and includes additional attributes. While collection and integration of the majority of these inputs should not be a major burden for the industry, this proposal would require their collection and analysis on covered and non-covered segments. In addition, some data attributes may not be available or feasible to obtain for all any in-service pipeline segments, for example hardness, Charpy toughness and chemical composition.

PHMSA revises § 192.917(a) which outlines the threat categories that an operator must consider based on ASME B31.8S, Section 2. *NPRM at 20841*. The Agency does not accurately describe them consistent with ASME B31.8S, however, by failing to include "human error" in the "time independent" threat category. Further, requirements under proposed §192.917(b)(2),(3), and (4) impose new requirements with respect to data integration with regard to additional analysis and validation. *NPRM at 20841*. First, the data must be "objective, traceable, verifiable and validated . . . to the maximum extent practicable" (including measures to correct subject matter bias if subject matter experts are referenced). *Id. (proposed §192.917(b)(2))*. Documentation of the subject matter experts and information they submit must be maintained for the life of the pipeline. *Id.* The data analysis must identify and analyze spatial relationships among anomalous information (storing information in a common location like GIS is not sufficient). *Id. (proposed*

§192.917(b)(3)). In addition, it must also be analyzed for interrelationships among pipeline integrity threats. *Id.* (proposed §192.917(b)(4)). Similarly with respect to risk assessments, PHMSA proposes requiring additional considerations (e.g., interacting threats) and validation of those threats. *NPRM at 20841* (proposed §192.917(c)).

API agrees that accurate data integration is essential to an effective integrity management program. The language proposed in the NPRM, however, is unattainable in practice and should be modified. Existing integrity management regulations that incorporate ASME B31.8S, Section 12, Quality Assurance requirements (at 49 C.F.R. §192.911(l)) already necessitate documentation control, a quality control plan, and monitoring of the effectiveness of that plan. Further, this proposal goes far beyond the NTSB Recommendation P-11-18 that PHMSA relies upon to justify this change, which simply stated (in relevant part) “[d]evelop and implement standards for integrity management [...] that require operators of all types of pipeline systems to regularly assess the effectiveness of their programs using clear and meaningful metrics, and to identify and then correct deficiencies.” *NPRM at 20760*. There is no reference to “bias control.”

An operator’s subject matter experts are typically the most knowledgeable and experienced persons when it comes to an operator’s system. As such, they are often the most valuable tools in identifying integrity threats. If the rule includes a standard to correct subject bias, at a minimum PHMSA should define bias so that it is an objective standard which cannot ultimately discount a person’s knowledge or experience. By way of illustration, Merriam-Webster defines ‘bias’ in a variety of ways from bent or tendency to a deviation in expected statistics to a systematic error. Further, requiring documentation of the names of all SMEs can have the unintended consequence of inhibiting the free exchange of ideas. As an alternative, API recommends that PHMSA require a second process step where an independent reviewer checks and validates the checklists submitted by each SME and resolves conflicts.

Throughout §192.917, and particularly in §192.917(b)(4) §192.917(c), PHMSA appears to require, without expressly stating it, a quantitative risk assessment (also referred to as a quantitative or probabilistic risk model). In particular, proposed §§192.917(c)(1-5) can only be satisfied through quantitative or probabilistic risk models. Just this year, PHMSA convened a working group to analyze various risk models and develop a technical guidance document on risk modeling. See *PHMSA Risk Modeling Working Group*, at <https://primis.phmsa.dot.gov/rmwg/index.htm>. It is premature and inefficient to require that operators implement one type of risk model until this effort is complete and the guidance is finalized. Qualitative risk assessment models are a useful tool for operators when analyzing frequently occurring events and phenomena, such as external corrosion and excavation damage, for which much statistically relevant data exist. These models are not useful or appropriate, however, for the analysis, prediction or prevention of the low frequency, high consequence events such as San Bruno. Such events typically require two or even more circumstances and conditions to converge at a single location and single time to produce the unwanted event. The probabilities of each of these occurring is so low that the quantitative or probabilistic models would not identify them because there are no statistics available from which to predict them. While these models are valuable, they are not likely to address or impact in any systematic manner the occurrence of low frequency, high consequence events.

In addition, PHMSA proposes several considerations that may be impossible to quantify and apply in practice. These include: (1) “evaluation of the effects of interacting threats, including the potential for interactions of threats and anomalous conditions not previously evaluated” and (2) validation that risk assessment methods produce a “risk characterization consistent with industry experience.” *NPRM at 20841 (proposed § 192.917(c)) (emphasis added)*. Further, it is not clear what PHMSA means by the phrase “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.” *Id.* For those reasons, API requests that PHMSA remove these considerations from the proposed rule and provide operators with the flexibility to use different risk models. At the very least, PHMSA should provide additional guidance and explanation.

Finally, these requirements will require operators to draft and implement many new operator procedures and conduct the analysis. This will require a period of time for operators to come into compliance. As drafted, however, operators would have to immediately comply with these requirements. API requests that PHMSA include a phase-in period for operators to incorporate these requirements into their Integrity Management Programs (IMP) for both data integration and risk assessments, and recommends a 5 year period for operators to implement them.

2. *Changes to Requirements for Certain Identified Threats Need Clarification*

The NPRM proposes additional criteria for cyclic fatigue, manufacturing and construction, and electric resistance welded (ERW) threats. *NPRM at 20842*. Advances in inspection detection technology have greatly improved the industry’s ability to detect and understand threats to pipeline integrity. Similarly, research on pipe metal strength and failure mechanics has broadened the industry’s ability to predict the safety of pipeline operations more accurately. These advances and research should guide any revisions to the criteria for cyclic fatigue, manufacturing and construction, and ERW integrity threats.

As proposed in the NPRM, if an operator identifies cyclic fatigue as a threat, it must perform annual fatigue analyses, not to exceed 15 months. *NPRM at 20842*. API believes that annual fatigue analyses are not necessary and requests that PHMSA consider revising this language to require updated fatigue analyses based on changed operating conditions, but not to exceed in conjunction with every IM reassessment.

With respect to manufacturing and construction defects, PHMSA would increase the threshold requirements for considering the stability of those defects where (1) a Subpart J hydrostatic test has been performed to 1.25 MAOP and (2) the segment has not experienced an in-service incident attributed to a manufacturing or construction defect since the date of that test. *NPRM at 20842 (proposed §192.917(e)(3))*. If certain operational changes occur, an operator must prioritize the segment as high risk and reestablish MAOP. API agrees that if a pipeline has an unstable manufacturing and construction defect, it should be prioritized as high risk for reassessment. API questions, however, the Agency’s justification for requiring an operator to reestablish MAOP. Existing regulations are already adequate because they require that (1) operators limit MAOP based on the condition of the pipe (§192.619(a)(4)), (2) as the segment will be prioritized as high risk if a defect is unstable (existing §192.917(e)(3)), and (3) in the event of a pipeline incident or other integrity risk, existing regulations provide PHMSA with the

ability to control the conditions necessary for the restart of the pipeline (§190.233, §190.239). Further, it is not logical to assume that one manufacturing and construction defect would be applicable across the entire pipeline.

For ERW pipe threats, PHMSA proposes to clarify that seam failure as it relates to seam failure susceptibility includes but is not limited to “pipe body cracking, seam cracking, and selective seam weld corrosion” and requires that pipes with cracks be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth. *NPRM at 20842 (proposed §192.917(e)(4))*. Established industry research indicates that pipe body cracking and selective seam weld corrosion, however, are not specific to ERW pipe.²⁷ Pipe body cracking is not a seam failure type. API requests that PHMSA strike this language.

§192.917(e)(4) How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?, Actions to Address Particular Threats

(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 noncovered 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).

3. IM Assessments & Continual Evaluation

The NPRM proposes revisions to existing integrity management assessment methods as well as several new test methods, including spike testing, Guided Wave Ultrasonic Testing (GWUT) and excavation and in situ examination. *NPRM at 20842*. API and its members commend PHMSA for clarifying existing assessment methods and for proposing additional methods. That said, the Agency’s proposal includes too many prescriptive requirements that will limit operators to certain methods and stifle technological advances. In addition, operators should not be restricted

²⁷ See e.g., Leis & Nestleroth, *Battelle’s Experience with ERW and Flash Weld Seam Failures: Causes and Implications* p. 11 (Sep. 2012) (*Battelle Report*). The Battelle report discusses selective seam corrosion (SSC) and other defects, noting that “Because the focus here is on seam defects in pre-1970s ERW and FW pipes, the images and discussion that follow next are specific to such pipe. But as defects continue to occur in more recent pipe made using the HFI and HFERW processes, such defects will be considered later in a section that contrasts HFERW pipe to its LFERW predecessor” and later concludes with respect to SCC that “one can infer that the underlying mechanism remains ill-defined, with the possibility being that more than one mechanism is responsible, depending on the local circumstances.” *Id.*; see also Brossia, *Selective Seam Weld Corrosion Literature Review*, DNV Report to PHMSA (Apr. 2012) (cited in *Battelle Report* pp. 16-17) (explaining the mechanisms proposed to explain why SSC occurs and noting other work which reports a propensity for SSC absent local evidence of sulfides). In addition, the CEPA Stress Corrosion Cracking Recommended Practice explains that “SCC-related service incidents and hydrotest failures have been associated with longitudinal DSAW and ERW long seams, but SCC has also been detected in DSAW spiral, seamless and flash butt-type long seams.” *CEPA Stress Corrosion Cracking RP-2007, Section 5.1.1.2, p. 5-4*. It is also notable that planned revisions of API RP 1160 and 1163 will address the existing gaps regarding SCC relevant to liquid pipelines.

to the approved PHMSA assessment methods. For that reason, PHMSA's proposal should be clarified and revised as outlined below.

As a general comment, similar to the Agency's non-HCA assessment proposal, the proposed revisions to IM assessment regulations would require operators to "apply one of more of the following methods for each threat to which the covered segment is susceptible." *NPRM at 20842 (revised §192.921(a))*. API requests that PHMSA clarify this revision as it suggests that at least 1 assessment may be required for each threat to which a pipeline may be susceptible.

a. Baseline Assessment Methods

With respect to assessment performed by ILI, API requests that PHMSA clarify that every ILI assessment does not require a crack tool and that tools are driven by the identified threats under §192.921(a)(1) and §192.937(c)(1). Operators should be able to run the appropriate ILI tools for the threats that are known or likely to exist on the pipeline. In addition, PHMSA has added reference to "girth weld cracks" to the list of crack defects under revised §192.921(a)(1). There are no tools designed to find girth weld cracks and most incidents caused by girth weld crack have of third party excavation damage as a contributing factor. This is a threat that is best handled by procedures that require caution around girth welds during excavation and backfilling procedures. Further, including girth welds is not consistent with Agency's proposed hazardous liquid rule. PHMSA's proposed language under §192.921(a)(1) (to require that a person "qualified by knowledge, training, and experience analyze ILI data") is duplicative and confusing in light of existing operator qualification regulations under IM at §192.915 and proposed revisions to §192.493 incorporating industry ANSI standard on ILI personnel qualification.²⁸ *NPRM at 20842*. For those reasons, API requests that the reference to "girth welds" and qualifications be deleted from the proposed regulation. In addition, API requests that PHMSA delete the reference to obtaining a "no objection letter" from the PHMSA Associate Administrator because there is no established procedure for such letters and adding a new process that is not articulated in the rules or well-defined would cause further confusion.

