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DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 192 and 195

[Docket No. PHMSA-2025-0019]

RIN 2137-AF44

Pipeline Safety: Repair Criteria for Hazardous Liquid and Gas Transmission Pipelines

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

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: PHMSA proposes to modernize and to clarify the anomaly response criteria in the Federal pipeline safety regulations for gas transmission and hazardous liquid pipelines. Driven by twenty years of technological development, modern engineering concepts allow operators to identify, schedule, and remediate pipeline anomalies more effectively and in a less costly manner. PHMSA proposes incorporating these improved safety practices into its regulations by finalizing certain safety improvements advanced in recent rulemakings for gas transmission pipelines and extending those changes to hazardous liquid pipelines. In addition, PHMSA proposes certain non-substantive revisions to its gas and hazardous liquid repair regulations to improve compliance.

DATES: Submit comments by **[INSERT 60 DAYS FROM PUBLICATION]**.

A public meeting of PHMSA's statutory advisory committees will be held on a date to be announced in the *Federal Register*.

ADDRESSES: Submit comments by any of the following methods, identifying docket number PHMSA-2025-0019 at the top of the first page:

- On <https://www.regulations.gov>, follow instructions to “submit a comment.”
- By mail or hand delivery to Docket Management System, U.S. Department of Transportation, 1200 New Jersey Avenue S.E., West Building Ground Floor, Room W12-140, Washington, D.C. 20590-0001. Hand delivery is available to this address between 9:00 a.m. and 5:00 p.m., Monday through Friday (except Federal holidays). Include two copies if submitting by mail and include a self-addressed and stamped postcard to receive confirmation of receipt.
- By fax to Docket Management System at (202) 493-2251.

Comments may be viewed at <https://www.regulations.gov/docket/PHMSA-2025-0019>.

Comments are posted without changes or edits, including any personal information provided.

DOT’s privacy statement can be reviewed at <https://www.dot.gov/privacy>. As required by the Administrative Procedure Act (5 U.S.C. § 553(b)(4)), a plain language summary of the proposed rule is also available in section I.B, and this proposal will be available online on the rulemaking docket.

Confidential Business Information (CBI): You may designate a comment as CBI if your comment contains commercial or financial information that is customarily treated as private and that you actually treat as private by sending to Sayler Palabrica, at the contact information listed below, the following: (1) the original document with each page containing CBI marked as “confidential;” (2) a redacted copy with the CBI deleted; and (3) an explanation of why the information you are submitting is CBI. *See* 49 CFR 190.343. Any comment not specifically designated as CBI will be placed in the public docket.

FOR FURTHER INFORMATION CONTACT: Sayler Palabrica, Standards and Rulemaking Division, by phone at (202) 744-0825 or by e-mail at sayler.palabrica@dot.gov.

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I. Executive Summary

A. Background

In the early 2000s, PHMSA created integrity management (IM) programs for gas transmission and hazardous liquid pipelines. Both IM programs included criteria for responding to anomalies.¹ These requirements—which today apply approximately to 41 percent of hazardous liquid and less than 18 percent of gas mileage in high consequence areas (HCAs) and other higher risk locations—used generic depth measurements that did not account for the specific anomaly or the operating parameters of the pipeline.² That approach has forced costly

¹ *Pipeline Safety: Pipeline Integrity Management in High Consequence Areas*, 68 FR 69778 (Dec. 15, 2003); *Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Repair Criteria)*, 67 FR 1650 (Jan. 14, 2002).

² Though a smaller portion of gas transmission pipelines are in an HCA than hazardous liquid pipelines, the gas response schedule also applies to Class 3, Class 4, and other moderate consequence areas with a high operating stress level. 49 CFR 192.710(a). The IM program for hazardous liquid pipelines applies to pipelines in, or that could affect, an HCA. § 195.452(a).

repair of pipelines in good serviceable condition, interrupting service for consumers and disrupting other proactive operational activities.

Technology has dramatically advanced in the quarter of a century since the adoption of the IM program. In-line inspection (ILI) tools can now detect more pipeline anomalies with a higher degree of certainty, even interacting threats and previously unreliably detected threats.³ Models can depict an entire pipeline with the impact of the anomaly and calculate the critical strain. All of this can be used to determine a pipeline’s predicted failure pressure or fatigue life.

In 2022, PHMSA amended its gas pipeline response criteria to incorporate some of these modern, engineering-based concepts.⁴ In this proceeding, PHMSA proposes to complete that work and to extend the same concepts to hazardous liquid pipelines.

B. Summary of Proposal

Element	Proposal
Response schedule – gas	The anomaly response tiers in 49 CFR § 192.714(d) are denoted as immediate, near-term, and other conditions. Near-term is one year under IM and two years otherwise. The duplicative schedule at § 192.933 is removed to allow one central location for the gas response schedule.
Response schedule – hazardous liquid	The same three anomaly response tiers apply for hazardous liquid IM pipelines. Near-term response is one-year. The hazardous liquid response schedule is placed in its own section at § 195.453 as part of the IM program.
Response criteria – gas	Editorial revisions are proposed to improve the clarity of the § 192.714 response requirements. Criteria use a failure pressure ratio (FPR) rather than spelling out ‘predicted failure pressure times the maximum allowable operating pressure.’ Substantively, for gas response: (1) a modern engineering-based criterion is added for the immediate response of cracks at an FPR of 1.1 and below; (2) the immediate crack depth criterion is revised to 70 percent or more; (3) immediate response to preferential seam corrosion is revised to an FPR of 1.1 and below; and (4) the dent interacting threat immediate criterion adds an exception for non-mechanical metal loss under 10 percent.

³ Rosen USA (Rosen), Comment, Docket ID PHMSA-2017-0151-0025, at 1 (Sept. 28, 2018); *see supra* section II.B.

⁴ *Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments*, 87 FR 52224 (Aug. 24, 2022) (2022 Safety of Gas Transmission Rule).

Element	Proposal
Response criteria – hazardous liquid	<p>Modern engineering-based metrics are added alongside the existing depth-based measurements for hazardous liquid response criteria. A consistent FPR of 1.1 and below is used for the immediate response of metal loss and cracks, with near-term response required at FPRs of 1.39 and below. On depth measurements, immediate response is added at 70 percent depth for cracks, with near-term response of cracks at 50 percent depth and higher. For dents, immediate response is required for interacting threats from mechanical damage (mechanical corrosion, cracking, gouging, and a stress riser) at any orientation, near-term response is required for all dents that were previously listed as 180-day conditions, while the seam corrosion provision is targeted to preferential metal loss. A dent ECA can be used to calculate an alternative timeline for all dent criteria. Finally, hazardous liquid pipelines not subject to IM should respond following API RP 1160.</p>
Anomaly evaluation	<p>Update § 192.712 and create a similar provision at § 195.415:</p> <ul style="list-style-type: none"> (a) Anomaly evaluation must be conducted by a subject matter expert and include uncertainties, like tool tolerance. (b) Metal loss analysis can use API 579 and Psqr, in addition to ASME B31G, R-STRENG, and other models demonstrated to provide comparable results. (c) A dent ECA is proposed with a reassessment safety factor of two for gas pipelines and five for hazardous liquid pipelines. (d) Crack analysis may use technically accepted fracture mechanic methods, including API 579 Level II or III, Modified Ln-Sec, and Raju-Newman equations. The <i>in-situ</i> crack exam provision is relocated to this paragraph. (e) Toughness can be derived by Charpy v-notch or other valid testing methods. The default toughness values are updated and the methods to obtain toughness and other material properties for the analysis are extended to part 195, including adding § 195.407 to allow collection of material property records.
Discovery	<p>A consistent anomaly discovery definition continues to apply from an operator having adequate information within an 180-day period. Expedited response to immediate conditions is required from preliminary ILI results, with discovery otherwise following the final ILI results.</p>
Temporary pressure reduction	<p>Two consistent options for temporary pressure reductions taken until gas and hazardous liquid pipelines are permanently repaired: a 20 percent reduction or reduction to a pressure below the predicted failure pressure times a design factor.</p>
General repair requirements	<p>The disperse general repair requirements are editorially revised and centralized at §§ 192.711 and 195.422 to encourage compliance.</p>

