BEFORE THE
U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Pipeline Safety:	**)**	
Safety of Gas Transmission Pipelines:	**)**	
Repair Criteria, Integrity Management	**)**	
Improvements, Cathodic Protection,	**)**	**Docket No. PHMSA-2011-0023**
Management of Change, and Other	**)**	
Related Amendments	**)**	

Petition for Reconsideration
of the Interstate Natural Gas Association of America
and the American Petroleum Institute

Filed September 23, 2022

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I. Introduction

Pursuant to 49 C.F.R. § 190.335(a), the Interstate Natural Gas Association of America (INGAA) and the American Petroleum Institute (API) (the Associations) submit a Petition for Reconsideration (Petition) of the final rule issued by the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued in Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, (the Final Rule) published in the Federal Register on August 24, 2022.[1]

INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 26 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA's members operate nearly 200,000 miles of pipelines and serve as an indispensable link between natural gas producers and consumers.

API is the national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and 8 percent of the U.S. economy. API's more than 600 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.

The Final Rule is the last in a trilogy of final rules[2] that adopted the most significant amendments to PHMSA's Part 192 pipeline safety standards since they were first adopted in 1970. It strengthens integrity management requirements for data integration, risk assessments, and preventive and mitigative measures; adopts new repair criteria for pipelines not located in high consequence areas (HCA); revises the calculation of critical strain levels in pipe with dent anomalies or defects; revises corrosion control regulations affecting external corrosion, internal corrosion and stress corrosion cracking; modifies analysis for calculating predicted failure pressure; and extends Management of Change requirements to non-HCA pipeline segments. In addition, the Final Rule incorporates by reference into Part 192 two additional industry standards and extends provisions of previously incorporated standards into additional regulations.

Pipeline safety is the top priority of the Associations and their members. The Associations strongly support the Final Rule because the strengthened and enhanced requirements will enhance pipeline safety and help advance our industry's efforts to achieve a perfect safety and reliability record for our nation's natural gas pipelines. The Associations have publicly championed PHMSA's efforts to finalize this important rulemaking based on the consensus built through the Gas Pipeline Advisory Committee (GPAC) process

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[1] 87 Fed. Reg. 52,224 (Aug. 24, 2022).

[2] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, Final Rule, 84 Fed. Reg. 52,180 (Oct. 1, 2019) (2019 Gas Transmission Rule); Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, Final Rule, 86 Fed. Reg. 63,266 (Nov. 15, 2021).

II. Executive Summary

The Associations support the Final Rule, but files this Petition requesting that PHMSA reconsider several provisions. First, the Associations request additional time to implement the provisions of a complex rule that, while took over ten years to develop, contains several unanticipated provisions that deviated from those that were proposed or from GPAC recommendations. A nine-month effective date is not practicable or reasonable, especially given that operators also are implementing the requirements of other significant new regulatory and statutory requirements.

The Associations also seek reconsideration of provisions that departed from GPAC recommendations, some of them unanimous, without providing supporting evidence or explanation. These provisions include the requirement to treat a crack or crack-like condition as an immediate repair condition if it has a predicted failure pressure of less than 1.25 times the MAOP and the requirement that operators monitor and mitigate effects of corrosive "constituents" in a gas stream. The GPAC recommendations were the product of a substantial amount of time and effort by everyone involved, including representatives of the public, state regulators and industry. Under the Administrative Procedure Act (APA) and Pipeline Safety Act, PHMSA's rejection of the GPAC recommendations and the adoption of different regulations requires a reasoned explanation and supporting evidence.

The Associations also seek reconsideration of the requirement that operators assume a reassessment safety factor of 5 or greater for the assessment interval when evaluating dents and other mechanical damage because this provision provides no discernable safety benefit established by PHMSA, and was not proposed, presented to the GPAC, or made subject to notice and comment. Similarly, the requirement to treat metal loss associated with high-frequency electric resistance welded seams as an immediate repair condition is unsupported by evidence and PHMSA did not respond to INGAA's comments and concerns about this provision.

Finally, the Associations request that PHMSA provide guidance and clarification of several complex requirements, in order to ensure that the agency's compliance expectations are clear. The Associations also request that PHMSA make technical corrections and clarifications to several regulations that appear to contain inadvertent errors.

III. Statutory Framework

When issuing final rules adopting new safety standards, PHMSA must comply with the requirements of the APA[3] and the Pipeline Safety Act.[4] Under the APA, a Final Rule is unlawful if it is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law."[5] This determination is informed by whether PHMSA's final rule reflects reasoned decision-making under APA principles and complies with the Pipeline Safety Act.

[3] 5 U.S.C. §§ 551-559 (2018).

[4] 49 U.S.C. §§60101-60143 (2018), as amended by The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020, Pub. L. No. 116-260, div. R, title I, § 108(a)(2), 134 Stat. 2221, 2223 (Dec. 27, 2020).

[5] 5 U.S.C. § 706(2)(A); *see Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

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

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

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

(A) identify the regulatory and nonregulatory options that the Secretary considered in prescribing a proposed standard;

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6 *State Farm*, 463 U.S. at 43 (citing *Burlington Truck Lines v. United States*, 371 U.S. 156, 168 (1962)) (vacating as arbitrary and capricious final rule that rescinded regulations without adequate explanation).

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

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

9 *State Farm*, 463 U.S. at 43 (vacating agency's rescission of regulation without adequate explanation); *Pub. Citizen v. FMCSA*, 374 F.3d 1209, 1216 (D.C. Cir 2004) (finding that agency's failure to consider statutory factor constituted a failure to consider an important aspect of the problem).

10 *Owner-Operator Indep. Drivers Ass'n*, 494 F.3d at 199 (citing *Solite Corp. v. EPA*, 952 F.2d 473, 484 (D.C. Cir. 1991)) (finding that agency's failure to disclose the methodology of the agency's operator-fatigue model for performing a crash-risk analysis when that model was the basis for the cost-benefit analysis used in the agency's Regulatory Impact Assessment violated APA's notice and comment requirements).

11 49 U.S.C. § 60102(a)(1) & (2).

12 *Id.* § 60102(b)(1).

13 *Id.* § 60102(b)(2).

14 *Id.* § 60102(b)(2)(E).

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

PHMSA also is required to provide "the risk assessment information and other analyses supporting each proposed standard" to the Technical Pipeline Safety Standards Advisory Committee, (*i.e.*, Gas Pipeline Advisory Committee (GPAC)), the federal advisory committee that reviews and provides recommendations on pipeline safety rulemaking proposals.[16] The GPAC is required to "prepare and submit to [PHMSA] a report on the technical feasibility, reasonableness, cost-effectiveness, and practicability of the proposed standard and include in the report recommended actions" within "90 days of receiving the proposed standard and supporting analysis."[17] PHMSA is then required to "publish each report, including any recommended actions and minority views." PHMSA is "not bound by the conclusions of the [GPAC]" on a proposed rule, but must "publish the reasons" for rejecting its conclusions.[18]

Disregarding the Pipeline Safety Act's statutorily-mandated factors and procedures when adopting a safety standard is arbitrary and capricious[19] and reflects a failure to consider an important aspect of the problem.[20] Moreover, these factors apply to each proposed safety standard, as evidenced by use of the singular noun "standard" throughout these provisions.[21]

IV. Petition for Reconsideration

Under § 190.335, any interested person may petition PHMSA for reconsideration of an issued regulation. The petition must contain "a brief statement of the complaint and an explanation as to why compliance with the rule is not practicable, is unreasonable, or is not in the public interest."[22] The Associations file this Petition to seek reconsideration of several specific

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15 *Id.* § 60102(b)(3).
16 *Id.* § 60115(c)(1)(A).
17 *Id.* § 60115(c)(2)
18 *Id.*
19 *Owner-Operator Indep. Drivers Ass'n*, 656 F.3d at 589 (vacating rule because agency failed to consider an issue it was statutorily required to address); *Pub. Citizen*, 374 F.3d at 1216 (D.C. Cir 2004) (vacating final rule for failing to consider impact of final rule on the health of drivers, a mandatory statutory consideration under organic statute). *Id.* (stating that "'the complete absence of any discussion' of a statutorily mandated factor 'leaves us with no alternative but to conclude that [the agency] failed to take account of the statutory limit on [its] authority,'" making the agency's reasoning arbitrary and capricious.") (quoting *United Mine Workers v. Dole*, 870 F.2d 662, 673 (D.C. Cir. 1989)).
20 *Pub. Citizen*, 374 F.3d at 1216.
21 *C.f., Am. Fed'n of Labor and Cong. of Indus. Orgs. v. OSHA*, 965 F.2d 962, 969 (11th Cir. 1992) (finding that, where statute required agency to establish permanent exposure limits for air contaminants in the workplace based on substantial evidence of the risk the contaminants posed to workers, agency was required to demonstrate that the PEL for each contaminant was supported, and that failure to make such demonstration was arbitrary and capricious).
22 49 C.F.R. § 190.335(a).

issues in order to ensure that the requirements of the Final Rule are clear, practicable, and reasonable.