Regarding proposed revisions to the "other technology" method, as discussed in Section III.D.3, API believes that it is not appropriate to reference a "no-objection letter" from the Associate Administrator. PHMSA enforcement procedures and regulatory procedures in Part 190 do not provide for such letters, the reference to Associate Administrator is likewise without precedent or justification, and such a requirement is inconsistent with the proposed hazardous liquid rule which contains no similar requirement. Further, PHMSA does not articulate a timeframe for its decision.

As discussed above, API requests the following changes to §192.921:

§ 192.921, How is the baseline assessment to be conducted?

- (a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods ~~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

²⁸ As a general matter, API supports incorporation by reference of industry standards that are up to date, as opposed to incorporating standards that are already outdated.

the threats identified to the covered segment, which may include one or more of the following methods. (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, or, if indicated as a threat by the historical data of the pipeline 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.~~ deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (including stress corrosion cracking, selective seam weld corrosion, and environmentally assisted cracking, ~~and girth weld cracks~~), hard spots with cracking, and/or any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493. ~~A person qualified by knowledge, training, and experience must analyze the data obtained from an internal inspection tool to determine if a condition could adversely affect the safe operation of the pipeline. In addition, an operator must explicitly consider uncertainties in reported results (including, but not limited to, tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;~~
- (7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with § 192.949 ~~and receive a “no objection letter” from the Associate Administrator of Pipeline Safety.~~ An operator must also notify the appropriate State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

With regard to the methods for pressure testing and spike testing (discussed more fully below), PHMSA includes express language that identifies which threats these tests may evaluate (i.e., “are appropriate for”). While such language may be helpful, it should be driven by industry standards and should not limit operators from using a certain method without justification.

Finally, PHMSA’s proposal greatly limits an operator’s ability to use methods of direct assessment, such as internal corrosion direct assessment (ICDA) and stress corrosion cracking direct assessment (SCCDA), where a line is (1) not capable of inspection of internal inspection tools and (2) it is not practical to assess the line using other methods. *NPRM at 20843-20845*. These methods have proven successful in targeting threats of external corrosion, internal corrosion and stress corrosion cracking. While API commends the Agency on providing necessary clarifications in the regulations on these assessment methods, operators should not be limited to using them where those threats are present.

Further, operators should not be restricted under proposed changes to §192.923, §192.927, and §192.929 to performing these assessments by the methods proposed in the NPRM. Those methods while purporting to rely on NACE standards contradict those standards in certain places and exceed them. The Agency is essentially making assessment requirements so stringent in order to force operators to make lines smart piggable. API supports NACE standards SP0206-2006 for ICDA and SP0204-2008 for SCCDA, but PHMSA should not exceed those established industry standards. Any changes to those established methods for direct assessment should be addressed through NACE committees (not PHMSA). Further, where PHMSA incorporates

industry standards, the Agency should incorporate by reference the most up to date standards (discussed below).

b. Spike Testing

As a new method, PHMSA would also allow “spike” hydrostatic pressure testing performed pursuant to a new provision at §192.506. *NPRM at 20830, 20842*. PHMSA clarifies that this method is appropriate for threats such as SCC, SSWC, manufacturing and construction defects, including defective pipe and pipe seams, and “other forms of defect damage or damage involving crack or crack-like defects.” *Id. at 20842*. PHMSA also clarified during a recent series of webinars that the Agency does not intend to apply the spike test requirement to gathering line operators.

The following minimum requirements should be targeted for a spike hydrostatic test as outlined in forthcoming *PRCI Guidelines for Use of Hydrostatic Testing as an Integrity Management Tool, PRCI Project - IM-3E, Contract - PR-430-153706*:

“A test pressure level at or above that of a high pressure test (defined in document as a test undertaken at pressures potentially greater than necessary for qualifying test minimum requirements in order to address or assess for an identified or targeted pipeline threat), and

Test pressure established based upon the target integrity threat and an estimate of the continuing deterioration rates to ensure reliable future operations.

A test pressure level at least equal to the minimum required mill test pressure based on the mill test requirements at the time of manufacture of the line pipe. If mill test pressures are unknown or unavailable, applicable minimums required by the API-5L or API 5LX version at the time of pipe installation can be used.

Note: There is no upper limit to spike test pressure levels; however, test pressure levels which greatly exceed historical mill test pressures or 100-percent SMYS must be carefully considered and the benefits should outweigh the potential detrimental effects.”

API, along with AGA and INGAA, fundamentally disagrees with PHMSA’s proposed 30-minute timeline for the “spike.” API supports AGA’s comments that “A 30-minute period is not substantiated by current research and is not reasoned nor justified; further, it has the potential to cause latent defects that are the exact opposite of PHMSA’s intent.” In a report commissioned by PHMSA’s predecessor agency to inform pipeline safety inspectors in evaluating the integrity management program, industry experts conclude that “the most important consideration is attaining the highest possible test pressure even if for only a few minutes. This philosophy is apparent in ASME B31.8S, *Managing System Integrity of Gas Pipelines*, which specifies a 10-minute hold time when testing for SCC.”²⁹ In 2013 industry experts explained that, “The idea is to test as high a pressure level as possible, but to hold it only for a short time (5 minutes is good

²⁹ Kiefner & Associates & Baker, *Spike Hydrostatic Test Evaluation*, TTO No. 6, Integrity Management Program Delivery Order DTRS56-02-D-70036, p. 1 (Jul. 2004).

enough).”³⁰ References to 30 minutes in both papers is used as an absolute maximum for the spike pressure, and not a minimum requirement.

In addition, API requests that PHMSA delete the reference to obtaining a “no objection letter” from the PHMSA Associate Administrator. PHMSA enforcement and regulatory procedures do not provide for such letters and adding a new process that is not articulated in the rules or well-defined would cause even more confusion.

For those reasons, in conjunction with AGA and INGAA, API requests that PHMSA revise §192.506(e) to a 10-minute spike.

§ 192.506(e) Transmission lines: Spike hydrostatic pressure test for existing steel pipe with integrity threats.

After the test pressure stabilizes at the baseline pressure and within the first two hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.50 times MAOP or 105% SMYS. This spike hydrostatic pressure test must be held for at least ~~30~~ 10 minutes.

4. Appendix F – GWUT Procedures

While API appreciates PHMSA’s proposed incorporation of GWUT procedures as an Appendix to Part 192, there are a few minor differences between the proposed regulation and the current procedures that require comment. In proposed Appendix F use of both torsional and longitudinal signal is required, but the extent that each type must be used is not clear. GWUT would become impractical in most cases if both signals are required on the entire segment because the longitudinal signal cannot be used on buried segments. Current industry practice employs the longitudinal signal only to spot check the exposed areas where the collar is installed. In addition, the prohibition on assessing shorted cases is confusing and contradicted by subsequent language which allows an operator to use GWUT on shorted casings if the only effect is a dampening of the signal. To clarify use of the longitudinal signal and retain precautions against certain uses of GWUT on shorted casings, API proposes the following revisions to Appendix F:

Appendix F, Criteria for Conducting Integrity Assessments Using GWUT

VI. Signal or Wave Type: Torsional and Longitudinal. Both torsional and longitudinal waves must be used in the course of the assessment and use must be documented. In most cases torsional wave will be used for the majority of the assessment and be complemented by longitudinal wave in the areas of the collar. The assessment should be designed to advantage the strengths of each wave type.

XVI. Use on Shorted Casings (direct or electrolytic): ~~GWUT may not be used to assess shorted casings.~~ GWUT operators must have operations and maintenance procedures (*see* § 192.605) to address the effect of shorted casings on the GWUT signal. The equipment operator must clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures. All shorted casings found while conducting GWUT inspections must be addressed by the operator’s standard operating procedures.

5. Response and Repair Criteria

³⁰ Kiefner & Maxey, *The Benefits and Limitations of Hydrostatic Testing*, p. 9 (2013).

The NPRM proposes revised stringent integrity management response and repair criteria that limit an operator's ability to expeditiously and appropriately respond to integrity issues. PHMSA proposes requiring operators to notify PHMSA when they are unable to discover conditions within 180 days of the integrity assessment and provide a date when adequate information will become available. *NPRM at 20845-20846*. Notably, the current 180-day timeframe is already compressed for many pipeline operators due to data integration and tool validation requirements and will be much more so if PHMSA's above proposed changes are implemented. In light of those proposals, API requests that PHMSA consider specifically what is impracticable under the 180-day time frame under §192.933(b). In addition, API requests that PHMSA include a timeframe for operators to submit this notification under the regulations, such as 30 days from the 180-day deadline.

API requests that PHMSA adjust the language under §192.933(b) to allow time for the operator and vendor to agree upon the quality of the data collected to make an accurate assessment of the condition of the pipe. Additional time is needed in order for the vendor to download the data and confirm the completeness of the data. If the dataset is not complete, the operator and vendor need time to confirm whether or not the data is adequate enough to make an assessment. The time period of 180 days should start once the integrity assessment is deemed acceptable.

§ 192.933 What actions must be taken to address integrity issues

- (b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days ~~after conducting an integrity assessment,~~ after confirming that the integrity assessment is acceptable, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period the operator must notify OPS, in accordance with § 192.949, and provide an expected date when adequate information will become available.