C. Cost-Benefit Summary

PHMSA estimates that the proposed rule would generate substantial cost savings of approximately \$390 million each year. Gas transmission pipeline operators are expected to experience between \$214.6 and \$241.7 million in cost savings each year, with hazardous liquid and carbon dioxide pipeline operators expected to experience cost savings of approximately \$148.5 million in cost savings each year (both at a three percent discount rate). By accelerating responses to critical threats while eliminating unnecessary excavations, the proposal is also expected to enhance pipeline safety, to benefit worker safety, to minimize detrimental environmental impacts, to alleviate economic costs associated with congestion caused by work-zones from excavations, and to improve regulatory certainty and clarity for operators. The Preliminary Regulatory Impact Analysis (PRIA) provided in the rulemaking docket includes additional information regarding the costs, cost-savings, and benefits of the proposed rule.

II. Background

A. Regulatory Origin

As originally adopted, the Federal Pipeline Safety Regulations generally required gas⁵ and hazardous liquid⁶ pipeline operators to repair safety impediments within a reasonable time.⁷ In the early 2000s, PHMSA established more detailed anomaly response schedules in adopting

⁵ “Gas” pipeline is used throughout this document to refer to pipelines regulated under part 192, which can be natural gas and any “flammable gas, or gas which is toxic or corrosive.” 49 CFR 192.3 (definition of “gas”).

⁶ “Hazardous liquid” pipeline is used throughout this document to refer to pipelines regulated under part 195, which includes hazardous liquid and carbon dioxide pipelines. § 195.2 (definition of “pipeline”). In addition to carbon dioxide, “hazardous liquid” includes “petroleum, petroleum products, anhydrous ammonia, and ethanol or other non-petroleum fuel, including biofuel, which is flammable, toxic, or would be harmful to the environment if released in significant quantities.” § 195.2 (definition of “hazardous liquid”).

⁷ *Establishment of Minimum Standards*, 35 FR 13248, 13274 (Aug. 19, 1970) (codifying §§ 192.711 and 192.713); *Transportation of Liquids by Pipeline—Requirements for the Design, Construction, Operation, and Maintenance*, 34 FR 15473, 38369 (Oct. 4, 1969); *Transportation of Liquids by Pipeline*, 46 FR 38357, 38369 (July 27, 1981) (recodifying § 195.401 and the part 195 regulations to reflect the enactment of the Hazardous Liquid Pipeline Safety Act of 1979 (Pub. L. No. 96-129)).

the IM program requirements for hazardous liquid and gas transmission pipelines.⁸ The IM rules required operators to assess the integrity of higher-risk pipelines in HCAs at certain intervals, *i.e.*, at least once every five years for hazardous liquid and at least once every seven years for gas transmission pipelines. The IM rules also included response criteria in §§ 192.933 and 195.452(h) that applied to anomalies detected during these assessments. This led to specific response requirements for anomalies discovered in HCAs compared with longstanding generic requirements to make repairs as needed.

The original response criteria in the IM rules reflected the limited assessment technology and evaluation methods available at the time. Relying on traditional measurements, the criteria defined anomalies by location (*e.g.*, top- vs. bottom-side dents) or depth (*e.g.*, a crack at 50 percent depth). The response times for these criteria largely were not based on the anomaly's remaining safe life.⁹ Though ILI tools could reliably measure the maximum depth of certain anomaly types, tool technologies and analytical methods were not sufficiently mature to produce high-resolution anomaly profiles reliably, to detect and classify interacting threats (such as selective seam weld corrosion and dents with interacting features), or to predict the remaining life of cracks and dents.

By looking solely at measured anomaly size, the first IM response criteria overlooked the interaction between an anomaly and the specific characteristics of the pipeline (*e.g.*, size, material, and operating conditions), both of which must be considered to understand the likely impact on integrity and serviceability. As a result, the response margins in the original IM rules

⁸ *Pipeline Safety: Pipeline Integrity Management in High Consequence Areas*, 68 FR 69778 (Dec. 15, 2003); *Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Repair Criteria)*, 67 FR 1650 (Jan. 14, 2002). See also *Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipeline)*, 65 FR 75378 (Dec. 1, 2000) (promulgating rest of hazardous liquid IM).

⁹ Consistent with the technology of the time, remaining strength calculation criteria were limited to metal loss.

required remediation of anomalies in advance of what would otherwise be necessary to maintain pipeline integrity in many cases.

B. Technological Development

Pipeline technology has improved dramatically since the adoption of the anomaly response criteria in the original IM rules. Modern ILI tools can detect a wider range of defects with greater accuracy, particularly when compared to the technology available in the early 2000s. Today, commercially available ILI tools can detect pipe body crack sizing with 90 percent certainty to one millimeter via an Electromagnetic Acoustic Transducer (EMAT) tool,¹⁰ and axial Magnetic Flux Leakage (MFL-A) tools can size corrosion depth with 80 percent certainty to 0.1 times the wall thickness.¹¹ Much of this technological improvement can be attributed to an increase in the number of sensors on modern ILI tools, which has improved both accuracy and probability of detection.¹² For example, sensors on crack ILI tools have increased from 480 in 2000 to over 1000 on today's tools, while MFL ILI corrosion tools have increased from 240 sensors in 2000 to about 1250 today. This corresponds to an improvement from +/- 10 percent wall thickness depth accuracy and 80 percent probability of detection in tools used in 2000 to +/- 0.03 inch and 90 percent probability of detection in tools used today.¹³ Further, with dents, ILI

¹⁰ Lacking precision when introduced in the mid-2000s, EMAT tools can now reliably detect smaller cracks with greater accuracy due to innovation in tool sizing and sensor count. Kinder Morgan, *Technical Justification for Use of EMAT as an Alternative Technology for Integrity Assessment of SCC in HCAs*, Docket ID PHMSA-2011-0023-0773 at 7–9 (Aug. 2019) (describing operator's development of EMAT ILI assessment and continued advancement of the technology over the 2010s). Previously, cracking was indicated by ILI run and not sized. Jeff Aron et al., *Development of an EMAT In-Line Inspection System For Detection, Discrimination, and Grading of Stress Corrosion Cracking in Pipelines* (Feb. 2005), <https://www.netl.doe.gov/sites/default/files/2018-03/FG013105.PDF> (“Cracks of 30 [percent] or greater of the wall thickness in depth were imaged. Their depths and lengths could be estimated from the data.”).