A. The Associations request reconsideration of the Final Rule's nine-month effective date.

The effective date of most of the provisions in the Final Rule is May 24, 2023, merely nine months after the date of publication. The Associations request reconsideration of this effective date because requiring the implementation of complex new regulatory requirements, including newly incorporated industry standards, within nine months is not consistent with pipeline safety and is not practicable or reasonable. The Associations request that PHMSA provide operators 18 months to implement the comprehensive new requirements of the Final Rule.

The scope of the Final Rule is comprehensive and broad, and as explained in the Trade Associations' June 6, 2018 comments,[23] implementing the new requirements will be complex and time-consuming. In order to realize the full safety benefits of the new requirements that were eleven years in the making, PHMSA must permit operators the time necessary to implement them correctly and carefully. The additional time also will enable PHMSA staff to develop compliance guidance for both operators and inspectors.

Compliance with the Final Rule is not simple. Processes and procedures affected by new requirements include those related to operation, maintenance, emergency, integrity management, and operator qualification programs. Amending these procedures to reflect new regulations requires that operators examine processes across their systems and understand how they are affected by new requirements. An operator must amend existing procedures to reflect new processes, and in some cases, create new procedures. Revisions to one procedure often affect other procedures that may not be directly addressed by the new regulations. Subject matter experts from across various functions and disciplines must be consulted and revised procedures must be vetted by appropriate personnel, including operating staff and management. An operator also may have to update its information technology infrastructure, including data and document management systems, to accommodate new processes. Staff must be fully trained on the new procedures and, if necessary, qualified on new covered tasks under the operator's operator qualification program. In addition, an operator must develop and implement a management of change (MOC) process before implementing new procedures and processes.

The challenges of implementing the Final Rule's new requirements are exacerbated by the fact that operators also are simultaneously working to implement the requirements of other new significant regulatory and statutory requirements. PHMSA's recently issued Valves Final Rule becomes effective October 5, 2022 and requires compliance by April 10, 2023.[24] The

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[23] Comments on Pipeline Safety: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments Final Rule, filed by the American Gas Association, American Petroleum Institute, American Public Gas Association, and INGAA, Docket Nos. PHMSA-2016-0136, PHMSA-2011-0023, at 12 (June 6, 2018) (Comments of Trade Associations).

[24] Pipeline Safety: Requirements of Valve Installation and Minimum Rupture Detection Standards, Final Rule, 87 Fed. Reg. 20,940 (Apr. 8, 2022) (Valves Final Rule).

Valves Final Rule requires that operators, among other things implement enhanced valve maintenance procedures, including annual testing and response time drills, perform risk assessments and install rupture mitigation valves in HCAs if an operator determines it would efficiently protect an HCA. An operator also must implement new emergency response and post-accident procedures. Implementing the Valves Final Rule requires examination of processes, the development of new procedures, and the dedication of the same personnel who are now are called upon to implement this Final Rule.

In addition, operators continue their efforts to implement the requirements of the 2019 Gas Transmission Rule[25] and the 2020 PIPES Act.[26] Notably, the Final Rule amends several of the same provisions that were either amended or newly adopted in the 2019 Gas Transmission Rule, requiring that operators revisit and revise their implementation of those requirements. For example, the 2019 Gas Transmission Rule adopted § 192.712 addressing the analysis of predicted failure pressure. Operators have undertaken to implement that provision's requirements by evaluating processes and revising procedures. The Final Rule has further amended § 192.712, requiring operators to evaluate how the newly adopted provisions integrate with the 2019 language. In addition, newly adopted § 192.714, establishing repair criteria for pipeline segments not located in HCAs, also interrelates with the requirements of § 192.712. Changes to § 192.933 adopted in both the 2019 Gas Transmission Rule and the Final Rule present similar challenges.

Finally, operators are also continuing to implement § 114(b) of the PIPES Act which requires that operators update their inspection and maintenance plans to address eliminating hazardous leaks, minimizing natural gas releases, and replacing or remediating pipelines known to leak.[27]

Imposing a nine-month compliance schedule, which was not subject to notice and comment, and requiring operators to rush compliance efforts does a disservice to the goal of promoting pipeline safety and is not practicable or reasonable. Nine months does not reasonably accommodate all the work required to effectively implement the new requirements of the Final Rule and does not account for the existing compliance demands already placed on an operator's staff. Nine months also does not allow PHMSA staff adequate time to develop the guidance that operators and inspectors will need for effective compliance and enforcement.

The nine-month compliance deadline also is not practicable from a financial planning perspective. Budgets for 2023, which were planned and developed months ago, are now finalized. While the Associations actively participated in the GPAC meetings and the rulemaking process, the Final Rule's unanticipated departures from a number of GPAC recommendations are not accounted for in 2023 budgets. A nine-month compliance timeframe disrupts financial planning and a company's ability to execute on other important safety initiatives and is not consistent with pipeline safety.

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[25] 84 Fed. Reg. 52,180.

[26] The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020, Pub. L. No. 116-260, div. R, title I, § 108(a)(2), 134 Stat. 2221 (Dec. 27, 2020).

[27] 134 Stat. 2221, 2231.

For these reasons the nine-month implementation date is not practicable or reasonable. The Associations petition PHMSA to reconsider the Final Rule's nine-month implementation deadline and requests that PHMSA amend the Final Rule to provide operators 18 months from the date of publication to implement all provisions of the Final Rule.

B. The Associations request reconsideration of §§ 192.714(d)(1)(v)(C) and 192.933(d)(1)(v)(C) and requests that an operator is not required to treat a crack or crack-like condition as an immediate repair condition unless the predicted failure pressure is less than 1.1 times Maximum Allowable Operating Pressure (MAOP).

Maximum allowable operating pressure is defined as "the maximum pressure at which a pipeline or segment of a pipeline may be operated under" Part 192 of the pipeline safety regulations.[28] Sections 192.714(d)(1)(v)(C) and 192.933(d)(1)(v)(C) require that an operator of a gas transmission pipeline treat as an immediate repair condition any crack or crack-like anomaly that meets any one of several criteria, including that the anomaly "has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP."[29]

The Associations seek reconsideration of §§ 192.714(d)(1)(v)(C) and 192.933(d)(1)(v)(C) and requests that PHMSA amend the regulatory language to reflect the GPAC language which recommended a predicted failure pressure of 1.1 times MAOP. PHMSA's basis for adopting a predicted failure pressure of 1.25 times MAOP disregards the evidence supporting the GPAC recommendation, is inconsistent with existing regulations, and does not reflect reasoned decision-making.

The Final Rule acknowledges that the adopted predicted failure pressure of 1.25 times MAOP departs from the GPAC recommendation of 1.1 times MAOP after tool tolerance is verified.[30] This recommendation was unanimously agreed to after extensive discussion. PHMSA explains its decision to reject the GPAC recommendation as follows:

> PHMSA considered this suggestion but notes that, after allowing for pressure excursions above MAOP due to over pressure protection device settings, the actual safety margin of such an approach would be between 0 and 6 percent. PHMSA has determined that this safety margin for immediate crack conditions is inadequate and, for this final rule, has retained the requirement that operators must immediately repair crack anomalies with a predicted failure pressure that is less than 1.25 times MAOP.[31]

As the Associations understand this statement, PHMSA believes that a repair criterion of 1.1 times MAOP is not conservative enough because an operator has the ability to operate a pipeline segment above its established MAOP, which, in turn, reduces the safety margin associated with a predicted failure pressure. PHMSA's statement is inconsistent with multiple

[28] 49 C.F.R. § 192.3.
[29] Final Rule, 87 Fed. Reg. at 52,272, 52,277-78
[30] GPAC Meeting Final Voting Slides at 22 (March 26-28, 2018).
[31] Final Rule, 87 Fed. Reg. at 52,248.

Part 192 regulations that prohibit operating a pipeline segment at pressures higher than its MAOP and does not support PHMSA's decision to reject the GPAC recommendation. Moreover, PHMSA does not explain how it calculated a safety margin of 0 to 6 percent.[32]

Under § 192.619(a), an operator of a steel or plastic pipeline segment is prohibited from operating that segment at a pressure that exceeds its MAOP.[33] This prohibition also is reflected in numerous other provisions throughout PHMSA's Part 192 regulations. For example, under § 192.605(b)(5), an operator's written operations and maintenance procedures manual must contain a procedure addressing "[s]tarting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of operation of pressure-limiting and control devices."[34]

This build-up is allowed under § 192.201, a design regulation that governs the design of pressure relieving and limiting stations that pipelines install to prevent overpressuring a pipeline. Section 192.201(a) requires that

> Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following: . . . . (2) In pipelines other than a low pressure distribution system: (i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SYMS, whichever is lower.[35]

Section 192.201(a) applies only to pressure relieving or limiting devices and requires that they have the capacity to relieve gas in the pipeline the device is protecting should the pressure in the pipeline ever exceed MAOP plus ten percent. This design safeguard ensures that the pipeline does not rupture if operating pressure exceeds MAOP for some unintended reason. Section 192.201(a) does not govern the operation of pipelines and does not authorize a pipeline segment to operate at a pressure higher than the segment's MAOP.