PHMSA's proposals for HCA repair criteria mirror that of non-HCA criteria, except that for HCAs two year conditions are one year conditions. *NPRM at 20845*. PHMSA's proposal, as drafted would require that operators expend resources on costly digs where immediate threats to pipeline integrity are not present. In addition, PHMSA's proposal should reflect industry research on fracture mechanics and metallurgy. For those reasons, API requests that PHMSA incorporate its proposed revisions in Section III.B.2. at a *new* provision under §192.933(d)(1)(i) as follows:

- (1) In calculating a predicted burst pressure for the purposes of determining remaining strength, selection of a suitable calculation method depends on several factors, including the failure mode of the anomaly. Appropriate calculation methods include, but are not limited to:**
- (i) For metal loss anomalies susceptible to failure in plastic collapse: ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (2012) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989));**

- (ii) For crack anomalies or selective seam weld corrosion (SSWC) associated with EFW and vintage ERW seams susceptible to failure through fracture: the Battelle Model (Modified Log-Secant), CorLAST™ or API 579 Part 9;
 - (iii) For dent anomalies: the safe working pressure can be determined using PRCI PR-218-063505 “Safe Inspection Procedures for Dent and Gouge Damage” (2010).
- (2) For purposes of this section, a likely crack is defined as having a reasonable degree of confidence that the anomaly called by the ILI vendor correlates to a crack defect. This can be the case where the operator’s previous experience on the present pipeline segment or other similar pipeline segment has found cracks or the case where the data integration indicates a strong likelihood that cracks could exist even though no historical data suggests so. A possible crack is defined as having a reduced certainty of being an actual crack and, when it is a crack, it occurs under different circumstances or the operator cannot determine with a high degree of confidence that the indication is not a crack defect.
- (3) For purposes of this regulation, an engineering analysis must include operator documentation and provide adequate technical justification for not completing repair or remediation of identified conditions within the specified timeframe. All evaluations must be performed by qualified persons, be based on sound engineering principles, and must account for the following factors at a minimum:
- (i) Metal loss: predicted flaw dimensions, material properties, tool tolerance, failure mode, and predicted growth rate
 - (ii) Crack indications: predicted flaw dimensions, material properties, tool tolerance, failure mode, operational pressure cycles, and predicted growth rate
 - (iii) Dents: predicted flaw dimensions, material properties, tool tolerance, failure mode, operational pressure cycles, and predicted growth rate of corrosion and/or cracks.

API agrees with PHMSA in §192.933(b) that ASME B31.8S should be applied for remediation based decisions. However, PHMSA suggests contradictory approaches by also requiring depth based criteria (% of nominal wall thickness) in subsequent proposed revisions to the regulation. PHMSA should only reference ASME B31.8S, which is considered the best accepted practice.

6. Immediate Repair Conditions

With respect to immediate repair conditions and remaining strength calculations, PHMSA would require an immediate repair where the remaining strength shows a predicted failure pressure less than or equal to 1.1 time MAOP at the anomaly location. *NPRM at 20845-20846*. This calculation must be based on ASME B31G or RSTRENG or, as proposed, an alternative equivalent method of remaining strength calculation “that will provide an equally conservative result.” *Id.* This calculation must be based on “reliable, traceable, verifiable and complete” records, and if an operator’s records do not meet this standard, pipe and material properties must be based on properties determined in §192.607.

As explained in Section III.B.2, API submits that requiring operators to comply with §192.607 for pipe and material properties is overly conservative (if grade A pipe is assumed) or burdensome (if proposed §192.607 requirements are followed) relative to the safety benefits conferred. API therefore proposes several changes to §192.933(d)(1)(d), that would allow operators options for calculating reduced pressure and that would eliminate the proposed

reference to the undefined “reliable, traceable, verifiable, and complete” standard for material documentation and the verification process set forth in proposed §192.607.

The requirements set forth under immediate repair conditions are consistent with the guidance in ASME B31.8S, which is in general, a standard for managing system integrity. Therefore, the calculation by nature is a rupture calculation, not a leak calculation. The language should be corrected accordingly by deleting “pressure” and replacing it with “**burst**.” As written, the requirements under immediate repair conditions do not leave operators with any flexibility on a segment of pipe if an operator is unable to confirm RTVC or determine properties through the §192.607 process. This is particularly problematic when attempting to determine or address an immediate repair feature. Operators are on a specific time schedule for integrity assessments. There is no alternative provided for completion of an assessment prior to completion of the requirements in §192.607.

Further, PHMSA’s use of “equally conservative” is a subjective standard that could be subject to varying interpretation. Alternative calculation methods, which can provide valid and sufficient safety margins, also provide different results. This requirement should be deleted as it is confusing and overly complicated. Although PHMSA did not propose any adjustments to dents in §192.933(c)(1)(ii), the language should be modified to be consistent with API’s proposed changes in §192.713. In addition, API requests that PHMSA provide the operator with some flexibility to address metal loss and in particular, API proposes to treat metal loss in a similar manner to a Grade 2 leak (actual leak) on a distribution system. With regard to PHMSA’s proposed addition of an immediate dent with any indication of metal loss along the longitudinal seam, API is not aware of data or research, including the numerous reports published from the PHMSA ERW study, that justify this requirement. *See e.g., Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase I, Battelle (Oct. 23, 2013).*

In light of the above, and consistent with API’s comments in Section III.B.2, API suggests the following changes to immediate repair conditions:

§ 192.933(d)(1) What actions must be taken to address integrity issues, Immediate repairs.

- (1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:
 - (ii) A calculation of the remaining strength of the pipe shows a predicted failure ~~pressure~~**burst** 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 (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. ~~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. The operator must document the basis for pipe and material properties used in remaining strength calculations.~~

- (iii) A dent that has any indication of ~~metal loss, a gouge, cracking, or a~~ stress riser unless an engineering analysis shows that it poses minimal risk to pipeline integrity.
- (iv) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.
- (v) Metal loss greater than 80% of nominal wall regardless of dimensions unless inspection data and analysis demonstrates minimal to no corrosion growth such that a leak is unlikely within one year.
- (vi) An indication of metal-loss preferentially 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)~~ Likely crack anomalies greater than 70% of nominal wall or of an indeterminate depth regardless of dimensions or the maximum depth sizing capabilities of the tool, as set forth in the vendor's performance specification, where the depth cannot otherwise be established through correlation with prior ILI runs.

7. One-Year Conditions

For the reasons discussed in Section III.B.2, API suggests the following changes to one year conditions:

§ 192.933(d)(2) What actions must be taken to address integrity issues, One-year conditions.

- (2) *One-year conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate 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 2/3 of the pipe) for which engineering analyses of the dent demonstrate critical strain levels have been exceeded or, if such a strain determination is not made,~~ 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) unless engineering analysis shows that it poses a minimal risk to pipeline integrity.
 - (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 detected longitudinal or helical (spiral) seam weld.
 - (iii) A calculation of the remaining strength of the pipe shows a predicted failure pressure ratio at the location of the metal loss or likely or possible crack ~~of the~~ anomaly less than or equal to 1.25 for Class 1 locations, 1.39 for Class 2 locations, 1.67 for Class 3 locations, and 2.00 for Class 4 locations.
 - ~~(iv) —An area of general corrosion with a predicted metal loss greater than 50% of nominal wall~~
 - (iv) 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 or general corrosion, or is in an area that ~~could~~ preferentially affects girth weld or exhibits SCC or SSWC.
 - (v) A gouge or groove greater than 12.5% of nominal wall.
 - (vi) Metal loss greater than 80% of nominal wall regardless of dimensions, that did not require an immediate response under 192.933 (c)(1)(iv).
 - ~~(vii) —Any indication of crack or crack-like defect other than an immediate condition.~~

8. Monitored Conditions

To provide for additional clarity, API suggests that PHMSA consolidate and streamline the description of dents that qualify as monitored conditions as follows:

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

- (3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:
 - (i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located ~~between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe)~~ anywhere on the pipe for which engineering analyses of the dent demonstrate critical strain levels are not exceeded and there are no additional exacerbating factors, such as gouges or other stress risers.
 - (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~~

9. Expansion of P&M Measures

The NPRM proposal sets forth eight new preventive and mitigative (P&M) measures to the existing six P&M measures that are required for pipelines located in HCAs. *NPRM at 20846.* With these changes, PHMSA would remove language which clarifies that an operator must base P&M measures on the threats an operator has identified to each pipeline segment. *NPRM at 20846.* As proposed, § 192.935(a) would appear to require that operators undertake all 14 P&M measures (including pipe replacement). To clarify that the list of P&M measures are options for operators to employ based on the particular threat, API requests that PHMSA reinstate the sentence in the existing regulation stating “**An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917).**”

It appears that PHMSA intended to consider additional measures when conducting a risk analysis, but as drafted, it is impracticable and potentially drastically revises the meaning of an integrity risk analysis under these rules. It could potentially require operators at great expense to dig up the entirety of a line to perform risk assessment/analysis and determine which integrity method should be implemented. As such, API proposes revisions below that are consistent with what operators are already doing. As an additional concern, the language regarding “installing pressure transmitter on both sides of [ASV] or remote control valves that communicate with pipeline control center” may force some operators who currently may not have a control center into the control room management regulations.

Therefore, API proposes the following changes to §192.935:

§ 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 may include, but are not limited to,**—correction of the root causes of past incidents to prevent recurrence; establishing and implementing adequate operations and maintenance processes that could increase safety; establishing and deploying adequate resources for successful execution of preventive and mitigative measures; installing Automatic Shut-off Valves or Remote Control Valves; installing pressure transmitters on both sides of automatic shut-

off valves and remote control valves that communicate with the pipeline control center; installing computerized monitoring and leak detection systems; replacing pipe segments with pipe of heavier wall thickness or higher strength; conducting additional right-of-way patrols; conducting pressure hydrostatic tests in areas where material has quality issues or lost records; tests to determine material ~~mechanical and chemical~~ properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations including material property tests from removed pipe that is representative of the in-service pipeline; re-coating of damaged, poorly performing or disbonded coatings; applying additional depth-of-cover survey at roads, streams and rivers; remediating inadequate depth-of-cover; providing additional training to personnel on response procedures, conducting drills with local emergency responders; and implementing additional inspection and maintenance programs.

In addition, in conjunction with the directive from Congress under Section 29 of the 2011 amendments to the PSA, PHMSA proposes to include explicit references to seismicity in the list of risk factors that must be considered in threat identification (§192.917(a)(3)), data integration (§192.917(b)(1)(xxxv)), and implementing P&M measures (§192.935(b)(2)). API does not object to the measures listed, but the language as written implied that an operator must take all of the actions listed. As such, API suggests the following changes in order to provide for optional consideration:

**§ 192.935(b)(2) What additional preventive and mitigative measures must an operator take?,
Outside force damage**

- (+) *Outside force damage.* If an operator determines that outside force (*e.g.*, earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must ~~take-consider~~ measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, conducting appropriate in-line or geotechnical inspections, and-or relocating the line., ~~or, GIS, and deformation in-line inspections.~~

The NTSB's Safety Study which prompted many of the proposals to improve natural gas IM regulations found that existing IM requirements have reduced potential incidents due to corrosion (among other issues), and "kept the rate of corrosion failures [...] low" and "appear to be effective." *NTSB Safety Study, IM Gas Transmission Pipelines in HCAs, NTSB SS 15/01 (Jan 27, 2015); see also NPRM at 20729 (citing the study and noting that same about reducing corrosion incidents).* The NPRM proposes new extensive P&M measures for internal and external corrosion at §192.935(f) and §192.935(g). *NPRM at 20846-20847.* All operators would be required to enhance their corrosion control programs with respect "to a covered segment," to include periodic close internal surveys, coating surveys, interference surveys, and gas quality monitoring inside HCAs and minimum performance standards for that testing. Where threats of internal and external corrosion are present on pipelines, some of these additional measures may be justified depending on the circumstances.