¹¹ See, e.g., Rosen, *RoCorr MFL-A Service: In-line Ultra-High-Resolution Metal Loss Detection and Sizing* (2024), <https://contenthub.rosen-group.com/api/public/content/729e05931aca4953ac0a47dbdf2c6566?v=f9378e13>; Rosen, *RoCD EMAT-C Service: In-line High-Resolution Detection and Sizing of Axial Cracks* (2024), <https://contenthub.rosen-group.com/api/public/content/7e9f40578f924917a4403fa7fc5ba41e?v=0071d845>.

¹² Colonial Pipeline Co. (Colonial), Comment, Docket ID PHMSA-2025-0019-0013, at 7 (July 21, 2025).

¹³ Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 7.

tools now can detect a dent as small as 0.2 percent of wall thickness on large diameter pipelines.¹⁴ Together, these advances have increased the probability of detection, probability of identification, and accuracy of sizing of pipeline anomalies.

The experience gained by deploying ILI to more pipelines has led to further advancements in the detection and modelling of increasingly complex defect types.¹⁵ New ILI tools are being designed and developed to assess anomalies with increasing accuracy and to address threats that could not previously be detected on a reliable basis. For example, to address hard to detect defects on double submerged arc welded pipe, Colonial Pipeline and NDT Global collaborated to create a multi-diameter and multi-threat tool that can be adjusted in the field for the size and threat to the pipeline.¹⁶ Preferential metal loss, once thought not capable of reliable detection by ILI,¹⁷ can now be assessed using a tool train that combines MFL-C corrosion and EMAT crack tools. Inertial Mapping Units have been updated to sub-meter accuracy with speed

¹⁴ See Rosen, *In-line Inspection Services for Deformation, Geometry and Mapping*, available at: <https://www.rosen-group.com/en/expertise/product-and-service-finder/in-line-inspection-services-for-deformation-geometry-and-mapping#ro-geo-xt-service> (noting how sensors improve accuracy and data quality, with more accurate tools “[m]inimiz[ing] conservatism of integrity assessments based on exceptionally detailed anomaly profiles”).

¹⁵ Rosen, Comment, Docket ID PHMSA-2017-0151-0025, at 1 (Sept. 28, 2018); The Williams Companies, Inc., Comment, Docket ID PHMSA-2024-0005-0421, at 3, 5 (Aug. 27, 2024) (noting how study and application “drives the vendors to constantly improve and refine their tools,” and today “[o]perators...who regularly deploy [ILI] technology across its enterprise of pipeline systems[] can assess risk with a level of detail and certainty that was not available 10 years ago” with “the data provided by the current generation of [ILI] tools giv[ing] [an operator] certainty and clarity around the risk assessment decisions...regarding potential threats”).

¹⁶ Nathan Leslie *et al.*, *Compact 36” Ultrasonic ILI Tool for Enhanced Pipeline Integrity Management*, NDT Global, available at: <https://www.ndt-global.com/resources/white-paper/compact-36-ultrasonic-ili-tool-for-enhanced-pipeline-integrity-management/>.

¹⁷ See, e.g., Michael Baker Jr., Inc, Kiefner & Assoc., TTO No. 5, *Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation*, at 6, 47, 60 (Apr. 2004), available at: <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-transmission-integrity-management/65266/tto05lowfrequencyerwfinalreportrev3april2004.pdf> (finding ILI tools in 2004 unreliable to identify longitudinal seam anomalies).

control, offering accurate measurement of bending strain caused by geohazards or construction activity through comparison to past tool runs.¹⁸

As ILI tools and modeling have advanced, critical strain levels and predicted failure pressure have become the preeminent, technically based option for evaluating anomalies to ensure pipeline safety. Until the 1970s, operators relied on burst tests, manufacture specifications, and Barlow’s formula to predict potential failures. From the 1980s through the 2000s, operators began to use metal loss analysis to assess corrosion, starting with B31G and then Effective Area Method computer software like Remaining Strength (RSTRENG), which allows for more accurate representation to calculate predicted failure pressure.¹⁹ Analytical methods have continued to advance over time, becoming more precise and expanding to other types of anomalies, such as cracking and dents, allowing operators to engage in increasingly complex analysis and assessment of a pipeline’s fitness for service.

Today, with enhanced accuracy and data quality, computational algorithms can provide fracture mechanics, critical strain analysis, and remaining strength calculations to better predict when a defect might fail. API 579 contains three different levels of engineering calculations and analysis for each anomaly type, scalable based on the amount of data available.²⁰ Models are

¹⁸ Rosen, *RoGeo XYZ Service: In-line High-Resolution Pipeline Route Mapping, Curvature Measurement and Strain Assessment*, available at: <https://contenthub.rosen-group.com/api/public/content/cc5d8df35a384c0a95e69d30122e31f8?v=9790a90c>.

¹⁹ Am. Soc. of Mech. Eng’rs (ASME), Supplement to ASME B31 Code for Pressure Piping, ASME B31G-1991, *Manual for Determining the Remaining Strength of Corroded Pipelines* (1991) (first edition as its own standard); Kiefner & Assocs. Inc., *Validity of Standard Defect Assessment Methods for the Alliance Pipeline Operating at 80% of SMYS*, at 3–4 (Sept. 6, 2018), available at: <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-transmission-integrity-management/65316/validityofcorrosionassessmentsr1.pdf> (noting ASME B31G was first introduced as a supplement to B31.8 in 1984).

²⁰ American Petroleum Institute (API) & ASME, API 579-1/ASME FFS-1, *Fitness-for-Service* (4th ed., Dec. 2021) (“API 579”); see INGAA Integrity Management Continuous Improvement Group, *Definition and Application of Fitness for Service to Gas Pipelines* (May 31, 2012), available at: <https://ingaa.org/wp-content/uploads/2013/04/20024.pdf>.

capable of overlaying multiple data inputs from different threats to provide a clearer understanding of the pipeline and potential anomalies.²¹ Innovations in data processing and machine learning enable real-time algorithmic analysis of tool results, better interpreting complex signals and deformation shapes, and expediting decision-making.²²

Use of 3D modelling of ILI data, including through the use of models like Plausible Profiles (Psqr), has allowed for “a data driven and more accurate probabilistic representation of corrosion features in pipelines that was not operationally feasible before the data revolution.”²³ Fracture mechanics analysis provides an avenue to consider all variables in the predicted failure of a crack or crack-like anomaly by quantifying the relationship between material properties, stresses, and crack propagation. This demonstrates that the propensity for crack failures is not based on depth alone, and depth-based crack response metrics must be overly conservative as a result.²⁴ Dent analysis has also undergone significant recent study and advancement. Contrary to historical practice and understanding, the latest research has shown that “dent depth alone is not a great predictor of the effect a dent can have on the fatigue life of a pipeline.”²⁵ API developed and released RP 1183 in 2020 to provide guidance using engineering critical assessment (ECA)

²¹ E.g., Creaform, *Pipeline Integrity Assessment Software for NFT Pipeline Inspection*, available at: <https://www.creaform3d.com/en/products/software/creaform-integrity-suite/pipeline> (discussing use of 3D analysis to show full coverage of pipeline surfaces and damages, feeding assessment calculation models).