The prohibition on operating a pipeline segment at a pressure that exceeds its MAOP also applies to compressor station piping. Similar to § 192.201, § 192.169(a) requires that each compressor station "have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent."[36]

PHMSA's assumption in the Final Rule that a pipeline segment is permitted to operate at pressures above MAOP via "pressure excursions above MAOP due to over pressure protection device settings,"[37] is inconsistent with long-standing regulations prohibiting a pipeline segment

[32] Agency decisions not supported by substantial evidence or do not reflect reasoned decision making are arbitrary and capricious under the Administrative Procedure Act. 5 U.S.C § 706(2)(A); *see State Farm*, 463 U.S. at 43.
[33] 49 C.F.R. § § 192.619(a).
[34] *Id.* § 192.605(b)(5).
[35] *Id.* § 192.201(a)(2)(i).
[36] *Id.* § 192.169(a).
[37] Final Rule, 87 Fed. Reg. at 52,248, 52,252.

from operating at pressures above MAOP. PHMSA's assumption is incorrect and the agency's basis for establishing a 1.25 times MAOP threshold for determining when a crack or crack-like anomaly must be treated as an immediate repair condition fails to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'"[38]

In support of the Final Rule, PHMSA also states that it took guidance from several sources, including ASME ST–PT–011 (''Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas''). PHMSA states that:

> In this final rule, operators can use an engineering analysis on cracks in Categories 1 through 2 as described above. However, any Category 3 or 4 cracking defect below 125 percent MAOP would require immediate remediation. Category 3 cracks would have a 10 percent or greater safety factor, which is similar to how PHMSA currently treats corrosion anomalies at § 192.933. PHMSA provides more conservatism in the cracking criteria because there is more uncertainty with the accuracy of current ILI [in-line inspection] technology in its ability to measure crack length and depth, as well operational factors.[39]

PHMSA's statement that Category 3 cracks require immediate remediation is incorrect. As the Final Rule states, and as also shown in Table 40 of ASME STP-PT-011, the remaining life of a Category 3 crack at MAOP is greater than 2 years.[40] That is not an immediate condition.

In addition, PHMSA's statement that it applied more conservatism for cracking because of perceived uncertainty of current in-line inspection (ILI) technology is speculative and does not acknowledge the lengthy GPAC discussions. During the March 2, 2018 GPAC meeting on this proposal, a GPAC member pointed out that operators demonstrate the accuracy of the ILI system through tools such as unity plots.[41] Unity plots compare "as found" conditions in an excavation to conditions "as called" made by the ILI and provide a basis for demonstrating the effectiveness of an ILI and for developing appropriate tolerances based on actual field measurements. The approach agreed upon by the GPAC members after a long discussion on conservatism, including the use of unity plots, was to enable use of 1.1 x MAOP, but to require accounting for tool tolerances.[42] This approach is consistent with § 192.712(e)(1) which places the burden on an operator to "analyze and account for uncertainties in reported assessment results . . . in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using *in situ* direct measurements."[43]

Finally, when applied in conjunction with the conservative default Charpy v-notch toughness values adopted in § 192.712(e)(2)(D) for pipeline segments with a history of crack or crack-like defects (adopted in the 2019 Gas Transmission Final Rule), the conservative repair

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[38] *State Farm*, 463 U.S. at 43.
[39] Final Rule, 87 Fed. Reg. at 52,248.
[40] *Id.* at 52,249.
[41] GPAC Meeting Transcript at pp. 257-59 (March 2, 2018) (Statement of Mr. Drake).
[42] GPAC Meeting Final Voting Slides at 22 (March 26-28, 2018) .
[43] 49 C.F.R. § 192.712(e)(1).

criterion of 1.1x MAOP (accounting to tool tolerances) results in layers of conservatism for which PHMSA has provided no supporting evidence or analysis and without explanation.

The Final Rule does not reflect reasoned decision-making because it fails to address either the GPAC discussion on unity plots, the conservatism reflected in the GPAC Recommendation, or existing § 192.712(e)(1). In this respect the Final Rule is inconsistent with the evidence before the agency and fails to consider an important aspect of the problem.[44] PHMSA also failed to consider relevant available pipeline safety information and to explain the reasons for rejecting the GPAC recommendation.[45]

PHMSA also has not demonstrated that adopting a predicted failure pressure of 1.25 times MAOP is appropriate, reasonable, or practicable and does not consider the factors required under the Pipeline Safety Act.[46] The Final Rule is inconsistent with existing regulations and does not explain why the GPAC recommendation was rejected.

The Associations request that PHMSA reconsider this provision and consistent with the GPAC recommendation, amend the language modify the threshold for requiring immediate repair of a crack or crack-like anomaly to be 1.1 times MAOP after tool tolerance is verified using the *in situ* direct measurements in § 192.712(e)(1).[47]

C. The Associations request reconsideration of the requirement in § 192.478 to develop and implement a program to "monitor and mitigate" effects of corrosive "constituents" in a gas stream.

New § 192.478(a) requires that "[e]ach operator of an onshore gas transmission pipeline with corrosive constituents in the gas being transported must develop and implement a monitoring and mitigation program to mitigate the corrosive effects, as necessary."[48] Section 192.478(a) identifies carbon dioxide, hydrogen sulfide, sulfur, microbes and liquid water "either by itself or in combination" as "[p]otentially corrosive constituents," and requires that an operator "evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe, and implement mitigation measures as necessary."[49]

Section 192.478(b) describes the required elements of an internal corrosion monitoring and mitigation program, which includes the "use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents" and "[t]echnology to mitigate the potentially corrosive gas stream constituents." An operator also must perform an annual evaluation "to ensure that potentially corrosive gas

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[44] *State Farm*, 463 U.S. at 43.
[45] 49 U.S.C. §§ 60102(b)(2), 60115(c)(2).
[46] *Pub. Citizen*, 374 F.3d at 1216 (finding that agency's failure to consider statutory factor constituted a failure to consider an important aspect of the problem).
[47] GPAC Meeting Final Voting Slides at 22 (March 26-28, 2018).
[48] Final Rule, 87 Fed. Reg. at 52,270 (to be codified at 49 C.F.R. § 192.478(a)).
[49] *Id.*

stream constituents" are monitored and mitigated effectively and annually review the program and implement adjustments as necessary based on program results.[50]

The Associations request that PHMSA reconsider the applicability of § 192.478(a) to transmission pipelines that transport gas containing "corrosive constituents." The regulation should instead apply to pipelines transporting "corrosive gas," consistent with existing long-standing regulations.[51] The Final Rule departs from the GPAC recommendation without providing the explanation required under the Pipeline Safety Act, is not based on evidence in the record, and does not reflect reasoned decision-making. The provision is impracticable and unreasonable. The Associations also petition for reconsideration of § 192.478(b) and requests that PHMSA clarify that operators will be permitted to develop and implement monitoring plans that are tailored to the operations of their individual systems

In the Notice of Proposed Rulemaking (NPRM), PHMSA proposed to require that an operator of an onshore gas transmission pipeline develop and implement a monitoring and mitigation program "to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects."[52] The proposal was the topic of extensive discussion at the January 11, 2017 and June 6, 2017 GPAC meetings.[53] GPAC members raised several points regarding the proposal, including that (1) data collected at isolated receipt points do not represent the composition of a commingled gas stream;[54] (2) operators use multiple methods to monitor a gas stream, such as sampling, information from suppliers, and reliance on tariff provisions, that do not require the monitoring gas at individual receipt points;[55] (3) the presence of corrosive constituents by themselves do not cause internal corrosion unless water is present and that this is the reason why pipelines have dewpoint requirements;[56] and (4) interstate natural gas pipelines have FERC Gas tariffs that establish gas quality specifications for the corrosive constituents identified in the proposed rule.[57] GPAC members requested that PHMSA provide data supporting the proposal and clarify the magnitude of the problem.[58]

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50 *Id.*

51 *See* 49 C.F.R. § 192.475(a) which prohibits an operator from transporting corrosive gas "unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion," and § 192.477 which requires that if corrosive gas is transported, an operator must use "coupons or other suitable means . . . to determine the effectiveness of the steps taken to minimize internal corrosion."

52 Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Notice of Proposed Rulemaking, 81 Fed. Reg. 20,722, 20,830 (Apr. 8, 2016) (proposed § 192.478(a)).

53 GPAC Meeting Transcript at pp. 270-293 (January 11, 2017); GPAC Meeting Transcript at pp. 176-235 (June 6, 2017).

54 GPAC Meeting Transcript at p. 279 (January 11, 2017) (Statement of Mr. Zamarin).

55 GPAC Meeting Transcript at pp. 281-82; 291 (January 11, 2017) (Statements of Ms. Campbell and Ms. Fleck); GPAC Meeting Transcript at p. 220 (June 6, 2017) (Statement of Mr. Drake).

56 GPAC Meeting Transcript at pp. 210-11 (June 6, 2017) (Statement of Mr. Zamarin).

57 GPAC Meeting Transcript at p. 274 (January 11, 2017) (Statement of Ms. Campbell); GPAC Meeting Transcript at p. 188 (June 6, 2017) (Statement of Mr. Zamarin).