The NPRM would require extensive expansion of programs that in most cases are already effective. API believes that existing corrosion control P&M measures that operators are implementing are sufficient and PHMSA's proposed requirements under §192.935 may result in diverting resources from higher risk pipeline integrity issues in HCAs. It is inconsistent to include such prescriptive requirements in the IM rules that are not found in Subpart I. API therefore urges PHMSA to strike §192.935(f) and §192.935(g). API is concerned that requiring

all of these extra measures on potentially all HCA pipelines is costly and duplicative of existing corrosion control monitoring performed under Subpart I.

Should PHMSA retain requirements such as proposed in (f) and (g), API proposes numerous clarifications. With regard to internal corrosion requirement to address corrosive gas stream constituents over a 24-hour period is completely arbitrary. Instead, API believes that it is best to consider the characteristics of an operator's line and whether there is a slight exceedance from a one-time event or a longer term problem. The requirement to limit carbon dioxide to 3% volume is too prescriptive because the percent varies by the pressure in the pipeline. API recommends adding an "or" because carbon dioxide is not usually a problem unless the gas contains water. In addition, the proposed rule does not clarify the measurement of the hydrogen sulfide limitation (ppmV or ppmW) or even why this is the limit. This is also not usually a problem unless water is present.

With regard to external corrosion control, CP and CIS surveys contemplates a coating with holidays and provide for protection of a pipeline with a less than perfect coating against external corrosion. While a DCVG survey may be useful to the operator in assessing damaged coatings, the periodic performance of such a survey is not required in order to assure adequate protection against external corrosion. Further, DVCVG does not assess the adequacy of cathodic protection. As drafted, the proposal could require CIS surveys at every turn, which typically require 3 men to walk the line and cost up to \$2,000 per mile. API believes that the appropriate considerations should be limited to: electrical interference currents, adequacy of coating (using indirect assessment), and adequacy of cathodic protection Data integration requirement should be deleted as duplicative.

The above proposed revisions are outlined below:

§ 192.935(f) and (g) What additional preventive and mitigative measures must an operator take?, Internal corrosion and External corrosion

- (f) *Internal corrosion.* As an operator gains information about internal corrosion on a covered segment, it must evaluate the effectiveness of the internal corrosion management program enhance as required under subpart I of this part, and implement appropriate changes to that its 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 evaluation enhancement, operators should must consider—
- (1) 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~~ 7 psi partial pressure per CO₂ or;
 - (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, If hydrogen sulfide cannot be limited and water is present in the stream consider implementation of~~ a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.
 - (2) Review the program at least semi-annually based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.
- (g) *External corrosion.* As an operator gains information about external corrosion on a covered segment,

it must ~~evaluate enhance—the effectiveness of the~~ its external corrosion management program, as required under subpart I of this part, and implement appropriate changes to that program, 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 ~~evaluation enhancement~~, operators ~~should must consider~~—

- (2) 1. electrical interference currents that can adversely affect cathodic protection as follows:
- (3) the adequacy of external corrosion control through indirect assessment as follows:
- (i) ~~Periodically (as frequently as needed but at intervals not to exceed seven years) assess the adequacy of the cathodic protection through an indirect method such as close interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG).~~
- (ii) ~~Remediate any damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dB_{uv} for ACVG) under section 4 of NACE RP0502 2008 (incorporated by reference, see § 192.7).~~

IV. Other

API requests that PHMSA consider the following comments on various other proposed PHMSA changes outlined below. In particular, PHMSA's proposal to require that all transmission pipelines develop and follow management of change (MOC) policies requires a phase-in period for implementation, various proposed definitions not outlined above warrant revisions and/or deletion, and other proposals such as the extension for reassessment intervals and integrity management MOC proposals would benefit from clarifications. In addition, API expresses its support for other proposals or revisions, such as the MAOP exceedance reporting proposed regulations for transmission pipelines and the clarification to low stress reassessment requirements.

A. **Extreme Weather Events Requirements Need Clarifications and Definitions**

In response to pipeline incidents related to flooding at pipeline river crossings, PHMSA proposes to add a new § 192.613(c) to require onshore transmission operators to inspect pipelines within 72 hours of cessation of an “extreme weather event” and to take certain remedial actions to verify pipeline safety. *NPRM at 20832*. This proposal is duplicative of existing legal requirements under § 192.605(e) and § 192.615, which require a prompt and effective response to emergency issues, including natural disasters, emergency shutdowns and pressure reduction in any pipeline system necessary to minimize hazards to life or property, notice to local responders and public officials, as well as coordinating planned responses and actual responses. Additionally, API is concerned that the proposal does not contain sufficient clarity regarding the conditions that would require an inspection and in particular what would qualify as “other similar events.” The proposed addition to § 192.613 raises more questions than it answers and creates confusion relative to its relationship and overlap with the requirements of § 192.615. As currently drafted, the proposed regulations raise numerous questions, including:

- *What constitutes an “extreme weather event,” triggering the requirements of proposed § 192.613(c)?*
 - *The same or similar events in different geographic locations may have different impacts ranging from benign to severe.*
 - *The same event in a single location may have different impact on different operators ranging from benign to severe.*
- *Who decides whether an event triggers proposed § 192.613(c)?*
- *Given the precision of the requirement that inspections commence within “72 hours” after the cessation of the event, who decides and how exactly is it decided when the 72-hour clock starts?*

- *How does an operator prioritize needed inspections in order to meet the 72 hour deadline?*
- *What inspections must be performed?*
 - *If ILI, it will be virtually impossible to do within 72 hours by a single operator.*
 - *If a widespread event, ILI inspection by multiple operators may be impossible.*

See NPRM at 20728-20729.

In light of the above questions, API submits that the objectives to be achieved by the proposal do not lend themselves to prescriptive requirements. API agrees with PHMSA that prompt action must be taken following an extreme event; however, the need for inspection, the type of inspection, and the timing should be determined on a case-by-case basis by the operator who is in the best position to accurately determine the level of risk. PHMSA should understand that operators have the internal processes by which to make these determinations.

1. Modification of Existing Requirement

API members believe that the intent of PHMSA's proposed § 192.613(c) can be captured within §192.615(a), with a few modifications to existing requirements. API therefore suggests that PHMSA withdraw the proposal for a new §192.613(c) and instead make the following modifications to §192.615(a)(3):

§ 192.615 Emergency plans.

- (a)(3) Prompt and effective response, **including appropriate investigative or corrective action**, to a notice of each type of emergency, including the following:
 - (i) Gas detected inside or near a building.
 - (ii) Fire located near or directly involving a pipeline facility.
 - (iii) Explosion occurring near or directly involving a pipeline facility.
 - (iv) Natural disaster **or extreme weather event potentially threatening the safety of pipeline facilities.**

Should PHMSA not agree with API's suggested changes to §192.615(a), however, API requests that PHMSA consider the following concerns and revise the proposed new §192.613(c).

2. Conditions Triggering Extreme Weather Events Must be Explicit and Relative to Pipeline Risk

The weather events specifically identified by PHMSA (*i.e.*, hurricanes, floods, and earthquakes) are stated in broad terms. API requests that PHMSA provide a specific definition of the parameters of those weather events that will necessitate a pipeline inspection upon cessation. The current language suggests that pipeline inspections will be required if any of the specified weather events occur, and does not take into account the variability in severity that accompanies each of the above events. Additionally, the current language does not recognize the nuances in the particular physical design and construction of a pipeline in the area of the potential exposure. Such design and construction characteristics might, in and of themselves, mitigate the exposure or risk.

Further, given the variation that exists in the type and severity of weather events, API requests regulatory clarity on how PHMSA will define a "flood." For example, what amount of rainwater

accumulation, and in what circumstances, would constitute a flood? According to the National Flood Insurance Program, a flood occurs when “two or more acres of normally dry land, or two or more properties, are inundated by water or mudflow.”³¹ The “flood” event is not in itself a pipeline integrity risk, but could be so in conjunction with other characteristics, such as very high water flow velocity, volume, etc. Large rainfall that is easily handled in some areas of the country because of terrain or collection infrastructure can overwhelm other areas. API is ready to work with PHMSA on achieving the intended goal of the proposed regulation, but requests that PHMSA specify whether there are definite conditions that would trigger an inspection by a pipeline operator, or if the simple occurrence of a specified event itself would trigger an inspection.

API further requests recognition in the final rulemaking that many of these events, due to variables like intensity or duration of the event, geographic region affected, assets located in the affected areas, and design capacity of the pipeline assets to withstand the conditions of the extreme events, will potentially have widely disparate impacts on pipeline assets and operators.³²

3. “Other Similar Event” is Ambiguous

API is also concerned with the ambiguity of certain phrases in the proposed regulatory language, specifically the reference in proposed §192.613(c) to an “other similar event” in the list of extreme weather events that would require an inspection by pipeline operators. *NPRM at 20832*. That language could be interpreted to include any number of events, including tornadoes, wildfires, mudslides, blizzards, etc. Further guidance is necessary to alert operators to the circumstances that PHMSA expects would indicate potential damage to facilities. API suggests that PHMSA consider adopting a standard for other similar events, such as “other similar events **with a significant likelihood of damage to infrastructure.**”

4. Flexibility Needed for Completion of Inspections

API is concerned with the feasibility of conducting inspections within the 72-hour timeframe.³³ Inspecting to detect conditions that could adversely affect the safe operation of that pipeline will potentially require operators to perform various tests, the results of which may not be available within 72 hours. API members are ready to work with PHMSA to mitigate, to the extent practicable, threats to the public and the environment following an extreme weather event, but request that operators be allowed additional time if they determine that the proposed requirement cannot be met within 72 hours due to resource constraints or threats to the safety of pipeline personnel. API therefore recommends that the proposal be amended to allow operators to record

³¹ Flooding and Flooding Risks, Nat’l Flood Ins. Program (Nov. 2, 2015, 8:30 a.m.) https://www.floodsmart.gov/floodsmart/pages/flooding_flood_risks/ffr_overview.jsp.