²² See NDT Global, *Evolving from a Leading ILI Company to a Preferred Provider of Integrity Management Solutions*, available at: <https://www.ndt-global.com/resources/news/evolving-from-a-leading-ili-company-to-a-preferred-provider-of-integrity/> (“We are leveraging machine learning and artificial intelligence techniques and use our big data platforms to improve the accuracy and reliability of the results from our inspection tools continuously. This is the key to delivering the greatest value in integrity assessments to enable proactive pipeline integrity management.”); Rosen, Comment, Docket ID PHMSA-2011-0151-0025, at 1; T.D. Williamson, Comment, Docket ID PHMSA-2017-0151-0024, at 2.

²³ TC Energy, *TC Energy wins Global Pipeline Award* (Nov. 17, 2021), available at: <https://www.tcenergy.com/stories/2021/2021-11-17-tc-energy-wins-global-pipeline-award/>.

²⁴ See Vlad Semiga, BMT Fleet Technology, *Fatigue Considerations for Natural Gas Transmission Pipelines*, at 10 (June 30, 2016), available at: <https://ingaa.org/wp-content/uploads/2016/07/29846.pdf> (noting how the geometry factor is built into the equation, providing growth rate constraints that include material properties).

²⁵ Semiga, *Fatigue Considerations for Natural Gas Transmission Pipelines*, at 65.

to evaluate a dent's fitness for service.²⁶ Finite element analysis, which would not be possible without the more precise data derived from advanced ILI tools, provides the ability to simulate full-scale testing with numerical modeling.²⁷

C. Modernization in PHMSA Regulations

PHMSA has modernized its regulations in recent years to account for many of these technological advancements. In 2019, for example, PHMSA revised its assessment requirements for gas transmission pipelines to apply to certain non-HCA locations and made similar revisions to its assessment requirements for hazardous liquid pipelines.²⁸ In 2022, PHMSA revised its anomaly response and evaluation requirements for gas transmission pipelines, adding detailed scheduling requirements at §§ 192.714 and 192.933 that incorporate predicted failure pressure- and strain-based criteria “to assure that anomalies are repaired before they become an immediate condition and are at or near failure.”²⁹ PHMSA also added analysis calculation criteria to § 192.712.³⁰ As explained below, PHMSA proposes to apply these concepts to the response and evaluation criteria for hazardous liquid pipelines.

²⁶ API, Recommended Practice (RP) 1183, *Assessment and Management of Pipeline Dents* (1st Ed. Nov. 2020).

²⁷ “Due to the complexity and variability of dent shapes, dimensions, and the potential for coincident features, full-scale testing and numerical modeling (FEA) have been the two essential tools that have been deployed by the industry to assess the fundamental behavior of dents.” Aaron Dinovitzer et al., PR214-203804-R01, *Systematize 20 Years of Mechanical Damage Research*, sec. 3.4.2.6 (May 31, 2022), available at: https://primis.phmsa.dot.gov/rd/FileGet/17097/Systematize_20_Years_of_Mechanical_Damage_Research_V2.pdf.

²⁸ *Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments*, 84 FR 52180 (Oct. 1, 2019) (2019 Safety of Gas Transmission Rule); *Pipeline Safety: Safety of Hazardous Liquid Pipelines*, 84 FR 52260 (Oct. 1, 2019).

²⁹ *2022 Safety of Gas Transmission Rule*, 87 FR at 52245. These modern criteria were added alongside the traditional depth-based measurements for operators who so prefer.

³⁰ Section 192.712(c) was remanded without vacatur by the court in *INGAA v. PHMSA*, 114 F.4d 744 (D.C. Cir. 2024) for PHMSA to reconsider the dent ECA process. Order on Pet. for Panel Reh'g, *INGAA v. PHMSA*, 114 F.4th 744 (D.C. Cir. Dec. 10, 2024) (No. 23-1173). Section 192.712(b) and (d) for corrosion and cracks were created in the 2019 Safety of Gas Transmission Rule.

III. Advanced Notice of Proposed Rulemaking

In a May 2025 advanced notice of proposed rulemaking (ANPRM), PHMSA solicited public feedback on improving anomaly response requirements for gas and hazardous liquid pipelines.³¹ Public response overwhelmingly favored modernizing these requirements to incorporate a performance-based, engineering-focused approach—one that prioritizes anomalies based on calculated predicted failure pressure, strain, and remaining life rather than one dimensional thresholds. Comments submitted by the Liquid Associations—API, the Liquid Energy Pipeline Association (LEPA), GPA Midstream Association, and the American Fuel & Petrochemical Manufacturers—note that the existing hazardous liquid anomaly response requirements are obsolete and fail to leverage over twenty years of advancement in ILI technology and data analytics.³² Comments by the Gas Associations—the Interstate Natural Gas Association of America (INGAA), American Gas Association (AGA), and GPA Midstream Association—supported using modern anomaly evaluation, as did individual gas and hazardous liquid pipeline operators.³³ Representatives of smaller operators requested that in any modernization effort PHMSA retain the existing depth-based options, stating that engineering-based analyses can be costly and resource-intensive up-front, before reaping substantial cost-savings.³⁴ The Pipeline Safety Trust (PST) supported improving the clarity of response requirements but cautioned against reducing the safety level for gas transmission IM regulations or making deregulatory changes without considering safety benefits, environmental impact, and

³¹ *Pipeline Safety: Repair Criteria for Hazardous Liquid and Gas Transmission Pipelines*, 90 FR 21715 (adv. notice May 21, 2025).

³² Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 2–4 (July 21, 2025).

³³ Gas Associations, Comment, Docket ID PHMSA-2025-0019-0017, at 4–5 (July 21, 2025).

³⁴ Air Liquide Large Indus. US, L.P., Comment, Docket ID PHMSA-2025-0019-0012, at 3 (July 21, 2025); Compressed Gas Ass’n, Comment, Docket ID PHMSA-2025-0019-0009, at 5 (July 18, 2025).

public participation.³⁵ The National Association of Pipeline Safety Representatives (NAPSR) similarly cautioned not to reduce the standard of care in IM regulations, which NAPSR credited with the declining rate of incidents and accidents.³⁶

The Liquid Associations and operators like Colonial Pipeline Co. (Colonial) and Marathon Pipe Line (Marathon) commented that incorporating improved evaluation methods for hazardous liquid pipelines would enable the consolidation of near-term response timelines.³⁷ Hazardous liquid operators also requested that PHMSA allow an ECA to respond to dents based on a detailed calculation of strain and fatigue life.³⁸ Commenters suggested certain changes to the criteria and evaluation methods adopted in a recent rulemaking for gas transmission lines to provide greater flexibility and to reflect modern technologies and practices, though PST cited the need to maintain the safety margins established in these new regulations.³⁹

As engineering-based criteria depend on an evaluation of the anomaly, commenters suggested revisions to anomaly evaluation methods for gas transmission and that these revisions be adopted for hazardous liquid pipelines. Suggestions included explicitly approving additional metal loss and crack evaluation methods;⁴⁰ revising default toughness values based on recent

³⁵ PST, Comment, Docket ID PHMSA-2025-0019-0016, at 2 (July 21, 2025).