58 GPAC Meeting Transcript at pp. 273, 278 (January 11, 2017) (Statements of Ms. Campbell and Mr. Zamarin).

The approved GPAC recommendation was that § 192.478(a) be modified to apply to gas transmission pipelines that transport "corrosive gas,"[59] not corrosive constituents. The reference to "corrosive gas" is consistent with other regulations addressing internal corrosion and, importantly, reflects the desire of PHMSA's Associate Administrator for Pipeline Safety to adopt language that is consistent with existing provisions already addressing internal corrosion.[60] For example, § 192.475 prohibits the transportation of corrosive gas unless the corrosive effect of the gas is investigated and minimized, and § 192.477 requires that an operator assess the effectiveness of measures taken to minimize internal corrosion.[61] Even the Final Rule's preamble states that new § 192.478(a) would apply to pipelines transporting "corrosive gas."[62]

The Final Rule rejects the GPAC's recommendation and instead of applying to transmission pipelines transporting corrosive gas, applies to transmission pipelines that transport gas "with corrosive constituents." The Final Rule does not address the issues raised by GPAC members and provides no explanation for rejecting the GPAC recommendation as required under the Pipeline Safety Act.[63]

Without addressing GPAC members' descriptions of how they already monitor and manage corrosive constituents in the gas, the Final Rule assumes that any gas stream containing corrosive constituents is a corrosive gas. This assumption is incorrect and does not account for the conditions that must exist for corrosive constituents to become harmful. For example, and as pointed out during the GPAC discussion, without liquid water, neither carbon dioxide nor hydrogen sulfide are corrosive.[64]

The Final Rule also does not account for the common practice of mixing gas streams on interstate natural gas pipelines. This practice enables operators to manage the gas transported in its pipelines and effectively mitigate potential harmful effects corrosive constituents. Interstate natural gas pipelines receive gas at various points throughout their pipeline systems, including from gathering systems, market hubs, and other transmission pipelines. The composition of the gas received into a pipeline system will vary (*e.g.*, volumes, pressures, and quantity of corrosive constituents). Any corrosive constituents that may be in a particular gas stream are mixed with other flowing gas on the pipeline to mitigate any harmful effects. Mixing corrosive constituents in the gas stream is a practice that is encouraged by the Federal Energy Regulatory Commission (FERC), the federal agency that regulates the interstate transportation of gas under the Natural Gas Act.[65] FERC policy encourages mixing gas streams because it maximizes the available of natural gas supplies to the market for the benefit of end-users and consumers across the country.

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[59] GPAC Meeting Final Voting Slides at pp. 32 (June 6-7, 2017). *See also* GPAC Meeting Transcript at pp. 199-200 (June 6, 2017) (Statement of Mr. Nanney) ("If corrosive gas is being transported," that's the key. We're not using non-dry gas, we were using "if corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion.").

[60] GPAC Meeting Transcript at pp. 223-24 (June 6, 2017) (Statement of Mr. Mayberry).

[61] 49 C.F.R. §§ 192.475(a), 192.477.

[62] Final Rule, 87 Fed. Reg. at 52,237-38, 52,258.

[63] 49 U.S.C. § 60115(c)(2).

[64] GPAC Meeting Transcript at pp. 210-11 (June 6, 2017) (Statement of Mr. Zamarin).

[65] 15 U.S.C. §§ 717-717z (2018).

The Final Rule does not acknowledge the fact that FERC is the federal agency with regulatory authority over the quality of the gas transported on interstate natural gas pipelines. Each interstate pipeline has a FERC-approved Gas Tariff that contains gas quality specifications.[66] A pipeline is required to accept gas that meets those gas quality specifications and requires permission from FERC to modify them. While these specifications vary from pipeline to pipeline depending on operating circumstances and market conditions, each FERC tariff contains a safe harbor for corrosive constituents, such as H_2S, CO_2 and water. This means that pipelines receive gas containing these constituents as a matter of course as part of normal operations. The Final Rule's requirement that an operator "evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe" and use "gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents,"[67] is at odds with the requirement that operators accept gas that fall within the safe harbors established in each interstate pipeline's FERC Gas Tariff.

The Final Rule's assumptions that transmission pipeline operator "have monitoring systems for the quality of the gas entering their systems" is not supported by the record.[68] This statement echoes PHMSA's statements during the GPAC meetings that operators monitor the gas coming onto their systems because "they're either paying or getting paid based on the quality of that gas."[69] This statement is incorrect. Operators measure the hydrocarbon content of gas, including methane, ethane, *etc.*, because those constituents contribute to the heating value of the gas, which when combined with the volume of gas, produces the number of dekatherms. Dekatherms are the value basis for payment for transporting gas.

Section 192.478(a) is based on unsupported assumptions about the risks associated with transporting gas containing corrosive constituents, and does not acknowledge pipelines' operating practices or other regulatory requirements that govern pipeline operations. PHMSA has not reconciled its assumptions about the effects of transporting gas containing corrosive constituents with the information provided by GPAC members and has not explained how the expansive scope of § 192.478(a) is supported by record evidence as required under the APA.[70] PHMSA also has not considered the appropriateness of the standard for the type of facility or the information received from the public and the GPAC, as required under the Pipeline Safety Act.[71]

Requiring an operator to implement a monitoring and mitigation program because the gas stream contains "corrosive constituents" is inconsistent with requirements in § 192.475 which addresses internal corrosion based on "corrosive gases." § 192.475(a) addresses control of corrosive gas by requiring that:

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[66] GPAC Meeting Transcript at p. 274 (January 11, 2017) (Statement of Ms. Campbell); GPAC Meeting Transcript at p. 188 (June 6, 2017) (Statement of Mr. Zamarin).
[67] Final Rule, 87 Fed. Reg. at 52,270.
[68] *Id.* at 52,238.
[69] GPAC Meeting Transcript at p. 192 (June 6, 2017) (Statement of Mr. Nanney); GPAC Meeting Transcript at p. 290 (January 11, 2017) (Statement of Mr. Nanney) (stating "I would be very surprised if H_2S, CO_2, all the issues for corrosive gas are not being monitored, because that also has to do with how much you pay on the cash register.").
[70] *State Farm*, 463 U.S. at 43, *Nat'l Fuel Gas Supply Corp.*, 468 F.3d at 839, 843 (vacating agency rule because record evidence did not support existence of the problem the rule purported to address).
[71] 49 U.S.C. § 60102(b).

"Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been *investigated* and *steps have been taken to minimize* internal corrosion."[72]

The Final Rule also reflects a rejection of the agreed-upon GPAC recommendation that would limit proposed § 192.478 to onshore gas transmission pipelines that transport "corrosive gas."[73] The Final Rule does not explain why PHMSA departed from the GPAC recommendation as required under the Pipeline Safety Act.[74]

The Associations also petition for reconsideration of § 192.478(b) and requests that PHMSA clarify that operators will be permitted to develop and implement monitoring plans that are tailored to the operations of their individual systems. Monitoring plans will vary depending on a number of factors, including the geographic locations of receipt points and the source and volume of the gas coming in at these points (*i.e.*, a pooling point, a gathering pipeline, a storage facility, market hubs, pipeline interconnects) vs. the volume of gas transported in the mainline receiving the gas. Other relevant factors include the proximity of processing or treatment facilities, the volume of the receipt point, the potential impact of the receipt point on downstream facilities, and operational characteristics of the pipeline, such as operating pressure. Operators also need to have flexibility with respect to the types of monitoring methods they use, and if they use equipment, their locations.

D. The Associations request that PHMSA reconsider § 192.712(c)(9)'s requirement that operators assume a reassessment safety factor of 5 or greater when evaluating dents and other mechanical damage.

Existing § 192.712 describes how a transmission pipeline operator must determine the predicted failure pressure at the location of an anomaly or defect and the remaining life of a pipeline segment at the location of the anomaly or defect. PHMSA adopted this provision in the 2019 Gas Transmission Rule,[75] but left subsection 192.712(c) "reserved." In the Final Rule, PHMSA now adopts § 192.712(c), which addresses dents and other mechanical damage.[76]

Section 192.712(c)(9) states in relevant part:

(c) *Dents and other mechanical damage.* To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows: . . . .(9) Using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and <u>assuming a reassessment safety factor of 5 or greater for the assessment interval</u>, estimate the fatigue life of

[72] 49 C.F.R. § 192.475(a) (emphasis added).
[73] GPAC Meeting Transcript at pp. 176-77 (June 6, 2017) (Statement of Mr. Nanney); s*ee also* GPAC Meeting Final Voting Slides at 32 (June 6-7, 2017).
[74] 49 U.S.C. § 60115(c)(2).
[75] 84 Fed. Reg. at 52,205-06.
[76] Final Rule, 87 Fed. Reg. at 52,271.

> the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment intervals in accordance with this section.[77]

The Associations request reconsideration of the requirement that operators assume a reassessment safety factor of 5 or greater for the assessment interval when evaluating dents and other mechanical damage. The record contains no basis for this language. It was not proposed in the NPRM or discussed by GPAC. In fact, it is inconsistent with language PHMSA itself proposed during the GPAC meeting. As a result, the GPAC did not discuss it or provide a recommendation on it. The Final Rule omits consideration of the safety benefit of the change in the safety factor. Section 192.712(c)(9) is not supported by substantial evidence and is arbitrary and capricious.[78]

The first mention of establishing reassessment factor occurred at the March 28, 2018 GPAC meeting. In response to comments previously received suggesting that PHMSA allow operators to use engineering critical assessments (ECA) to evaluate dents, PHMSA set forth a proposed approach. PHMSA's proposal was to "[e]stimate the fatigue life of the dent using [Finite Element Analysis (FEA)] with the operational pressure data and different fatigue life prediction models, which must have a reassessment *safety factor of 2*."[79] The transcript for the meetings on March 27 – 28, 2018 reflects that no GPAC member commented or objected to PHMSA's proposed approach.