³² *Shaken More than 580 Times, Okla. Is Top State for Quakes in 2014*, EnergyWire (Jan. 5, 2015) <http://www.eenews.net/stories/1060011066>. In 2014, Oklahoma experienced 585 earthquakes, a significant increase from the 100 experienced in the State in 2013. By contrast, California – a state twice the size of Oklahoma – experienced fewer than one-third of that number in 2014.

³³ The recent Mississippi flooding events highlights the difficulty of imposing an inspection requirement within 72 hours of “cessation.” The rain in this case was of an unprecedented volume within a very short period of time. The resulting floods and flow have grown and peaked over a week timeframe. The ability of operators to inspect pipelines crossing the river may potentially be limited for weeks, until water levels flow and subside.

the reasons for the delay in conducting required inspections beyond 72 hours and to maintain that information with inspection records.

There are several reasons why the proposed 72-hour window for conducting inspections is not feasible. First, underground pipe poses greater challenges for inspection than does above-ground pipe. Inspections may need to include more time- and resource-intensive direct assessments or ILI to assure pipeline integrity. Depending on the length of the pipeline and the size of the affected area, it therefore may not be possible to complete the required inspection in 72 hours due to resource constraints. Multiple operators may have assets located in the same geographic area that will need to be inspected after an extreme weather event. As a result, operators may be forced to compete for access to third-party resources necessary to complete an inspection, in which case the 72-hour timeframe would undermine the safety objectives contemplated by the agency in this rulemaking.

In addition, API requests that PHMSA consider building in flexibility to the proposed inspection requirements in recognition of operators' commitment to safety, not just of the public and the environment, but also of those employees who would be putting their personal safety at risk to inspect potentially affected pipeline facilities for the good of the communities in which they operate. API appreciates that PHMSA included language in the proposal to the effect that "cessation" of an extreme weather event occurs only when the affected area can be safely accessed by personnel and equipment. *NPRM at 20832*. API commends the Agency for recognizing that threats to personnel safety may not quickly dissipate following the conclusion of a severe weather event. Nevertheless, API requests that PHMSA allow operators flexibility in exceeding the 72-hour window when necessary to protect the safety of operator personnel.

B. Recordkeeping Requirements Must be Prospective

The NTSB issued a safety recommendation following a September 2010 gas transmission line failure in San Bruno, California asking the operator to confirm that it had "traceable, verifiable and complete" records. NTSB also issued a separate safety recommendation to PHMSA to inform the pipeline industry of the circumstances of the incident. *NTSB Safety Recommendations P-10-2, P-10-4, P-10-1 (Jan. 3, 2011)*.

In response to NTSB's recommendation, PHMSA issued an advisory bulletin in January 2011 that contained additional guidance on establishing MAOP and the records that pipeline operators should use to accomplish that objective. *Advisory Notice, 76 Fed. Reg. 1504 (Jan. 10, 2011)*. Of particular significance, the Agency advised pipeline operators to follow a new, three-part standard for verifying MAOP-related records. That standard, taken directly from one of NTSB's post-San Bruno safety recommendations, indicated that such records should be traceable, verifiable, and complete.

PHMSA issued a second advisory bulletin on establishing MAOP in May 2012. *Advisory Notice, 77 Fed. Reg. 26822 (May 7, 2012)*. Consistent with its previous guidance, the Agency reiterated that pipeline operators should adhere to NTSB's new (but undefined) "traceable, verifiable, and complete" standard for verifying MAOP related records. PHMSA also provided additional guidance on how pipeline operators should interpret each of those terms in

determining whether it had the information necessary to substantiate MAOP. Specifically, the Agency stated:

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.

PHMSA is aware that other types of records may be acceptable and that certain state programs may have additional requirements. Operator records should 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.

Id. (emphasis added).

Although referenced in NTSB's safety recommendations and discussed at some length in PHMSA's May 2012 advisory bulletin, the terms "traceable", "verifiable", and "complete" are not yet defined in Part 192, nor are they proposed to be defined in this NPRM. There is no express obligation to keep and maintain records solely for the purpose of establishing MAOP under current law. More than a dozen regulations in Part 192 explicitly require operators to create and maintain certain records, including records necessary to establish an alternative MAOP for a gas pipeline system.³⁴ However, there is no such express provision in the regulation governing establishment of MAOP at §192.619. In short, these terms should be defined if they continue to be used by the Agency in information requests, inspections and enforcement.

³⁴ See e.g., 49 C.F.R. §§ 192.14(b), 192.16(d), 192.112, 192.243(f), 192.328, 192.491, 192.517, 192.553, 192.620(c)(7), 192.709, 192.807, 192.947, 192.1011.

In response to the congressional mandate included in Section 23 of the 2011 PSA, operators of certain gas transmission lines had to conduct a records verification process to determine if they had sufficient information to substantiate the MAOP of their pipeline systems. Those operators also had an obligation to report the results of that review to PHMSA. The Section 23 MAOP verification and reporting process is what prompted the Agency to issue the May 2012 advisory bulletin. While that document contained additional guidance for verifying MAOP related records, the advisory bulletin did not change the regulations in Part 192 (Advisory Bulletins, and advisories and guidance documents generally, are not independently enforceable and do not replace notice and comment rulemaking). *American Bus Ass'n v. US*, 627 F. 2d 525, 529 (D.C. Cir. 1980) (an agency may not give legal effect to its informal pronouncements in a way that creates binding normal or imposes obligations beyond what the applicable statutes or regulations require). The existing and proposed Part 192 rules remain silent on the issue of whether an operator must maintain MAOP related records and, if so, the required standard for evaluating the sufficiency of those records.

As noted, neither PHMSA nor NTSB has defined the terms “reliable, traceable, verifiable or complete,” yet those terms continue to be used by the Agency in both inspections and enforcement actions. They are also used in this NPRM. In light of the significance that these terms have developed, this rulemaking should define them. Our suggestion on how the Agency should do that is set forth below.

1. Undefined “Reliable, Traceable, Verifiable and Complete” Standard

PHMSA uses the “reliable, traceable, verifiable and complete” standard in the NPRM, but does not define it. For example, the NPRM proposes a new general requirement in §192.13(e), which states that “[e]ach operator must make and retain records that demonstrate compliance with [Part 192]” and that such “records must be reliable, traceable, verifiable and complete.” *NPRM at 20828*. The NPRM proposes other recordkeeping requirements that would incorporate the same standard. *NPRM at 20830, 20839, 20846 (pipe and material properties used in remaining strength calculations); 20833 (records supporting MAOP); 20848 (Appendix A)*. However, PHMSA is not proposing to define the phrase “reliable, traceable, verifiable, and complete” in the NPRM. The Agency does not provide an explanation or justification for that omission in the NPRM or Preliminary RIA, and there is no other evidence in the record that sheds light on that decision. Given the importance and widespread use of this new standard throughout the NPRM, the phrase “reliable, traceable, verifiable, and complete” should be defined in the proposed rules, with some clarifications:

First, the term “reliable” should be stricken from this new undefined standard as unnecessary. While mentioned in passing in the initial advisories, NTSB did not use the term “reliable” in its safety recommendation to PG&E after the San Bruno incident, and PHMSA did not use it in its May 2012 Advisory. Moreover, the three other terms used in the proposed standard fully address the concept as articulated by both NTSB and PHMSA. To avoid uncertainty and confusion, the term “reliable” should be stricken from all of the regulations proposed in the NPRM before a final rule is issued.

Second, PHMSA should be aware that the terms “traceable, verifiable and complete,” whether retained only in guidance or defined in Part 192 as part of this rulemaking, will collectively be

viewed as “records” in any judicial review of Agency action, pursuant to the Federal Rules of Evidence (FRE). *FRE Rules 1001, 1003 and 1004*. This definition allows for the use of both duplicates and affidavits. More specifically, if original records have been lost or destroyed, and there is no suggestion of bad faith, then duplicates may be accepted, consistent with FRE 1003. Similarly, affidavits by a person with personal knowledge may be used to provide documentation of certain actions taken, but not used in lieu of data or records required to be generated and maintained. This is established law, and PHMSA should recognize it in using or defining these terms.

With the above as background, we recommend that PHMSA provide definitions of these terms in the final rule, using the concepts laid out in Agency’s May 2012 advisory bulletin. The excerpts from the advisory bulletin set forth in the pages above should form the basis for a regulatory definition. Operators have already become familiar with that approach as a result of the effort to comply with the MAOP verification process required under Section 23 of the 2011 PSA and the 2012 guidance. The interests of efficiency and consistency would be well served by carrying those general concepts forward to a formal definition.

The following are proposed definitions for these terms, based on the Agency’s 2012 guidance in the advisory bulletin. The description of verifiable in the May 2012 advisory bulletin should be included in the final rule, with one change to incorporate a subsequent clarification in a PHMSA July 31, 2012 interpretation that “a single quality record” could meet the advisory bulletin’s verifiable standard.³⁵ The description of a complete record in the May 2012 advisory bulletin is generally acceptable.

Finally, an additional provision should be added to all places in the final rule where the “Traceable, Verifiable and Complete records” standard is noted. That provision should acknowledge that this standard can obviously only be applied prospectively in those instances where original records have not been retained. The development of comprehensive, generally accepted standards and practices for gas pipeline safety did not emerge until the latter half of the 20th century. The American Society of Mechanical Engineers did not release the first industry standard for the safety of gas transmission lines until 1952, and PHMSA’s predecessor did not adopt the original federal gas pipeline safety regulations until 1970. These early pipeline safety codes and regulations did not contain extensive recordkeeping requirements, and the records that pipeline operators otherwise maintained often varied to a significant extent from company to company. Pipeline operators began to maintain additional, and far more detailed, records as the federal pipeline safety program matured and technological advancements improved the ability to create, exchange, and maintain information. In other words, recordkeeping standards and practices have evolved considerably over time, and that trend is expected to continue in the future.

Accordingly, the Part 192 definition should provide that:

³⁵ *PHMSA Interpretation for American Gas Association (Jul. 31, 2012)*.

§ 192.3 Definitions.

Traceable, Verifiable and Complete

Traceable records mean 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. Where original documents are not available, other records may be acceptable if consistent with the requirements of the Federal Rules of Evidence.

Verifiable records mean those in which information is confirmed in a single quality record, or confirmed where necessary 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. The only acceptable use of an affidavit would be as a complementary document that is consistent with the requirements of the Federal Rules of Evidence.

Complete records mean 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.