³⁶ NAPSR, Comment, Docket ID PHMSA-2025-0019-0025, at 4 (Aug. 1, 2025).

³⁷ Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 2, 7; Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 49–50; Marathon, Comment, Docket ID PHMSA-2025-0019-0018, at 4–5 (July 21, 2025).

³⁸ *See, e.g.*, Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 5; Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 3; Enterprise Prods. Operating LLC (Enterprise), Comment, Docket ID PHMSA-2025-0019-0015 at 4 (July 21, 2025).

³⁹ Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 7; PST, Comment, Docket ID PHMSA-2025-0019-0016, at 2.

⁴⁰ Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 20; Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 19.

research;⁴¹ and allowing a process in part 195 to determine material properties by extending the procedures in § 192.607.⁴²

IV. Discussion of the Proposal

To address concerns with the use of inconsistent or imprecise terminology in the existing regulations, PHMSA proposes to use the terms “anomaly” and “response criteria” throughout the regulations.⁴³ The use of these terms is consistent with ASME B31.8S and other industry sources. An anomaly is an unexamined deviation from the norm in pipeline material, coatings, or welds, which includes defects and imperfections identified upon further examination.⁴⁴ Sections 192.714 and 195.453 list “response criteria” that require response in a set time for an anomaly that meets those levels, though PHMSA has previously used the term “repair criteria” interchangeably.⁴⁵ Response refers to the action an operator takes on an identified anomaly, including remediation, to ensure safety such as a repair or temporary pressure reduction.⁴⁶ Response is completed by permanent repair, which means replacing the pipe cylinder containing the defect, removing the anomaly, or taking other actions permanently to restore pipeline serviceability.

⁴¹ Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 10; TC Energy, Comment, Docket ID PHMSA-2025-0019-0019, at 5 (July 21, 2025).

⁴² Energy Transfer LP, Comment, Docket ID PHMSA-2025-0019-0020, at 18 (July 21, 2025).

⁴³ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0017, at 4–5 (noting that current requirements usage of interchangeable terminology is confusing); PST, Comment, Docket ID PHMSA 2025-0019-0016, at 1. As each are consistent terms, PHMSA does not propose defining these terms in §§ 192.3 and 195.2.

⁴⁴ See ASME, Code for Pressure Piping Supplement to ASME B31.8, B31.8S-2018, *Managing System Integrity of Gas Pipelines*, sec. 13 (2018).

⁴⁵ See PST, Comment, Docket ID PHMSA 2025-0019-0016, at 1.

⁴⁶ See ASME, B31.8S-18, sec. 7.

A. Response Schedules

Existing requirement: Anomaly response schedules set timelines to respond to criteria based on severity. The gas response criteria are broken out by immediate, scheduled (one-year in HCAs, two-years otherwise), monitored, and “other” conditions. A schedule is repeated at § 192.933(d) for HCAs and § 192.714(d) outside of HCAs. Existing hazardous liquid response criteria at § 195.452(h) are designated as immediate, 60-day, 180-day, and “other” conditions.

Proposal: PHMSA proposes three anomaly response categories to be used consistently between gas and hazardous liquid pipelines: (1) immediate, (2) near-term, and (3) other conditions. The time for immediate response is unchanged. PHMSA proposes to consolidate the repetitive response schedule at § 192.933 into § 192.714 to eliminate unnecessary duplication.

Discussion: PHMSA proposes three clear and consistent anomaly response categories for parts 192 and 195: immediate, near-term, and other conditions. The deadline for responding to near-term conditions is one year in HCAs, two years otherwise. The proposed framework allows for necessary deviations based on location and commodity. It also better prioritizes remediation timelines for hazardous liquid pipelines and provides editorial clarity for gas transmission pipelines. Establishing clear benchmarks promotes public safety and compliance. The proposed revisions to the gas transmission response schedule are purely editorial and the response timelines remain unchanged. Additional information about the proposals is provided below.

PHMSA proposes to create three response categories for gas transmission and hazardous liquid pipelines. The first category, immediate response conditions, would continue to apply to anomalies that require remediation immediately upon discovery. The second category, near-term conditions, would replace the existing provisions in part 192 for one-year conditions (§ 192.933(d)) and two-year conditions (§ 192.714(d)) and in part 195 for 60-day and 180-day

conditions (§ 195.452(h)). The third category, other conditions, would apply to anomalies scheduled for response prior to the next reassessment or for monitoring during the next scheduled reassessment.

Consolidating the response category for near-term conditions will eliminate unnecessary complexity and improve the efficiency of PHMSA’s regulations. Currently, the regulations in part 192 and part 195 recognize four different types of comparable conditions that require a response within either 60 days, 180 days, one year, or two years. This four-tiered framework introduces unnecessary inconsistency and complexity into the regulations without producing a meaningful safety benefit. Consistent with the approach used in industry standards, PHMSA proposes to group these conditions into a single near-term category denoted as “near-term” conditions, a term which provides consistency and avoids confusion inherent in the term “scheduled conditions.”⁴⁷

For near-term conditions on gas transmission lines, PHMSA proposes to require response within one year of discovery for segments in higher risk locations (*i.e.*, HCAs) or two years of discovery for segments in lower risk locations. PHMSA proposes to create an analogous near-term category for hazardous liquid pipelines and to require a response within one year of discovery for all covered segments. PHMSA notes that industry commenters expressed strong support for consolidating the response timelines for hazardous liquid pipelines, which they characterized as unnecessarily complex.⁴⁸ PHMSA further notes that two decades of experience applying IM and progress in assessment tools indicate that operators can schedule repairs safely

⁴⁷ API, RP 1160, *Managing System Integrity for Hazardous Liquid Pipelines*, sec. 9.2.3.4 (3rd ed. 2019, reaff’d Mar. 2024) (also denoting this category as “near-term”).

⁴⁸ Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 11, 49–50; Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 2; Marathon, Comment, Docket ID PHMSA-2025-0019-0018, at 4–5 (recommending consolidating the two into a single 180-day criteria).

on a one-year basis for many anomalies.⁴⁹ A one-year response deadline strikes an appropriate balance between the need to remediate anomalies before they grow to critical dimensions, aligning with industry standards like API RP 1160 and API RP 1176,⁵⁰ and allowing operators to engage in the coordination and planning required to complete that remediation without causing unnecessary adverse impacts to customers, communities, and the environment.⁵¹ As discussed in more detail in section IV.B.ii below, PHMSA proposes to address the risk of fatigue-related, time-dependent threats on hazardous liquid pipelines by prioritizing specific response criteria for certain immediate or near-term conditions.⁵² For example, as Colonial notes, PHMSA’s proposal to respond immediately to metal loss at or below a 1.1 FPR captures slightly more metal loss, while allowing operators to manage the remainder safely under the new near-term response category.⁵³ Adopting more stringent immediate repair criteria for metal loss, cracking, and dents, but longer timelines and engineering-based criteria for less injurious anomalies, allocates resources more efficiently on high-risk threats.