The Final Rule's language requiring a safety factor of 5 is a significant departure from the proposed safety factor of 2 that PHMSA recommended at the March 27, 2018 GPAC meeting. PHMSA provides no explanation for adopting language that was not proposed in the NPRM, was not discussed by the GPAC and was not made available for public notice and comment. The impact of this change is to significantly increase the required frequency for performing a fatigue analysis and require reassessments of subject dents sooner without any discernable safety benefit justifying making an operator devote resources to non-critical safety tasks.

The Associations petition PHMSA to reconsider language in § 192.712(c)(9) adopting a safety factor of 5. PHMSA adopted this language without providing an opportunity for public notice and comment in violation of the APA.[80] The proposal is not the logical outgrowth of a proposal contained in the NPRM,[81] lacks record support, and does not reflect reasoned decision-making.[82] PHMSA's adoption of this language also is inconsistent with the rulemaking procedures of the Pipeline Safety Act because PHMSA has failed to consider relevant available gas pipeline safety information, the appropriateness of the standard for the type of transportation

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77 *Id.* (underlining added for emphasis).
78 *Owner-Operator Indep. Drivers Ass'n*, 656 F.3d at 588 (applying *State Farm* standard and vacating final rule as arbitrary and capricious).
79 GPAC Meeting Slides at 149 (March 26-28, 2018) (emphasis added), *see also* GPAC Meeting Transcript at pp. 296-97 (March 27, 2018) (Statement of Mr. Nanney).
80 *Owner-Operator Indep. Drivers Ass'n*, 656 F.3d at 588.
81 *Nat'l Lifeline Ass'n v. FCC*, 921 F.3d 1102, 1116 (D.C. Cir 2019).
82 *State Farm*, 463 U.S. at 52.

or facility, reasonableness, comments and information received from the public, and comments and recommendations of the GPAC.[83]

E. The Associations request that PHMSA reconsider §§ 192.714(d)(1)(iv) and 192.933(d)(1)(iv) to remove the requirement that operators treat metal loss affecting a longitudinal seam on a high-frequency electric resistance welded pipe as an immediate repair condition.

The Associations request reconsideration of the requirement in § 192.714(d)(1)(iv) and § 192.933(d)(1)(iv) that operators treat as an immediate repair condition metal loss "preferentially affecting a detected longitudinal seam, if that seam was formed by . . . high-frequency electric resistance welding . . . and the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP."[84] PHMSA has provided no data or analysis supporting this requirement and did not respond to concerns raised by INGAA and GPAC members during the GPAC meeting. These new regulatory requirements do not promote safety and are not practicable or reasonable.

This requirement originated in the NPRM's proposal to require that operators treat as an immediate condition, "[a]n indication of metal-loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high-frequency, electric resistance welding or by electric flash welding."[85]

In comments on the NPRM, INGAA explained that PHMSA had not explained or provided data supporting the proposal to treat metal loss associated with high-frequency electric resistance welded (HF-ERW) seams as an immediate repair condition.[86] INGAA pointed out that the proposal was inconsistent with Section 7.2.1 of B31.8S-2004 which does not treat HF-ERW seams as an immediate repair condition.[87] INGAA requested that PHMSA remove the proposal to treat as an immediate repair condition metal-loss affecting a detected longitudinal seam if the seam was formed by high-frequency electric resistance welding.

At the March 2, 2018 GPAC Meeting, PHMSA responded to comments on proposed § 192.933(d)(1)(v) that had requested PHMSA to (1) allow operators to perform fitness for service evaluations, and (2) clarify that the proposed regulation applies to selective seam weld corrosion rather than general corrosion crossing the seam weld.[88] PHMSA indicated that "[b]ased on incident investigation, experience, and data, it believes the proposed repair criteria is appropriate and inclusion of HF-ERW pipe seam welds in § 192.933(d)(1)(v) is appropriate."[89]

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83 49 U.S.C. § 60102(b)(2).
84 Final Rule, 87 Fed. Reg. at 52,271-72, 52,277-78 (to be codified at 49 C.F.R. § 192.714(d)(1)(iv) and 192.933(d)(1)(iv)).
85 81 Fed. Reg. at 20,839 (proposed § 192.713(d)(1)(iv) and § 192.933(d)(1)(v)).
86 Comments of INGAA on NPRM at 91-92 (July 7, 2016).
87 *Id. See also* ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," Sec. 7.2.1 (2004) (Incorporated by reference into Part 192. 49 C.F.R. § 192.7).
88 GPAC Meeting Slides at 58 (March 2, 2018).
89 GPAC Meeting Transcript at pp. 204-05 (March 2, 2018) (Statement of Mr. Nanney). GPAC Meeting Slides at 58 (March 2, 2018).

According to PHMSA, between 2010 and November 2017, ten pipe seam failures had occurred on high-frequency ERW pipe.[90]

At the March 2, 2018 GPAC meeting, INGAA recommended that metal loss affecting the long seam for HF-ERW pipe be removed as an immediate repair condition, noting that INGAA's analysis of data from 2010 to 2017 indicated that "there have been zero corrosion or environmental corrosion cracking, which are metal loss incidents affecting the long seam of high frequency ERW pipe."[91] A GPAC member requested more data regarding the cause of such failures before "declaring metal loss in high frequency seams a critical immediate anomaly."[92] Comments filed by the Associations after the March 2, 2018 GPAC meeting reiterated the recommendation that metal loss affecting a HF-ERW seam be removed as an immediate repair condition.[93]

At the March 27, 2018 GPAC meeting, PHMSA suggested "allowing, but not requiring, ECA analysis for the evaluation of corrosion metal loss affecting the long seam . . . . If the predicted failure pressure is less than 1.25 times the MAOP, the anomaly would be an immediate condition."[94] PHMSA also stated that it would add the word "preferentially to assure that this criterion would not be applied to small corrosion pits near long seam. It would only apply to corrosion along the seam that could lead to slotting-type crack-like defects."[95]

INGAA responded by reiterating that:

> [T]here's a criteria proposed to a requirement related to metal loss affecting the long seam. And we went back and looked at data from 2010 to 2017 and found zero corrosion or environmental corrosion metal loss incidents affecting the long seam of high frequency ERW pipes. Those pipes are not known to be particularly susceptible to this type of corrosion, so based on that incident review and our knowledge of this type of seam, we don't think high frequency ERW pipes should be included in the response and repair requirements related to metal loss preferentially affecting the long seam.[96]

The Final Rule adopts § 192.714(d)(1)(iv) and § 192.933(d)(1)(iv) with virtually no explanation. Without citing any supporting evidence or analysis, PHMSA asserts that HF-ERW pipe is among the seam types "known to be susceptible to latent manufacturing defects."[97] PHMSA does not address the comments of INGAA and other operators that pointed out that

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[90] GPAC Meeting Slides at 59 (March 2, 2018).
[91] GPAC Meeting Transcript at p. 242 (March 2, 2018) (Statement of Mr. Osman).
[92] *Id.* at pp. 258-59 (Statement of Mr. Drake).
[93] Comments on PHMSA Gas Pipeline Advisory Committee (GPAC) Teleconference Held March 2, 2018 filed by the American Gas Association, API, American Public Gas Association and INGAA at 12 (Mar. 9, 2018).
[94] GPAC Meeting Transcript at p. 308 (March 27, 2018) (Statement of Mr. McLaren). *See also* GPAC Meeting Transcript at p. 20 (March 28, 2018) (Statement of Mr. McLaren), GPAC Meeting Slides at 167 (March 26-28, 2018).
[95] GPAC Meeting Transcript at p. 309 (March 27, 2018) (Statement of Mr. McLaren) (stating "PHMSA suggests inserting the word preferentially to assure that this criterion would not be applied to small corrosion pits near a long seam. It would only apply to corrosion along the seam that could lead to slotting-type, crack-like defects.").
[96] GPAC Meeting Transcript at pp. 127-28 (March 28, 2018) (Statement of Mr. Osman).
[97] Final Rule, 87 Fed. Reg. at 52,261 & n.53.

PHMSA has not demonstrated that such pipe *is* susceptible to corrosion in the long seam and does not explain its analysis of the incident data cited during the GPAC meeting. PHMSA also does not account for the costs and benefits of this provision in its Final Regulatory Impact Statement in violation of the Pipeline Safety Act.[98]

Not only are PHMSA's assertions regarding HF-ERW pipe unsupported and inaccurate, but they have practical implications for operators who will be required to prioritize and direct resources to pipe with HF-ERW seams, when those resources may be more effectively directed to pipe that poses much higher risk.

The Final Rule is inconsistent with record evidence and does not reflect reasoned decision making.[99] PHMSA has failed to reveal the technical basis for this provision.[100] Requiring that operators treat metal loss affecting a longitudinal seam on HF-ERW as an immediate repair condition is not practicable or reasonable and the Associations request that PHMSA revise § 192.714(d)(1)(iv) and § 192.933(d)(1)(iv) to remove the reference to high-frequency electric resistance welded pipe.