Other types of records beyond the examples provided may be acceptable. Due consideration must be given to contemporaneous standards and practices in determining whether a record is traceable, verifiable, or complete. 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.

2. Additional Express Recordkeeping Requirements.

The Agency also proposes to include additional express recordkeeping requirements in numerous other sections of the NPRM.³⁶ For pipe material and design, operators must retain original manufacturing records which document tests and inspections in effect at the time of manufacture, including yield strength, ultimate tensile strength and chemical composition. *Id.* The NPRM would also add general duty recordkeeping requirement at §192.13(e)(2) and an entirely new “Appendix A” to Part 192, titled “Records Retention Schedule for Transmission Pipelines,” which operators would be required to follow under §192.13(e)(1). *NPRM at 20828; 20848-20852.* The proposed Appendix A would add 85 rule-specific references to the retention time for records generated under each regulatory requirement listed.

A general duty recordkeeping requirement, such as that proposed at §192.13(e)(2), could be interpreted to require the maintenance of records even where there is no express requirement or timeline prescribed in the regulations. While a summary appendix of recordkeeping requirement

³⁶ See e.g., *NPRM at 20827 (Class location); 20828 (pipe material, pipe design); 20829 (pipeline components, welders qualification records, plastic pipe qualifications).*

could be useful for both the pipeline industry and the Agency, many of the record retention requirements listed in Appendix A as proposed in the NPRM are completely new, and the majority would add as a new requirement that operators keep covered records for the life of the facility. Fully two thirds of the 85 proposed listings in Appendix A are new to Part 192, many without any direct link to the rules NPRM text.

The Preliminary RIA does not consider the full regulatory impacts and burdens of these new recordkeeping obligations. Rather, the Preliminary RIA appears to assume that the NPRM simply contains clarifications of existing obligations. That is not the case. Many of the recordkeeping requirements proposed in the NPRM create additional or more stringent obligations and must be analyzed accordingly in the Preliminary RIA, including from a cost-benefit and burden hours perspective.

PHMSA should clarify in the final rule that its new recordkeeping requirements do not apply retroactively, particularly those relating to design, construction, initial inspection, and initial testing. If no original records for a given line or segment exist, it is impossible to meet the new requirements as proposed. An operator may need to rely on alternative documentation or create new records, but as proposed the rule is illogical. The PSA itself prohibits the Agency from retroactively applying new requirements to pipelines in existence when a new standard is adopted, and that prohibition should apply to recordkeeping requirements as well as substantive provisions.³⁷ To avoid violating the non-retroactivity provision, the regulations proposed in the NPRM (including §192.13(e) in particular) should be modified to clearly state the new recordkeeping requirements only apply prospectively as of the effective date of the final rule.

Similarly, the references to “acquire” in the proposed regulations also suggest that pipeline operators would have an affirmative obligation to obtain old or otherwise unavailable records to meet that obligation. Assuming that PHMSA has the authority to issue such a regulation, the burdens imposed on pipeline operators far outweighs the benefits of any information that might be obtained from such an effort. That is particularly true for legacy pipeline systems constructed prior to the issuance of the original federal rules or the emergence of generally-accepted industry standards and practices for documentation and recordkeeping. The existing regulations in Part 192 use phrases like “keep,” “maintain,” or “retain” in describing the extent of a pipeline operator’s recordkeeping obligations.³⁸ That language appropriately connotes that a contemporaneous record must be kept, maintained, or retained after an activity is complete, not that an operator must acquire records concerning activities conducted years earlier.

Accordingly, API proposes the following changes to §192.67 and §192.205 as proposed:

³⁷ 49 U.S.C. § 60104(b); 35 Fed. Reg. 13248, 13250 (Aug. 19, 1970); see *In the Matter of Belle Fourche Pipeline Company, Decision on Reconsideration*, CPF No. 5-2004-5010 (2009 WL 7810536) (Jul. 15, 2009); *Letter from R.. Beam, Associate Director for OPS, Materials Transportation Bureau, to A. Colabella*, (Nov. 7, 1984); *Letter from R.. Beam, Associate Director OPS, Materials Transportation Bureau, to A. Colabella, Jr.* (Nov. 19, 1984); *Operating Pressure for Platform Piping; Interpretation, Department of Transportation, Materials Transportation Bureau, Docket No. OPSO-35* (Oct. 15, 1976).

³⁸ See e.g., 49 C.F.R. §§ 192.14(b), 192.112, 192.243(f), 192.328, 192.491, 192.517, 192.553, 192.620(c)(7), 192.709, 192.807, 192.947, 192.1011.

§ 192.67 Records: Materials.

For transmission pipe manufactured [or, in the alternative “ordered”] after (Insert date 6 months following the date of this Final Rule). 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.

§ 192.205 Records: Pipeline components.

For valves manufactured after (insert date 6 months following the date of this Final Rule). Each operator of transmission pipelines must ~~have acquire and retain~~ records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. **All rated components, such as** flanges, fittings, branch connections, extruded outlets, anchor forgings, ~~or and~~ other components with material yield strength grades of 42,000 psi or greater **manufactured after (insert date 6 months following the date of this Final Rule), each operator of transmission pipelines** must ~~acquire and retain~~ 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.

While the NPRM does not propose to change the text of §192.603(b), Appendix A describes that regulation as imposing a lifetime recordkeeping requirement to administer the operations, maintenance, and emergency procedures established under §192.605, including Class location determinations under §192.5, §192.609, and §192.611. The notion that §192.603(b) creates a lifetime recordkeeping requirement lacks any support in the text, structure, or history of Part 192. Several provisions in Part 192 explicitly require operators to retain records for the life of a pipeline, such as the conversion of service rules in §192.14(b), the welding requirements in §192.243(f), the corrosion control requirements in §192.491, the testing requirement in § 192.517, and the alternative MAOP rules in §192.620. However, there is no record retention period specified in §192.603(b), let alone an obligation that extends for the life of a pipeline. PHMSA’s attempt to surreptitiously impose such a requirement in the descriptive language in Appendix A is at best disingenuous.

Moreover, the fact that other Part 192 regulations prescribe a lifetime record retention period completely undermines the argument that such an obligation can be read into §192.603(b). PHMSA clearly knows how, and when, to include a lifetime recordkeeping in a regulation. Indeed, nearly all of the new recordkeeping provisions proposed in the NPRM contain express language to that effect. The omission of a similar requirement from § 192.603(b) demonstrates that there is no such obligation. Similarly, interpreting §192.603(b) as creating a lifetime recordkeeping requirement produces unnecessary conflicts with other provisions in Part 192. For example, the 5-year record retention provision for certain maintenance activities conducted by transmission line operators in §192.709 serves no purpose if a lifetime recordkeeping requirement is imposed by §192.603(b). Indeed, there is no need for any of the other regulations in Subpart L or Subpart M to specify a record retention period under that interpretation. All of the activities that operators must perform to comply with those subparts are covered by the procedural manual requirements in §192.605 and, presumably, the lifetime recordkeeping provision in §192.603(b). The fact that other record retention periods are specified in Subparts L and M demonstrates the lack of merit in PHMSA’s position.

Finally, the regulatory history does not suggest that PHMSA or its predecessors intended to adopt a lifetime recordkeeping requirement in §192.603(b). Adopted as part of the original federal gas pipeline safety regulations in 1970, that regulation is derived from a comparable historical requirement in Section 850.2(c) the USA Standard Code for Pressure Piping, Gas Transmission and Distribution Systems, USAS B31.8-1968 (“B31.8”). *35 Fed. Reg. 13248 (Aug. 19, 1970)*. Like the original federal rules, B31.8 required operators to keep certain records for the life of a pipeline. However, Section 850.2(c) of B31.8 did not include a specific record retention period, and there is no evidence to suggest that PHMSA’s predecessor altered that understanding in adopting that requirement into §192.603(b). 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. That opinion did not emerge until very recently, i.e., after NTSB issued its safety recommendations to PG&E and Congress enacted the MAOP verification mandate in Section 23 of the 2011 PSA. The Agency’s longstanding failure to support the view expressed in Appendix A provides further evidence that §192.603(b) does not create a lifetime recordkeeping requirement.

3. Inconsistencies Between Appendix A and Part 192 Requirements

Appendix A is proposed to be appended to Part 192 in order to summarize particular retention periods for transmission pipeline records. The purpose of Appendix A and the basis for the retention periods specified are unclear, however. The heading of the table in Appendix A contains a note that it is a “summary provided for convenience only” and that the “referenced code section specifies” the actual retention requirements. *NPRM at 20848 (emphasis added)*. Yet the table contains numerous retention periods that are proposed as enforceable requirements under §192.13(e)(1), but which are not, in fact, not specified in any existing or other proposed section of Part 192. *NPRM at 20828 (proposed amendment to §192.13(e)(2) requiring operators of transmission pipelines to “keep records for the retention period specified in appendix A to Part 192”)*. API requests that PHMSA remove those periods specified in the table contained in Appendix A that have no basis in either existing or proposed new text of Part 192. This includes over half of the records requirements under proposed Appendix A as well as numerous design, construction, corrosion control, and operations records.³⁹

C. PHMSA Should Incorporate Updated Industry Standards

As noted throughout these comments, PHMSA proposes to incorporate editions of industry standards that are already outdated (e.g., Section II.E. and Section III.C.5). Throughout Part 192, API favors the use of the most up to date, technically sound, and well-reviewed consensus standards where applicable as part of the safety standards for pipelines, as required under the PSA. *49 U.S.C. § 60102(l) (requiring industry standards incorporated into the federal pipeline safety regulations to be updated, to the extent appropriate and practicable)*. Generally, the ANSI standard review and adoption process assures the technical soundness and involves participation by a cross-section of interested stakeholders. In order to remain accredited these standards must be periodically reviewed and either updated or reaffirmed, which typically occurs

³⁹ *49 C.F.R. §§ 192.144, 192.150, 192.153, 192.205, 192.225(b), 192.283, 192.303, 192.305, 192.307, 192.383, 192.9452(a), 192.459, 192.461, 192.465 (a-e), 192.467(d), 192.473, 192.475, 192.476(d), 192.477, 192.478, 192.481, 192.485(c), 192.603(b), 192.605, 192.607(c), 192.609, 192.612, 192.713(a-c)*.

once every 5 years. This process provides transparency in the development and modification of standards, opportunities for participation, resolution of comments, approval by Committee vote, and incorporation of up to date industry data, technology and capabilities.