The third response category for other conditions applies to anomalies that can be scheduled safely for response prior to the next reassessment or that can be monitored for change during that reassessment. Currently, gas regulations contain two similar requirements at § 192.714(d)(3) and (f) designated as “monitored” and “other” conditions. Splitting these requirements has caused confusion and inconsistency. PHMSA proposes to retain the substantive

⁴⁹ Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 2 (noting that updating “response timelines for ‘near term’ conditions is possible without impacting safety because the advances in understanding anomaly growth and failure mechanisms that have occurred since the 2001 [IM] rule allow for better prediction of pipeline failures.”).

⁵⁰ API RP 1160 (recommending 270-day response of near-term conditions in “critical locations” (*i.e.*, HCAs)); API, RP 1176, *Recommended Practice for Assessment and Management of Cracking in Pipelines*, sec. 11.7.3 (1st ed. July 16, 2021, reaff’d Mar. 2024, incl. Errata 1 (Feb. 2021)) (specifying 365-day response for certain cracks).

⁵¹ See Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 11, 49–50.

⁵² See *Pipeline Safety: Pipeline Integrity Management in High Consequence Areas*, 68 FR 69778 (Dec. 15, 2003).

⁵³ Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 8.

requirement in a single category termed “other” conditions to be applied to both gas and hazardous liquid pipelines, located at paragraph (d)(3). This revision would require that other conditions in (d)(3) must be addressed as required by ASME B31.8S Figure 7.2.2.1, the dent reassessment interval established under the ECA, or monitored no later than the next scheduled reassessment. As PHMSA recently explained in another rulemaking proceeding, Figure 7.2.2.1 provides a sliding scale to determine response timelines based on specified minimum yield strength (SMYS) and predicted failure pressure.⁵⁴ “Other” conditions under part 195 accounts for some operational differences by directing operators to evaluate any condition not listed for immediate or near-term response that could impair pipeline integrity and schedule remediation as appropriate. API RP 1160 Section 9.2.3.6—a recognized industry practice operators must follow under § 195.452(b)—describes conditions that operators should record and monitor during the next integrity assessment, including stable manufacturing and construction conditions (provided operating conditions have not changed since the last pressure test) or conditions that do not impair pipeline integrity.⁵⁵ In both gas transmission and hazardous liquid response, monitoring at the next regular reassessment is the floor, even if the dent ECA, ASME B31.8S, or API RP 1160 imply a longer period. This is consistent with current requirements.

Finally, PHMSA proposes to create a single, consolidated response schedule for gas transmission pipelines at § 192.714. The intent of the proposed revision is to eliminate the duplicative requirements that are currently codified at § 192.714 (for non-HCA segments) and § 192.933 (for HCA segments) without affecting the applicable response deadlines. In other words, a one-year response deadline would continue to apply to near-term conditions on HCA

⁵⁴ See *2022 Safety of Gas Transmission Rule*, 87 FR at 52252 (discussion when Figure 7.2.2.1 was named Figure 4 in ASME B31.8S-2004).

⁵⁵ API RP 1160, sec. 9.2.3.6 & fig. 6. An anomaly with a scheduled response under API RP 1160 sec. 9.2.3.6 that extends beyond the date of the next reassessment is essentially an “other” condition.

segments, and a two-year response deadline would continue to apply to near-term conditions on non-HCA segments under the consolidated schedule. This revision would maintain current levels of safety as the proposed requirements are equivalent to the current response criteria. When the proposed response schedule in § 192.714 applies to covered segments in HCAs, the rigorous subpart O requirements would still apply.

B. Response Criteria

PHMSA proposes a modern, engineering-analysis-based anomaly response schedule. The modern criteria will go alongside traditional measures, accommodating smaller operators as requested.⁵⁶ PHMSA largely implemented these criteria for gas transmission lines in a 2022 final rule and proposes to complete that work and modernize the anomaly response schedule for hazardous liquid pipelines, too. The proposed rule uses calculations, including predicted failure pressure and fatigue life, to determine the proper schedule for responding to anomalies. Using these advanced analyses, operators can better “characterize the risks associated with specific” anomalies, tailor safety responses “to the characteristics and operating conditions of specific pipelines,” and make “more informed decisions about what needs to be repaired and when,” avoiding costly response to non-threats.⁵⁷

Predicted failure pressure (PFP) describes the calculated maximum pressure a pipeline can withstand before a specific anomaly fails. PFP can be calculated using a remaining strength equation for metal loss or a fracture mechanics model for cracks.⁵⁸ Pipeline operation is based on the maximum pressure—maximum allowable operating pressure (MAOP) for gas or maximum

⁵⁶ Air Liquide Large Indus., Comment, Docket ID PHMSA-2025-0019-0012 at 3; Compressed Gas Ass’n, Comment, Docket ID PHMSA-2025-0019-0009 at 5.

⁵⁷ Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 7.

⁵⁸ Modern dents are evaluated based on strain and fatigue, as discussed in section IV.C.i.

operating pressure (MOP) for hazardous liquids—that is safe for operation. Response is designed to ensure predicted failure pressure cannot fall below the maximum safe operating pressure using the failure pressure ratio (FPR). FPR is calculated as the PFP divided by the MAOP or MOP of the pipeline.⁵⁹ The result of that calculation determines how quickly an operator must repair the anomaly under PHMSA’s response criteria. Risk and time-sensitivity increase as the ratio lowers approaching 1.0.

At an FPR of 1.0, the pipeline is predicted to fail at any moment when operated at or above the MAOP or MOP (though the MAOP and MOP have built-in safety factors). An additional margin is necessary to respond before predicted failure pressure reaches MAOP or MOP (*i.e.*, FPR is 1.0) for several reasons. That margin accounts for any potential error between the operating pressure and point of failure and for any permissible temporary pressure surges.⁶⁰ It also accounts for further degradation that may occur depending on how soon an anomaly is detected after reaching the point of failure, given the variation that occurs in detecting anomalies within the reassessment cycle.⁶¹

Immediate response criteria are generally set at a 1.1 FPR. At this point, the anomaly’s burst pressure is within 10 percent of the maximum operating pressure, requiring immediate attention. Near-term response criteria are generally derived from the design factors in §§ 192.611 and 195.406, which results in a 1.39 FPR for Class 1 gas transmission pipelines and most hazardous liquid pipelines. To show the importance of these safety margins, consider a pipeline

⁵⁹ API 579 refers to this as “remaining strength factor,” defined as “ratio of the collapse pressure of a damaged component to the collapse pressure of the undamaged component.” API 579, sec. 1A.87.

⁶⁰ *See, e.g.*, §§ 192.201(a)(2) (minimum performance standards for pressure relieving and limiting stations pegged to 110 percent of MAOP or 75 percent of SMYS, whichever is lower), 192.739(b) (inspection and test requirements for pressure limiting and regulating stations pegged to 104 percent of MAOP), and 195.406 (allowing a pipeline to operate at up to 110 percent of MOP during surges and other variations from normal operations).