F. The Associations request PHMSA to reconsider and amend § 192.473(c)(4) to allow an operator to notify PHMSA of the need for additional time under § 192.18 if the operator is unable to complete remedial actions to address stray currents within 15 months of completing an interference survey.

Under § 192.473, an operator whose pipeline is subject to stray currents must have a continuing monitoring plan to minimize the detrimental effects of such currents.[101] The Final Rule amends § 192.473 to require that an operator's continuing program provide for performing interference surveys, analyzing the results of the survey, developing a remedial action plan to correct certain types of interference currents, and applying for any necessary permits within 6 months of completing the survey that identified the deficiency.[102] Section 192.473(c)(4) requires that an operator "complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency, or as soon as practicable, but not to exceed 6 months after obtaining any necessary permits."[103]

The Associations request reconsideration of § 192.473(c)(4)'s requirement to complete stray current remedial actions within 15 months after completing the interference survey. Because of the nature of stray currents and the length of time over which their potential detrimental effects are observed and measured, an operator may not have the ability to complete

[98] 49 U.S.C. § 60102(b)(2).
[99] *Nat'l Fuel Gas Supply*, 468 F.3d at 839, 843 (vacating agency rule because record evidence did not support existence of the problem the rule purported to address).
[100] *Owner-Operator Indep. Drivers Ass'n*, 494 F.3d at 199 (citing *Solite Corp. v. EPA*, 952 F.2d 473, 484 (D.C. Cir. 1991)) (finding that agency's failure to disclose the methodology of the agency's operator-fatigue model for performing a crash-risk analysis when that model was the basis for the cost-benefit analysis used in the agency's Regulatory Impact Assessment violated APA's notice and comment requirements).
[101] 49 C.F.R. § 192.473.
[102] Final Rule, 87 Fed. Reg. at 52,273 (to be codified at § 192.473).
[103] *Id.* at 52,269-70 (to be codified at § 192.473(c)(4)).

remedial actions within 15 months. In addition, mitigation can be an iterative process. An operator can measure and evaluate interference levels and install mitigation and yet not achieve anticipated mitigation. This requires additional measurement and evaluation to determine a modified interference mitigation design requiring more analysis and additional time.

Interference can result from proximity to other pipelines, sources of alternating current interference such as high voltage power lines, and direct current such as rail transportation. In mitigating interference where the sources of interference are known an operator will develop a design to address the interference. The operator will install and operate mitigation technology as the pipe is installed and evaluate interference as cathodic protection is installed in the year that follows completion of construction.[104] As the pipeline is placed into operation and the cathodic protection system is balanced, the operator will monitor interference levels. This can entail developing monitoring plans to evaluate when interference levels change as well as peak.

One of the challenges an operator can face is getting data from a power transmission or rail operator on the nature of the interference and so it takes time for the operator to collect and evaluate data. Monitoring can require data collection over a full year to understand the range of interference levels. For example, interference can be seasonal, intra-day, etc, which has the effect of requiring more than 15 months to mitigate. Consequently, the 15-month time frame for remediating interference currents may not be practicable.

The Associations request that PHMSA amend the regulation to require that an operator complete remedial actions within 15 months of performing the interference survey, subject to the ability to notify PHMSA of the need for and the duration of a time extension under § 192.18. This amendment would recognize that addressing the effects of stray currents can occur over a time period that exceeds 15 months.

G. The Associations request that PHMSA clarify that the language in § 192.710(a)(2) and § 192.624(a)(2)(iii) referring to pipeline segments that "can accommodate inspection by means of an instrumented inline inspection tool" refers to free-swimming tools, *i.e.*, tools that do not require facility modification.

The Associations request that PHMSA clarify how the new definition of "in-line inspection (ILI)" will be applied under § 192.624(a)(2)(iii) and § 192.710(a)(2) with respect to pipeline segments located in moderate consequence areas (MCA) that can accommodate an ILI. Specifically, the Associations request that PHMSA clarify that the term "instrumented inline inspection tool" refers to free-swimming tools, *i.e.*, tools that do not require permanent modification to the pipeline facility.

The NPRM proposed to define the term "in-line inspection" as "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*."[105] During the March 27, 2018 GPAC meeting, PHMSA and the GPAC agreed to further clarify the proposed definition by adding the following sentence stating

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[104] 49 C.F.R. § 192.455(a)(2).
[105] 81 Fed. Reg. 20,722 at 20,805 (emphasis added).

"[t]his definition includes tethered and self-propelled inspection tools."[106] Several GPAC members expressed concern that existing language in § 192.710 and § 192.624 that refers to pipelines located in MCAs that can accommodate ILIs could be interpreted to require that an operator make permanent facility modifications to accommodate ILI tools.[107]

To address this concern, PHMSA agreed to include language in the Final Rule's preamble that clarifies that the applicability language in § 192.710 and § 192.624 is limited to pipeline segments that can accommodate free-swimming ILIs, *i.e.*, tools that can be deployed without the pipeline having to be modified to accommodate an ILI.[108] The voting slides for the March 27, 2018 GPAC meeting reflect that PHMSA would "[c]onsider adding 'free-swimming' to the definition for 'pipe segment can accommodate inspection by means of an instrumented in-line inspection tool.'"[109]

In the Final Rule, PHMSA adopted a definition of "in-line inspection" that is based on definitions in NACE SP0102-2010, including the sentence stating that the definition "includes tethered and self-propelled inspection tools."[110] While the Final Rule states that "an ILI can include both tethered and self-propelled (*i.e.*, 'free-swimming') tools,"[111] the preamble does not clarify that the applicability language in § 192.710 and § 192.624 is limited to pipeline segments that can accommodate free-swimming ILIs, *i.e.*, tools that do not require modification to accommodate an ILI.

The Associations support the new definition of ILI, but requests that PHMSA adopt an FAQ making clear that the new definition is not to be interpreted to require that operators use ILI tools that require permanent modifications to pipeline facilities, thereby expanding the applicability of § 192.710 and § 192.624. Section 192.710 sets forth requirements for assessments outside of HCAs. Section 192.624 addresses reconfirming MAOP for onshore steel transmission lines. Both sections, which were adopted in the 2019 Gas Transmission Rule,[112] apply to pipeline segments located in MCAs "if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool."[113] Addressing the meaning of "piggable" in the preamble for that final rule, PHMSA recounted that during the GPAC meetings it had noted that a "piggable line" would be one without physical or operational modifications.[114]

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106 GPAC Meeting Slides at 126 (March 26-28, 2018).
107 GPAC Meeting Transcript at pp. 209-215 (March 27, 2018).
108 GPAC Meeting Transcript at pp. 198, 205 (March 27, 2018) (Statement of Mr. McLaren).
109 GPAC Meeting Final Voting Slides at 13 (March 26-28, 2018).
110 Final Rule, 87 Fed. Reg. at 52,267 (to be codified at 49 C.F.R. § 192.3).
111 *Id.* at 52,256.
112 84 Fed. Reg. 52,180.
113 49 C.F.R. §§ 192.624 and 192.710.
114 2019 Gas Transmission Rule, 84 Fed. Reg. at 52,227 ("[t]he GPAC, based on a comment made by a member of the public, asked if PHMSA could provide more guidance on what a 'piggable' line is, for the purposes of the [MCA] definition. The GPAC asked whether PHMSA believed that qualifier applies to pipelines that can be fully assessed by a traditional, free-swimming ILI tool without further modification to the pipeline, and PHMSA noted during the meeting that a 'piggable' line would be one without physical or operational modifications.") The 2019 Gas Transmission Rule also stated that a line is piggable "if it can accommodate an instrumented ILI tool without the need for major physical or operational modification, other than the normal operational work required by the process of performing the inline inspection." *Id.* at 52,215.

The Associations' requested clarification is important to ensure that the term "instrumented inline inspection tool" in § 192.710 and § 192.624 refers to free-swimming tools, *i.e.*, tools that can be deployed without requiring permanent modification to the pipeline facility. Without this clarification, pipeline operators would face the risk that § 192.710 and § 192.624 may be interpreted to require that an operator physically modify a pipeline facility to accommodate ILI tools. The result would be to require an operator to modify currently unpiggable lines to make them piggable, thereby increasing the amount of pipeline mileage subject to § 192.710 and § 192.624. Such an outcome would not be practicable or reasonable and was not contemplated during the rulemaking process or analyzed in PHMSA's Final Regulatory Impact Analysis. Such an outcome also would be contrary to the GPAC expectations without providing any reason for rejecting GPAC's conclusion.[115]

H. The Associations request reconsideration of § 192.714(b) to allow operators to use values for Charpy v-notch toughness consistent with § 192.712(d)(3).

Section 192.714 sets forth the repair criteria for onshore transmission pipelines not located in an HCA. Section 192.714(b) states the following:

> A pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, and operator must obtain the undocumented data through § 192.607.[116]

This language requires that (1) if a given anomaly is predicted to have a very low failure pressure using the excessively conservative process as defined in § 192.712, an operator would have to reduce the pressure to the calculated failure pressure, even if the anomaly is not an imminent risk as demonstrated by the fact that the anomaly has not failed at normal operating pressure, and (2) if traceable, verifiable and complete records documenting data that is required to perform a predicted failure pressure analysis is not available, the operator must obtain the undocumented data using the material verification process in § 192.607.