PHMSA’s process for adopting updated editions of the standards incorporated by reference (IBR), however, is neither prompt nor transparent. While API understands that PHMSA may not always automatically adopt the latest edition of each IBR standard, the process by which the Agency incorporates updated standards is inordinately slow. Despite claims by the Agency that it “constantly reviews new editions and revisions to relevant standards and publishes a proposed rule every 2 years to incorporate by reference new or updated consensus standards,” standards incorporated under Part 192 are often outdated by several editions and some are 10 or more years out of date. *Compare PHMSA Final Rule, 80 Fed. Reg. 168, 176 (Jan. 5, 2015)(quoted above) with Part 192.7 (incorporating by reference ASME B31.8S-2004, API RP 1162-2003, ASME B31G-1991 (reaffirmed in 2004)).*⁴⁰

This creates problems for operators who use updated standards but have to reconcile two editions of the same standard to comply with Part 192. For example, an operator has to follow the most recent edition so that the manufacturer certifies that the standard was met and the IBR edition so the operator can certify that the IBR edition was met. In other instances, PHMSA appears to prefer outdated standards over more recent editions despite having representation (or at least the opportunity for representation) on many of the standard-developing committees. This does not appear to be in the spirit of the statutory mandates of the NTTA and does not foster open communications between PHMSA and the regulated community. The NTTA codified OMB guidance, which recommended that agencies undertake review of incorporated standards every three to five years. *Revised OMB Circular A-119 (Jan. 27, 2016)*. Examples of outdated PHMSA standards are noted in the table below.

Standard	Part 192.7 IBR Edition	Subsequent or Current Editions
API Std 1104	20 th , 2005, errata 2007 and 2008	21 st , 2013
API RP 1162	1 st , 2003	2 nd , 2010
API Spec 6D	23 rd , 2008, errata through 2012	24 th , 2014
ASME B31G	1991, reaffirmed 2004	2009, 2012
ASME B31.8S	2004	2010, 2012, 2014

API recommends that PHMSA communicate with both the standards organization and the PHMSA Technical Advisory Committees when it decides not to incorporate by reference within one year of publication, stating the reasons for non-adoption so that the standards organizations

⁴⁰ In the final rulemaking in 2015, PHMSA also noted that it “regularly reviews updates to currently referenced consensus standards as well as new editions of standards to ensure that their content remains consistent with the intent of the pipeline safety regulations” but referenced—in contrast to its self-described routine 2 year review—updates published in 2015, then 2010, then 2007, 2006, 2004, 1998 and 1996. *Final Rule, 80 Fed. Reg. 168, 169 (Jan. 5, 2015)*.

have an opportunity to address PHMSA concerns and the Advisory Committee can advise PHMSA on the matter.

D. Management of Change Requires Phase-In Period

The NPRM proposes to include a new requirement under § 192.13(d) to require each operator of an onshore gas transmission pipeline to develop and follow a management of change (MOC) process. *NPRM at 20828*. This MOC process must comply with ASME/ANSI B31.8S, section 11, and address “technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary.” *Id.* While this requirement already exists for pipelines located in HCAs, it would be a major change for those operators who do not already implement formal MOC procedures outside of their IM programs. Further, this proposal is not consistent with a risk based management approach and will divert resources to the lower risk program elements. Therefore, API requests that any proposal include a reasonable phase-in period of time for operators to prepare and implement detailed and thorough procedures throughout their systems. It will require at least 2 years from any final rule for operators to design a MOC system, vet vendors, train employees, and begin implementing a system wide MOC process.

In addition, the NPRM proposes to require under §192.13(d) that the MOC process include among other things “qualification of staff.” API requests that PHMSA revise this reference to clarify that “qualification of staff” means that the staff is qualified on the MOC process as follows.

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

- (d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, risks to the public and environment as an integral part of managing pipeline design, construction, operation, maintenance, and integrity, including management of change. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11, that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations and requirement that staff be qualified on the process ~~qualification of staff~~.

E. Certain Proposed Definitions Require Clarification

The NPRM proposes a number of revisions and additions to definitions in §192.3 that are ambiguous, unclear and warrant additional clarification so that they are consistently applied under Part 192. API proposes the following revisions:

1. Dry gas

PHMSA proposes a new definition for dry gas, use the terms “excessive” and “electrolytes” without defining them. API therefore suggests the following changes:

§ 192.3 Definitions.

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~~ not subject to upsets above this concentration lasting more than 24 continuous hours.

2. *Electrical survey*

PHMSA's proposed definition for electrical survey appears to be too narrow in scope and may inadvertently exclude DCVG and ACVG surveys. For that reason, API suggests the following revisions:

§ 192.3 Definitions.

Electrical survey means a series of closely spaced measurements of the potential differences between to reference electrodes to determine where the current is leaving the ~~pipe on ineffectively coated or bare~~ pipelines.

3. *Hard Spot*

API notes a minor typo in the definition of "hard spot" as follows:

§ 192.3 Definitions.

Hard spot means an area on a steel pipe having a minimum dimension greater than two inches (50.8 mm) in any direction and a hardness greater than or equal to Rockwell 35 HRC (~~Brinnell~~ Brinell 327 HB or Vickers 345 HV10).

4. *In-line Inspection*

PHMSA's proposed definition of in-line inspection (ILI) would benefit from the following revision:

§ 192.3 Definitions.

In-line inspection (ILI) means ~~that the inspection of a pipeline from the interior of the pipe using an in-line inspection tool, which is also called intelligent or smart pigging~~ the act of assessing the condition of the pipe walls through the use of an internal inspection device, frequently called intelligent or smart pigging, traveling down the pipeline while gathering data on the pipe's condition.

5. *Legacy Construction Technique*

The Agency's proposed definition of "legacy construction technique," inappropriately includes the repair technique of puddle welds. As such, API requests that PHMSA strike the reference to puddle welds from the proposed definition as it is not a construction practice.

6. *Legacy Pipe*

PHMSA's proposed definition of "legacy pipe" includes wrought iron and pipe made from Bessemer steel which are manufacturing materials as opposed to techniques. For that reason, API recommends that PHMSA clarify the definition as follows:

§ 192.3 Definitions.

Legacy pipe means steel pipe manufactured using any of the following techniques **or materials**, regardless of the date of manufacture:

[...]

7. Significant Seam Cracking

PHMSA defines the term “significant seam cracking,” yet does not reference the term in the remainder of Part 192. For that reason, API requests that PHMSA strike this definition from the proposed rule.

8. Significant Stress Corrosion Cracking

The Agency proposes a definition of “significant stress corrosion cracking” that is complicated and potentially subject to varying interpretations (i.e., “means a stress corrosion cracking (SCC) cluster in which the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS”). API recommends that PHMSA instead rely on established industry definitions of “likely crack,” “possible crack” and “unlikely crack” found in the forthcoming API Recommended Practice 1176, Assessment and Management of Cracking in Pipelines and as discussed and proposed in revisions in Section III.B. on repair criteria. These terms are based on operator field experience and collaboration with ILI vendors.

9. Transmission Line

Without explanation, PHMSA proposes to revise the definition of “transmission line.” For purposes of clarity, API recommends that PHMSA reinstate a portion of the language it proposed to delete as set forth below:

§ 192.3 Definitions.

Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) **has operates at a hoop stress of MAOP of** 20 percent or more of SMYS; or (3) transports gas within a storage field.

10. Pipelines that Can Accommodate ILI

API proposes that PHMSA define the “pipelines that can accommodate inspection by means of instrumented inspection tool” under Part 192. The following definition provides for operational impediments, such as flow rate, for pipelines that may technically be able to accommodate ILI but where product flow rates will not move an ILI tool through the pipeline.

§ 192.3 Definitions.

Pipelines that can accommodate inspection by means of instrumented inspection tool means a length of pipeline that has sufficient product flow to propel the ILI tool at speeds necessary to accomplish the inspection and through which a free-swimming commercially available ILI tool can travel and inspect the entire circumference of the pipe.

F. MAOP Exceedance Reporting Should Only Apply to Transmission Lines

Congress amended the PSA in 2011 to require gas transmission line operators to report MAOP exceedances to PHMSA and state partners on or before the 5th day following the date of exceedance. 49 U.S.C. § 60139(b)(2). PHMSA proposes to codify this statutory obligation by revising the safety-related-condition reporting requirements at 49 C.F.R. §191.23(a)(9) (to require reporting), §191.23(b)(4) (to preclude operators from relying on the exception from safety-related condition reporting if a pipeline is repaired or replaced before the reporting deadline), and §191.25 (to require the filing of safety-related condition reports for MAOP exceedance within 5 calendar days). Because this proposal is consistent with the statutory mandate, API supports the proposed changes in the NPRM for transmission pipelines. That said, API has strong objections to any subsequent expansion of this reporting requiring to unregulated gathering pipelines.

G. Reassessment Intervals Requires Clarification

Consistent with 2011 amendments to the PSA to provide for a technical correction, the NPRM proposes to revise 49 C.F.R. § 192.939(a) to allow operators to request a six month extension of the seven calendar year reassessment interval for an operator's covered pipeline segments, if the operator submits written notice in accordance with §192.949 with sufficient justification for the extension. API appreciates PHMSA's proposal and requests that PHMSA clarify that the six month extension begins after the close of the seven calendar year reassessment interval period, consistent with the 2011 revision to 49 U.S.C. § 60109(c)(3)(B).

H. Low Stress Reassessment Revisions are Reasonable

PHMSA proposes a clarifying revision to replace "electrical survey" with "indirect assessment" in Part 192.941, which addresses external corrosion on both cathodically protected pipe and unprotected pipes. API appreciates this clarification and does not have concerns with the proposed language.

V. Conclusion

API appreciates the opportunity to comment on this proposed PHMSA rulemaking. The proposals are numerous and expansive and the sheer volume of new or revised rules proposed is unprecedented (existing regulations for gas pipelines, at 49 C.F.R. Part 192, would double if this proposal is implemented as proposed). Moving to a final rule on an unprecedented number of rule changes, despite an unprecedented number of public comments – would likely lead to prolonged litigation. As reflected in the preceding comments, API and its members have significant comments on the proposals regarding: (1) gas gathering, (2) assessment and repair criteria outside HCAs; (3) new material documentation and testing requirements; (4) new MAOP verification and testing requirements (including the need for new definitions); (5) revisions to corrosion control regulations; (6) revisions and additions to existing integrity management regulations; and (7) revisions to recordkeeping requirements (including the need for new definitions).

Prior to preparing a final rule, API recommends that PHMSA review and consider public comments, hold public meetings to discuss issues of concern, and provide further opportunity for submission of public comments. API and its members look forward to working cooperatively with PHMSA to address the issues raised in these comments.