⁶¹ The reassessment interval is up to five years in hazardous liquid HCAs, seven years in gas transmission HCAs, and 10 years on other gas transmission pipelines requiring assessment.

with a MAOP of 1,000 psig where an operator calculates a PFP of 1,390 psig for a metal loss anomaly. With a 10 percent range for tool inaccuracy, the actual burst pressure could range from 1,251 psig to 1,529 psig. Because corrosion is a time-dependent threat, the PFP will continue to decrease, which means that remediation must be scheduled before the next inspection cycle to prevent failure. This example is representative of other near-term response criteria. If an anomaly does not meet an immediate response condition but meets one of these criteria, it is operating below its intended safety margin, necessitating a scheduled response.

For gas transmission pipelines under part 192, PHMSA created a modern, engineering-based response schedule in § 192.714 in the 2022 Safety of Gas Transmission Rule. An engineering-based response schedule is supported by anomaly evaluation calculations, which PHMSA promulgated for gas transmission pipelines in § 192.712 through the 2019 and 2022 Safety of Gas Transmission Rules. In this rulemaking, PHMSA proposes completing the modern response schedule for gas and creating one to improve public safety and efficiency on hazardous liquid pipelines.

i. Gas Transmission Response Criteria

Existing requirement: After the 2022 Safety of Gas Transmission Rule, § 192.714(d) contains an engineering-based and traditional measurement-based schedule for responding to almost every anomaly; however, there is no engineering-based immediate response criterion for cracks. Currently, immediate response is required for cracks at 50 percent wall thickness, § 192.714(d)(1)(v); preferential seam corrosion with an FPR below 1.25 in seams formed by direct current (DC) electric resistance welding (ERW), low-frequency (LF) ERW, electric flash welding (EFW), or with a longitudinal joint factor less than 1.0, § 192.714(d)(1)(iv); top-side

dents with metal loss, cracking, or a stress riser, § 192.714(d)(1)(ii); and metal loss with an FPR of 1.1 and below or greater than 80 percent wall thickness, § 192.714(d)(1)(i)&(iii).⁶²

Proposal: PHMSA proposes (1) to add an immediate response criterion for cracks with an FPR of 1.1 and below, (2) to raise the immediate crack depth threshold to 70 percent wall thickness, (3) to revise the immediate response of preferential seam corrosion to an FPR of 1.1 and below, and (4) to refine the interacting dent immediate response criterion to include gouging, but to exclude non-mechanical metal loss up to 10 percent depth, focusing the criterion on excavation damage. PHMSA proposes no change to metal loss criteria.

Discussion: To complete the gas engineering-based response schedule, PHMSA proposes slight amendments in the criteria to reflect improvements in tool technology and capability.

Crack criteria. First, PHMSA proposes adding an immediate response criterion for cracks (or crack-like anomalies) at 1.1 FPR.⁶³ This provides a PFP-based immediate and near-term response criterion for each crack and metal loss anomaly on gas systems where there is currently not one for immediate crack response. PHMSA sought to adopt a similar PFP-based immediate criterion for cracks in the 2022 Safety of Gas Transmission Rule, but that provision was vacated on judicial review in *INGAA v. PHMSA*, 114 F.4th 744 (D.C. Cir. 2024). The U.S. Court of Appeals for the District of Columbia Circuit found that PHMSA had not performed a reasoned cost-benefit analysis for the measure it selected in that final rule—immediate response of cracks with an FPR less than or equal to 1.25.⁶⁴ *INGAA* asserted throughout that rulemaking and

⁶² The same criteria exist as the same provisions within § 192.933(d).

⁶³ The crack criteria capture stress corrosion cracking and other cracking or crack-like anomalies.

⁶⁴ See *INGAA v. PHMSA*, 115 F.4th at 752.

ensuing litigation that a 1.1 FPR level was sufficient.⁶⁵ INGAA continues to do so, citing API RP 1176, which recommends immediate response of likely cracks with an FPR less than 1.1, with a predicted depth greater than 70 percent of nominal wall thickness, or where maximum depth exceeds the tool's sizing capabilities.⁶⁶

PHMSA finds that a 1.1 FPR level is appropriate for immediate response when using advanced engineering calculations. In formulating this proposal, PHMSA reviewed pipeline safety consensus standards, recommendations, and research; received nearly a decade of public comment on the topic; and benefited from extensive advice from the Gas Pipeline Advisory Committee (GPAC) in public fora. Increased ILI data accuracy, paired with using traceable, verified, and complete records, gives PHMSA confidence setting a 1.1 FPR level for immediate crack response. In the past, PHMSA was concerned that tool tolerances could swallow a 1.1 FPR safety factor, leading the Agency to offer a 1.25 FPR with tool tolerance built in.⁶⁷ However, for all other anomalies, operators must add tool tolerance to the FPR. This approach incentivizes operators to deploy more precise tools.⁶⁸ Proposed § 192.712(a) addresses this concern by requiring that a qualified subject matter expert perform the analysis, providing additional

⁶⁵ Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 8; AGA, API, APGA, & INGAA, *Comments on Pipeline Safety: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, And Other Related Amendments Final Rule*, Docket ID PHMSA-2011-0023-0451 at 4–5, 42–43 (June 6, 2018); API & INGAA, *Petition for Reconsideration of Gas Transmission Final Rule (RIN 2)*, Docket ID PHMSA-2011-0023-0641 at 7–10 (Sept. 23, 2022).

⁶⁶ API RP 1176, sec. 11.7.2; Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 8.

⁶⁷ See *2022 Safety of Gas Transmission Rule*, 87 FR at 52248; GPAC, *All GT Voting Slides*, Docket ID PHMSA-2011-0023-0656 at 49 (GPAC vote of Mar. 28, 2018) (vote recommending that for crack anomalies PHMSA “consider 1.1 x MAOP for immediate conditions after tool tolerance has been field verified and applied”). See also INGAA & API, *Petition for Reconsideration*, Docket ID PHMSA-2011-0023-0644 at 10 (Sept. 23, 2022) (requesting that PHMSA “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”).

⁶⁸ See *GPAC Transcript March 28, 2018*, Docket ID PHMSA-2016-0136-0040 at 72–73 (2018) (Andy Drake) (noting that too high of an immediate response level would discourage proactive safety behavior and result in “a gamesmanship thing going on where people don’t look at tool tolerance, they don’t look at colony length, they’re not doing the things you want them to do so that they don’t have to dig up half of the earth”).

assurance that the analyses will be performed correctly to include tool tolerance and other uncertainties.

An FPR of 1.1 “is an appropriate level if [an operator is] doing this correctly with tool tolerances, colony length considerations, and” other considerations accounted for, and “[t]hat’s actually better engineering.”⁶⁹ The technical advisors on the GPAC previously recommended that PHMSA “consider 1.1” as the immediate crack level.⁷⁰ API RP 1176 for assessing cracks recommends this immediate response level, too.⁷¹ EMAT tools for cracks have advanced significantly through additional deployment and improvement in recent years, increasing the reliability of ILI-based assessment and reducing concerns expressed about over-conservatism.⁷² Cracks with slightly higher FPRs (e.g., 1.25) will fall under the existing near-term response condition, providing sufficient margin for operators to respond before an integrity threat arises.