This language, however, is not consistent with language in § 192.712 which allows an operator to use existing toughness data. Specifically, § 192.712 describes how a transmission pipeline operator is required to determine the predicted failure pressure at the location of an anomaly or defect and the remaining life of a pipeline segment at the location of the anomaly or defect. Section 192.712(d), which was adopted in the 2019 Gas Transmission Rule,[117] addresses cracks and crack-like defects. More specifically, § 192.712(d)(3) provides in part that:

> If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch

[115] 49 U.S.C.§ 60115(c)(2).
[116] Final Rule, 87 Fed. Reg. at 52,271.
[117] 84 Fed. Reg. at 52,271.

> toughness values based upon minimum operational temperature and equivalent to a full-size specimen value: (i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer . . . (iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with § 192.18.[118]

Charpy v-notch toughness values were discussed extensively at the GPAC meetings that led to the Final Rule and to the 2019 Gas Transmission Rule. The language codified in § 192.712(d)(3) allowing the use of values from comparable pipe or other values an operator can demonstrate provide a conservative Charpy v-notch toughness value reflects the outcome of those GPAC discussions and the GPAC recommendation.

Allowing an operator the flexibility to use comparable or other appropriate values is important from a practical perspective because no technology exists to measure toughness, including Charpy toughness, through non-destructive evaluation (NDE) (*i.e.*, testing) in an excavation. The only way to determine toughness is to cut out the pipe and test it in a laboratory or use comparable values like those permitted in § 192.712(d)(3). Having to perform a test in order to complete a repair for an excavated pipe is not practicable or reasonable. It does not promote safety when comparable data provides reasonable and safe Charpy toughness values. Furthermore, the requirement to reduce pressure during repairs based on the predicted failure pressures calculated using § 192.712 constitutes an unreasonable burden since the low calculated failure pressures are principally a result of the very conservative requirements in § 192.712 and do not reflect the true failure pressure of the anomaly.

The Associations request reconsideration of § 192.714(b) to permit an operator to apply the same process for determining Charpy v-notch toughness values as permitted under § 192.712(d)(3). PHMSA has not identified any basis for having two different processes for determining the predicted failure pressure of an anomaly or defect. Rather, the Associations believe that its request is consistent with PHMSA's intention of establishing consistent approaches in the two regulations. The Associations request that the language of § 192.714(b) be amended as follows:

> A pipeline segment's operating pressure must be reduced to a safe pressure established using sound engineering principles during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, and operator must <u>follow the procedures set forth in § 192.712(d)(3)</u>~~obtain the undocumented data through § 192.607~~.

In addition, the Associations request clarification on use of toughness values. While the § 192.712 often refers to Charpy toughness, the language related to the general requirements of

118 49 C.F.R. § 192.712(d)(3).

§ 192.712 describes the use of crack assessment models, including use of proven fracture mechanics models as below:

> When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).[119]

Many of the proven fracture mechanics models as required by the code, use material fracture toughness (not Charpy V-notch impact energy) as an input. This is because fracture toughness testing results better reflect the quasi-static (slow progressing) crack propagation behavior in pipeline steels than the Charpy V-notch method, which is a dynamic load test and measures the impact energy a material can absorb. If Charpy are the only data available, an operator must use a correlation that relates Charpy to another metallurgical toughness measures.

The Associations request that PHMSA clarify that other methods of toughness used in proven fracture mechanics models can be used within the modeling framework established in § 192.712(d)(1). This will include fracture toughness testing methods such as ASTM E1820 or BS 8571, *i.e.*, measures of toughness as specified by many of the proven models.

In addition, when PHMSA promulgated 2019 Gas Transmission Final Rule, and § 192.712(e)(2)(D) that established default Charpy toughness values for segments with a history of reportable incidents caused by cracking or crack-like defects, the Associations were unaware that PHMSA would not adopt the GPAC's unanimous recommendation to adopt 1.1 x MAOP including after tool tolerance has been field verified and applied.[120] Furthermore, pipeline operators did not have the data necessary to evaluate the impact of these default values as crack ILI tools were not as broadly used. The bases for these toughness default values was unclear, but the Associations had no reason to believe that PHMSA would reject the GPAC recommendation. With PHMSA's departure from the GPAC recommendation, the default values contained in § 192.712(e)(2)(D), in combination with a more conservative repair criterion, have the effect of adding multiple layers of conservatism without providing any supporting evidence or analysis, without explaining the risk to be addressed, or identifying a commensurate safety benefit. Furthermore, the Associations believe that, when considered in its totality, the excessive conservatism discourages innovation and advancement of technology.

The Associations request reconsideration of the Charpy v-notch default toughness values established in § 192.712(e)(2)(D) for segments with a history of reportable incidents caused by cracking or crack-like defects.

Finally, § 192.714(b), requires that during repairs, an operator must reduce the operating pressure to less than the predicted failure pressure determined in accordance with § 192.712. The multiple layers of conservatism discussed above in some instances could result in pressure

[119] *Id*. § 192.712(d)(1).
[120] *See* Section IV.B above.

reductions well below a safe operating limit. The Associations request that the provision be modified to use language provided for temporary pressure reductions in § 192.714(e)(i):

> A pipeline segment's operating pressure must be reduced during the repair process to a level not exceeding 80 percent of the operating pressure at the time condition was discovered or a level not exceeding the predicted failure pressure as calculated using § 192.712.[121]

This would a margin of safety comparable to pressure reductions for other repairs and is consistent with language in § 192.714(e)(i).

I. The Associations request reconsideration of § 192.319(f) to clarify that the deadline for an operator to repair severe coating damage is six months after having performed an assessment or within six months after receiving any necessary permits.

Section 192.319(d) requires that,

> [P]romptly after a ditch for an onshore steel transmission line is backfilled (if the construction project involves 1,000 feet or more of continuous backfill length along the pipeline), but not later than 6 months after placing the pipeline in service, the operator must perform an assessment to assess any coating damage and ensure integrity of the pipeline coating.[122]

Section 192.319(f), in turn, requires that an operator repair any severe coating damage "within 6 months after the pipeline is placed in service, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after receipt of the permits."[123]

The Associations request reconsideration of § 192.319(f) because it will require that an operator repair severe coating damage within six months after placing the pipeline into service. Such a compressed compliance timeframe does not provide an operator adequate time to both perform the coating assessment and then perform repairs. As currently drafted, § 192.319(d) and § 192.319(f) describe actions that are to be performed consecutively but then requires the second action to be taken within the same compliance deadline as the first. INGAA believes that this is a drafting error in the regulation and requests that PHMSA revise § 192.319(f) to permit an operator to complete any coating repairs within six months of having performed the assessment or within six months after receiving any necessary permits.

The Associations' request is consistent with § 192.461(f) and § 192.461(h) which address assessments that are performed after repairing or replacing an onshore steel pipeline that resulted in 1000 or more feet of backfill length along the pipeline. Section 192.461(f) requires that, within six months after the backfill, an operator must perform an assessment to assess any coating damage and ensure integrity of the coating. Within six months of completing any

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[121] 87 Fed. Reg. at 52,273.
[122] *Id.* at 52,268-69 (to be codified at § 192.319(d)).
[123] *Id.* at 52,268-69 (to be codified at § 192.319(f)).

assessment that identifies a deficiency, the operator must develop a remedial action plan and apply for permits needed to perform the repair. The operator must repair any severe coating damage within six months of performing the assessment, or as soon as practicable after obtaining necessary permits, but within six months of receiving the permits.

In addition, the Associations' request is consistent with PHMSA's statements at the June 6, 2017 GPAC meeting where PHMSA stated its intent for both § 192.319 and § 192.461 to "link" "the assessment timeframe to six months after the pipeline is placed in service, . . . plus an additional six months to complete the repairs"[124]

J. The Associations request that PHMSA grant reconsideration of 192.917(b) with respect to the meaning of "pertinent" and the requirement to collect data that has minimal, if any impact on safety.

The Final Rule amends existing § 192.917(b) to require that an operator gather and evaluate the data listed in § 192.917(b)(1). The regulation requires that the evaluation "analyze both the covered segment and similar non-covered segments, and it must (1) Integrate pertinent information about pipeline attributes to ensure safe operation and pipeline integrity, including information derived from" required operations and maintenance activities.[125] The regulation requires that an operator "begin to integrate all pertinent data elements specified in this section starting on May 24, 2023, with all available attributes integrated by February 26, 2024."[126]

The Associations request reconsideration with respect to the term "pertinent." Not all data will be pertinent for all pipelines in managing threats and risk. In addition, there can be other data that provide comparable information, and in some cases, eliminate a threat. For example, discharge temperature is relevant to coating and ultimately external corrosion, but when an operator can demonstrate temperatures will not adversely affect the coating, temperature data on downstream segments are unnecessary. The Associations request that operators be permitted to define the term when managing threats on their systems because the pertinence of data will vary from pipeline to pipeline based on a number of factors affecting individual facilities.