VI. Appendix

A. Social Cost of Greenhouse Gas Emissions

In order to determine the full benefits of the proposed rule, PHMSA uses both the Social Cost of Carbon (SCC) and the Social Cost of Methane (SC-CH₄), as developed by EPA, to monetize any carbon dioxide or methane emissions avoided or reduced by the proposed rule. Though both social cost estimates have been used to calculate benefits of various rules across agencies, their continued application is flawed in general and specifically by PHMSA.

1. Overview of Issues Associate with the Social Cost of Methane

The Preliminary RIA uses a paper by Marten et al. (2014),⁴¹ to monetize the greenhouse gas (GHG) emission reduction benefits associated with reduced methane emissions. Marten et al.'s estimate of the social cost of methane is based on modeling results from three Integrated Assessment Models (IAMs). These IAMs are also the basis for the social cost of carbon estimates, which PHMSA also uses. The methodology used by Marten et al. is consistent with the Interagency Working Group's approach to estimating the SCC, as stated by PHMSA,⁴² in that it uses the same three IAMs, five socioeconomic and emission scenarios, discount rates and approach for averaging social costs across scenarios and IAMs. As noted in comments to other agencies that have used the SC-CH₄,⁴³ the SC-CH₄ is highly uncertain and the causes of this uncertainty are not well understood, is likely overstated, has not undergone a full scientific peer-review, and due to its construction, inherits all of the issues and challenges associated with estimating the SCC.

2. The Preliminary RIA's estimates of benefits from methane reductions using SC-CH₄ estimates are highly uncertain and likely overstated

As noted by NERA,⁴⁴ Marten et al. have developed a novel means of estimating the SC-CH₄ which the EPA believes is an improvement over the previous estimates which rely on calculations regarding the global warming potential (GWP) of methane. Previous available literature multiplied the GWP for non-CO₂ gas by the SCC in order to determine the social cost of that gas. While this method still relies on the SCC, which is an imperfect estimate in its own right, the benefit of this method was the abundance of literature and therefore estimates for the SC-CH₄. The analysis in the Preliminary RIA relies on just one study, Marten et al. (2014), which provides estimates for the SC-CH₄ that are not only inconsistent with but also significantly greater than the available estimates that have been developed using the GWP methodology.

A second factor which would cause the SC-CH₄ to be overstated is that, as applied by PHMSA, the SC-CH₄ represents the global benefits rather than the domestic benefits of the methane

⁴¹ Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold, and A. Wolverton. 2014. Incremental CH₄ and N₂O Mitigation Benefits Consistent with the US Government's SC-CO₂ Estimates. Climate Policy.

⁴² PHMSA, PRIA, Appendix B, page 158.

⁴³ API comments to EPA, BLM.

⁴⁴ NERA Economic Consulting, 2015. Technical Comments on the Social Cost of Methane As Used in the Regulatory Impact Analysis for the Proposed Emissions Standards for New and Modified Sources in the Oil and Gas Sector. Prepared for the American Council for Capital Formation.

emission reductions estimated in the Preliminary RIA. While the domestic benefits are provided as an output from the modeling that has generated the SC-CH₄, Marten et al. reported only the global benefits, which have in turn rendered their estimate of the SC-CH₄ unfit for benefit–cost analysis. Including only the global benefits overstates the emission reduction benefits of the proposed rule and is contrary to the Office of Management and Budget’s *Circular A-4* (OMB, 2003) which states specifically “Your analysis should focus on benefits and costs that accrue to citizens and residents of the United States. Where you choose to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately.”⁴⁵ Though Agencies may argue that the climate change is a global phenomenon and therefore a global value is warranted, two facts remain. First, OMB guidelines require inclusion of both the global and domestic values if global benefits are to be included. Second, though climate change is a global phenomenon, the damaging impacts can, and should, be measured on a domestic scale for any rule that attempts to compare the benefits of reduced greenhouse gas emissions with domestic costs.

Third, as noted by NERA,⁴⁶ portions of Marten et al. lack support from the scientific literature. In particular, the assumptions used regarding indirect effects on radiative forcing from changes in tropospheric ozone and stratospheric water vapors are uncertain, not validated, and could be a substantial source of overstatement in the SC-CH₄ estimates. According to NERA, including these indirect effects could increase the SC-CH₄ estimate by 36% when using a 3% discount rate relative to a scenario in which the indirect effects are assumed to be zero.

Finally, the SC-CH₄ estimates are based on an average of five socioeconomic scenarios, four of which assume no additional incremental policies to reduce emissions in the future (“business-as-usual” scenarios). Because of the assumption that no other policies will be put in place to reduce emissions, the SC-CH₄ estimated in this manner will overstate the possible benefit of any one policy to which it is applied. This ignores reality, as evidenced by the multiple proposed regulations currently outstanding, all of which apply the SC-CH₄ to monetize the estimated benefits of emission reductions. Were other potential policies included in the estimation, the future emissions assumed would be lower, thereby lowering the damage that is being assigned to emissions in this Preliminary RIA. Lower damages as a result would in a lower estimate for the SC-CH₄.

3. *The social cost of methane lacks a full scientific peer review.*

The Preliminary RIA not only relies on estimates for the SC-CH₄ that are supported by only one study, but that study was not be subject to a full scientific peer review. This calls into question the reliability of the estimated benefits of the proposed regulation. More thorough peer review of the methodology is warranted for three reasons:

First, IAMs have been modified beyond how they were used in SCC, and not reviewed by the original model developers. The SC-CH₄ estimates are based on an approach that has simplified the models in addition to modifying them, disregarding the original developers’ scientific

⁴⁵ Office of Management and Budget, *Circular A-4*, September 17, 2003. p 15.
https://www.whitehouse.gov/omb/circulars_a004_a-4/

⁴⁶ NERA Economic Consulting, 2015.

efforts. These are no longer the same models that were originally developed for estimating the SCC. Additionally, other researchers in this field have not had a chance to review and validate the methodological changes, or provide additional input that could improve or correct the SC-CH₄. This is especially important given the inconsistency between the SC-CH₄ as developed by Marten et al. and the significant gap between other estimates in the published literature and the Marten et al. estimate, which is significantly larger.

Second, in developing the SC-CH₄ modeling, Marten et al. modified two of the three IAMs used, as noted above. Specifically, Marten et al. sought to standardize assumptions and calculations between the three models in the interest of harmonization. As an example, Marten et al. altered the PAGE model by replacing its existing CH₄ mechanisms with a simpler set of exogenously-specified changes in radiative forcing⁴⁷ – making it more like the DICE model, but less useful overall. By potentially “over-harmonizing” the models, the results could be more similar than they should be, reducing the variation and overshadowing insights that could be gleaned about modeling uncertainty by making valid comparisons between the models.

Finally, while the Marten et al. work has been published in a reviewed journal and been subject to an internal EPA peer-review, the full methodology has not been made available to the general scientific community for a rigorous peer-review, or review specific for policy work. In fact, EPA’s internal peer-review (a board of three reviewers) did not find consensus that the estimate is valid and appropriate for policy use. In fact, one of the reviewers acknowledge that agencies should be cautious and forthcoming of the shortcomings of this methodology when using it in policy applications, and no reviewer specifically endorses this methodology as appropriate for use in benefit-cost analysis of regulatory actions.

4. 1.2 Overview of Issues Associated with the Social Cost of Carbon

As noted above, the SC-CH₄ is built upon the methodology used to develop the SCC by the Interagency Working Group. As a result, the SC-CH₄ inherits all of the unresolved issues associated with the SCC.

EPRI (2014)⁴⁸ provides an in-depth technical assessment of the SCC estimates. They find significant inconsistencies across the three IAMs in the predicted temperature change and sea level rise change from the same increase in emissions and same underlying socioeconomic conditions. The temperature responses result from differences in the modeling of the carbon cycle, non-CO₂ radiative forcing, and climate sensitivity. Even in the short-term, through 2040, the IAMs can yield temperature changes that vary across models by a factor of two for the same emissions scenario.

The economic damage functions linked to these temperature changes and sea level rise estimates are also very different. For example, one IAM shows gains in GDP through 2100 for some scenarios with increased emissions, while the other two IAMs show losses for the same scenarios and emissions. The damage functions themselves are arbitrary and not based on significant

⁴⁷ NERA Economic Consulting, 2015.

⁴⁸ S.K. Rose, D. Turner, G. Blanford, J. Bistline, F. de la Chesnaye, and T. Wilson. Understanding the Social Cost of Carbon: A Technical Assessment. EPRI, Palo Alto, CA: 2014. Report #3002004657.

empirical data or economic theory (NERA 2014).⁴⁹ For example, one can easily plot two damage functions that are both consistent with the few current data that are available, but which produce widely different damages in the distant future.

EPRI concludes that the significant differences in the structure of the models, which lead to significant differences in the damages estimates, are not well understood or explained. As a result, EPRI concludes that it is difficult to assess whether the differences reflect true scientific uncertainty (and therefore they should be retained) or the differences are topics that should be resolved and standardized.

The EPRI results also call into question the approach of averaging the SCC models across different socioeconomic scenarios to form a single estimate of the SCC for a particular discount rate. EPRI concludes that the inconsistencies in the models, the lack of robustness of the models, and the fact that they may not be truly independent may make such averaging inappropriate. Such averaging may also be inappropriate because it assumes that each estimate is equally reliable and obscures the true uncertainty about the SCC that exists in the scientific literature. Gillingham et al. (2015)⁵⁰ conclude that the concept of relying on an ensemble of models to capture total uncertainty is not theoretically sound and furthermore, based on their empirical data, is a “deficient” approach, because it fails to capture the full range of uncertainty that affects the models.

Other reviewers have been even less enthusiastic. Pindyck’s (2013) review of the IAMs led him to conclude:

*“These models have crucial flaws that make them close to useless as tools for policy analysis: certain inputs (e.g., the discount rate) are arbitrary, but have huge effects on the SCC estimates the models produce; the models’ descriptions of the impact of climate change are completely ad hoc, with no theoretical or empirical foundation; and the models can tell us nothing about the most important driver of the SCC, the possibility of a catastrophic climate outcome. IAM-based analyses of climate policy create a perception of knowledge and precision, but that perception is illusory and misleading.”*⁵¹

⁴⁹ NERA. 2014. A Review of the Damage Functions Used in Estimating the Social Cost of Carbon. Comments prepared for the American Petroleum Institute.

⁵⁰ Gillingham et al. 2015. Modeling Uncertainty in Climate Change: A Multi-model Comparison. Cowles Foundation Working Paper. No. 2022.

⁵¹ Pindyck, Robert. 2013. “Climate Change Policy: What Do the Models Tell US”. Journal of Economic Literature 2013, 51(3): 860-872.