K. The Associations request reconsideration of § 192.714 to allow for a critical strain analysis of monitored dents.

New section 192.714 establishes repair criteria for onshore transmission pipelines that are not subject to integrity management regulations.[127] Section 192.714(d)(3) describes conditions that operators must record and monitor, but are not required to schedule for remediation. Among the monitored conditions is "A dent that is located between the 4 o'clock and 8 o'clock positions (bottom $^1/_3$ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12)."[128]

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[124] Transcript of GPAC Meeting at p. 39 (March 6, 2017) (Statement of Mr. Nanney).
[125] Final Rule, 87 Fed. Reg. at 52,273 (to be codified at § 192.917(b)).
[126] *Id.*
[127] *Id.* at 52,271.
[128] *Id.* at 52,272 (to be codified at § 192.714(d)(3)(i)).

PHMSA's amended integrity management regulations contain monitored conditions that are similar, if not the same, as those listed in § 192.714(d). In particular, § 192.933(d)(3)(i) identifies the following as a monitored condition:

> A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS12), located between the 4 o'clock and 8 o'clock positions (bottom $^1/_3$ of the pipe), and *for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded*.[129]

These monitored conditions are the nearly the same, except that § 192.714(d)(3)(i) does not contain the italicized language providing that an engineering analysis demonstrates that critical strain levels are not exceeded.

The Associations request that PHMSA reconsider § 192.714(d)(3)(i) to correct the inconsistency and to add the following language, which mirrors § 192.933(d)(e)(i): and *for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded*. There is no basis for allowing a critical strain analysis for this condition if found on a pipeline subject to integrity management regulations, but not allow the analysis for a pipeline not subject to integrity management.

L. The Associations request reconsideration of § 192.929(b)(3) to clarify the number of examination digs are required when performing direct assessment for stress corrosion cracking.

Section 192.929 sets forth the requirements applicable to an operator's plan for conducting direct assessment for the threat of stress corrosion cracking (SCC). The NPRM proposed to substantially revise this provision, including the addition of § 192.929(b)(3) addressing direct assessments. Proposed § 192.929(b) stated, "(3) *Direct examination.* In addition to the requirements and recommendations of NACE SP0204-2008, the plan's procedures for direct examination must provide for conducting a minimum of three direct examinations within the SCC segment at locations determined to be the most likely for SCC to occur."[130]

The Associations supported this provision and it was not addressed during the GPAC meetings.

The Final Rule, however, modified the language of § 192.929. Instead of requiring an operator to conduct "a minimum of three direct examinations within the SCC segment," the Final Rule requires that an operator conduct "a minimum of three direct examinations for SCC within the covered pipeline segment."[131]

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[129] *Id.* at 52,278 (to be codified at § 192.933(d)(3)(i)) (emphasis added).
[130] 81 Fed. Reg. at 20,722, at 20,845.
[131] Final Rule 84 at 52,276/

This modification is potentially significant. In a valve section, an operator may have three covered segments that the operator considers to be one SCC segment. The NPRM would have required that an operator perform three excavations in that SCC segment. By changing "SCC segment" to "covered pipeline segment, however, the Final Rule could be interpreted to require that an operator perform three excavations in each covered segment, *i.e.* nine excavations in the SCC segment.

The modification to the Final Rule language was not subject to notice and comment as required under the APA[132] and was not discussed by the GPAC. Nor are the costs of this provision reflected in PHMSA's Regulatory Impact Analysis, which concludes that the incremental costs related to integrity management are zero, as required under the Pipeline Safety Act.[133] The Associations request that PHMSA amend the Final Rule to re-instate the language as proposed in the NPRM.

In addition, the Associations request that PHMSA reconsider § 192.929(b)(2) which states:

> (2) *Indirect inspection*. In addition to NACE SP0204, the plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using the complementary measurement tools most appropriate for the pipeline segment based on an evaluation of integrated data.

The Associations request that PHMSA grant reconsideration of this language that so that it better aligns with the requirements of NACE SP0204-2008. Specifically, the Associations request that PHMSA clarify that an operator may use indirect inspection, or other types of measurements, such as ILI, that appear to be precluded under the existing text requiring two above-ground surveys. An ILI, which is permitted under NACE SP0204-2008, can provide comparable data and PHMSA should permit an ILI to replace one of the two above ground surveys.

M. Clarifications and Technical Corrections

The Associations request that PHMSA make the following clarifications and technical corrections to the Final Rule. The Associations may identify additional issues that may require clarification.

1. The Associations request that § 192.714 be revised to include a reference to section 7 of ASME/ANSI B31.8S-2004.

Section 192.714(d)(1), which addresses immediate repair conditions for non-HCA pipelines, does not contain the reference to section 7 of ASME B31.8S-2004 that is contained in the corresponding integrity management provision, § 192.933(d)(1). This is important because section 7 of ASME/ANSI B31.8S-2004, which is incorporated by reference into the regulations, contains important requirements that apply to the remediation of immediate repair conditions,

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132 *Owner-Operator Indep. Drivers Ass'n*, 656 F.3d at 588.
133 49 U.S.C. § 60102(b)(2).

including a provision allowing an operator five days following the determination of the existence of the condition in which to perform an examination. This is especially important because pipelines located outside of HCAs are subject to § 192.710 which addresses assessments outside of HCAs.

The Associations request that PHMSA add the following language to § 192.714(d)(1): "An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S-2004, section 7 in providing for immediate repair conditions."

2. The Associations request that PHMSA amend the definition of "wrinkle bend" to correct the formula.

The Final Rule adopted a definition for "wrinkle bend," adopting the definition as proposed in the NPRM. The Associations have determined that the formula reflected in the regulations is missing content and requests that the definition be revised to correct the listed equations.

3. The Associations request that PHMSA clarify reference to "uprate" in 192.714(d)(2)(v) and 192.933(d)(2)(c).

Sections 192.714(d)(2) and § 192.933(d)(2) describe several conditions as two-year conditions and one-year conditions, respectively. Several of the descriptions contains the following phrase: "the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611."[134]

Section 192.611 does not govern uprating a pipeline. The Associations request that PHMSA amend these sections to make clear that a class location, not MAOP, was uprated in accordance with § 192.611.

4. The Associations request clarification of the definition of "Systemic" and "Non-systemic" in § 192.465(f).

Under § 192.465(f), if any annual test station reading indicates cathodic protection levels below required levels, the operator must determine the extent of the area that is inadequately protected. Under § 192.465(f)(1), an operator "must investigate and mitigate any non-systemic or location-specific causes."[135] If the cause of cathodic protection levels is systemic, the operator must perform close interval surveys in both directions from the test station that is producing the low reading. An operator must remediate areas with insufficient cathodic protection and confirm that adequate cathodic protection has been restored. If the cause is non-systemic, such as a blown fuse in a cathodic protection rectifier, when the fuse is replaced and the rectifier settings confirmed, the work is complete. The operator need not conduct close interval surveys in both directions from the rectifier.

[134] Final Rule, 87 Fed. Reg. at 52,272, 52,278.
[135] *Id*. at 52,269.

The Associations request that PHMSA provide regulatory compliance guidance with respect with respect to meaning of the terms "systemic" and "non-systemic," as these terms are not discussed in the Final Rule.

5. The Associations request that PHMSA clarify that "100amps/m^2" should be "100 amps/m^2 AC" in § 192.473(c)(3).

Section 192.473(c)(3) requires that an operator whose pipeline is subject to stray currents must have a continuing monitoring plan to minimize the detrimental effects of such currents.[136] The final rule specifies the requirements of such programs. Section 192.473(c)(3) requires the development of a remedial action plan to correct instances where interference current, among other things, is greater than or equal to 100 amps per meter squared (100 amps/m^2).

The Associations believe that the reference to "100 amps/m^2" is a typographical error and requests that PHMSA amend the regulation so that it states "100 amps/m^2 AC."

6. The Associations request that PHMSA clarify the meaning of growth prior to the next scheduled assessment in § 192.933(d)(3).

In the NPRM, PHMSA proposed § 192.933(d)(1)(vi) to include as an immediate repair condition "[a]ny indication of significant stress corrosion cracking (SCC)."[137] In its comments on the NPRM, INGAA requested that PHMSA delete this provision and instead reference the 1.1xMAOP failure pressure ratio for determining whether crack anomalies are an immediate repair condition. During the GPAC meeting, PHMSA proposed the following cracking repair criteria for HCA (1-year condition) and non-HCA (2-year condition) pipe: "The crack anomaly is determined to have (or will have prior to the next assessment) a predicted failure pressure (PFP that is less than 1.39 times MAOP (for Class 1) or 1.50 time MAOP (for Classes 2, 3and 4)."[138] Following discussion, the GPAC recommended several modifications to the proposed language, including removal of the "or will have prior to the next assessment" language.[139]

In the Final Rule, PHMSA removed this language from what became § 192.33(d)(2)iv), but added the following language to § 192.933(d)(3) addressing "monitored conditions."

> Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:[140]

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136 49 C.F.R. § 192.473.
137 81 Fed. Reg. at 20,846.
138 GPAC Meeting Slides at 188 (March 26-28, 2018).
139 GPAC Meeting Final Voting Slides at 22 (March 26-28, 2018).
140 Final Rule, 87 Fed. Reg. at 52,278.

The Associations request that PHMSA clarify what actions are required if an anomaly is expected to “grow to dimensions” or “have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment.”

V. Conclusion

As set forth herein, the Associations request that PHMSA grant the petition for reconsideration of several provisions of the Final Rule.

Respectfully submitted,

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