Second, PHMSA proposes complementary depth-based immediate response criterion for cracks at depths greater than 70 percent of pipe wall thickness. The existing 50 percent crack depth threshold does not reflect current technical understandings and should align with established industry standards and recent research.⁷³ API RP 1176 treats cracks deeper than 70 percent of nominal wall as immediate conditions, while those between 50 and 70 percent require

⁶⁹ *GPAC Transcript March 28, 2018*, Docket ID PHMSA-2016-0136-0040 at 73 (2018) (Andy Drake).

⁷⁰ Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 8 (recommending that an FPR of 1.1 “was a sufficient and a technically supported standard” for the immediate response to cracks); GPAC, *All GT Voting Slides*, Docket ID PHMSA-2011-0023-0656 at 49. Liquid Associations and operators made similar arguments in the hazardous liquid context, as discussed there.

⁷¹ API RP 1176, sec. 11.7.2. Though the FPR and depth criteria are consistent with those in API RP 1176, PHMSA does not propose to incorporate that standard by reference for these purposes. Specifically, the likelihood factors for cracking and time-dependence in 11.6.3 and 11.6.4 are highly subjective as written.

⁷² See Rosen, *RoCD EMAT-C Service: In-line High-Resolution Detection and Sizing of Axial Cracks* (2024), <https://contenthub.rosen-group.com/api/public/content/7e9f40578f924917a4403fa7fc5ba41e?v=0071d845> (EMAT tool detecting pipe body crack sizing with 90 percent certainty to one millimeter); Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 7 (noting that they observed crack tools with 480 sensors in 2000, which has increased to 1028 on today’s tool).

⁷³ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 6.

a 365-day response.⁷⁴ The study *Fatigue Considerations for Natural Gas Transmission Pipelines* found that some cracks between 50 and 70 percent depth could remain in a typical gas transmission pipeline for at least 100 years before failing.⁷⁵ This shows that operators can manage cracks safely with modifications to operating characteristics depending on the crack properties. Requiring more cracks to be treated as immediate response conditions than is necessary results in unnecessary costs and leads to “adverse environmental, landowner, and pipeline operational impacts that outweigh the resulting safety benefit.”⁷⁶

PHMSA proposes to shift the 50 percent crack depth level to a near-term condition. This ensures that 50 percent through-wall cracks receive near-term response in one to two years. Immediate response at 70 percent, with near-term response above 50 percent, strikes the proper balance for safety by ensuring that operators address more imminent threats while retaining a degree of planning for near-term cracks.

ERW immediate criterion. Third, PHMSA proposes revising from an FPR of 1.25 to an FPR of 1.1 the immediate response criterion for metal loss preferentially affecting a detected longitudinal seam weld formed by DC-ERW, LF-ERW, EFW, or with a joint factor less than 1.0.⁷⁷ This criterion addresses selective seam weld corrosion, which can behave like a crack defect. PHMSA proposes to revise the FPR criterion to align with those adopted for cracks. Because these seam types are particularly susceptible to selective seam weld corrosion, several existing provisions address the assessments for pipe with these seams. Section 192.712(d)

⁷⁴ API RP 1176; *see* Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 7 (noting that API RP 1176 supports a near-term response for cracks between 50 and 70 percent wall thickness).

⁷⁵ Semiga, *Fatigue Considerations for Natural Gas Transmission Pipelines*, at 53 (“Operating at less severe cyclic severities (*i.e.*, lower SSIs) allows for deeper and longer flaws to exist in the pipeline while still meeting the 100-year fatigue life criterion.”); *see* Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 7.

⁷⁶ Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 5.

⁷⁷ *See* Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, attach. 2 at 8 (recommending this change).

specifies that analysis must be analyzed using a fracture mechanics model proven appropriate to the pipe and seam weld properties, while § 192.917(e)(4) in IM further requires assessments on these types of pipes use tools proven capable of assessing seam threats. The proposed clarifying of the requirement for a subject matter expert to perform any analysis under § 192.712 further strengthens the analysis and assures it considers all variables. Operators must also prioritize assessing pipe with these seams under § 192.917(e)(4) to ensure the prompt detection of potential anomalies, reducing the risk that an anomaly may have existed at threatened levels for some time.⁷⁸ The obligation to prioritize assessments using analysis models proven appropriate to the seam properties provide an adequate margin of safety for vintage seam types, making an additional safety factor in the response criterion unnecessary.

Dents. Fourth, PHMSA proposes to clarify the immediate response criterion in § 192.714(d)(1)(ii) for top-side dents that have interacting threats of metal loss, cracking, or a stress riser.⁷⁹ This criterion for top-side dents is intended to guard against excavation and unrestrained mechanical damage. Top-side dents are more likely to be caused by excavation damage and be unrestrained, while bottom-side dents are more likely to be caused by an object, like a rock, that remains in place and keeps the dent from shifting under fatigue.⁸⁰ But the existing criterion does not reflect this concern precisely as it also requires response to dents with interacting metal loss caused by ordinary corrosion, which is a less pressing threat.⁸¹ That is not

⁷⁸ In addition, § 192.917(e)(3) requires that an operator can only consider manufacturing defects (including seam defects) stable if an operator subjected them to a hydrostatic pressure test of at least 1.25 times the MAOP, with no subsequent reported incidents attributable to the defect.

⁷⁹ See § 192.933(d)(1)(ii).

⁸⁰ Unrestrained dents can be at higher risk from increased fatigue and strain because the dent size later can “re-round” and re-form upon fluctuations in pressure, and unrestrained dent shapes at pressure can be underpredicted. Arnav Rana et al., BMT Canada Ltd., *Improve Dent/Cracking Assessment Methods*, at 55 (PRCI May 30, 2022), https://primis.phmsa.dot.gov/rd/FileGet/17090/Improve_Dent_Cracking_Assessment_Methods.pdf.

⁸¹ Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 38 (noting that the existing criterion requires remediation of many dents with non-injurious metal loss).

the intended effect, as an accelerated response is justified for mechanical damage, not ordinary corrosion.

To focus the criterion on mechanical damage and other higher risk threats, PHMSA proposes to exclude corrosion-related metal loss that does not exceed 10 percent depth. PHMSA preliminarily finds that a 10 percent threshold is appropriate—though some operators recommended applying a 20 percent threshold—because of the variability in distinguishing between gouging and other mechanical damage from corrosion.⁸² A 10 percent threshold ensures that operators will not invest unnecessary resources in addressing dents with superficial corrosion, while minimizing the risks of misclassifying interacting gouges or mechanical damage.

Consistent with the focus on mechanical and excavation damage, PHMSA proposes to add gouging as a specified interacting threat.⁸³ “Gouging” is a mechanical form of metal loss (as opposed to corrosion) that removes metal mechanically.⁸⁴

General. Throughout § 192.714(d)(2), the near-term response FPRs are tied to the design factor and involve the class location of the pipeline where the anomaly is located. In the recently issued Class Location Change Final Rule, PHMSA provided an FPR for operators to use as part

⁸² See Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 16, 22–25 (citing Matt Romney et al., *The Power to Know More About Third Party Gouging*, (Pipeline Tech. Conf. 2022)). One report found that ILI vendors had an average gouge probability of detection of 0.81 and a probability of identification of 0.61. Sanjay Tikku et al., BMT Canada Ltd., PR-214-203805, *Performance Evaluation of ILI Systems for Dents and Coincident Features*, at 55 (PRCI Mar. 6, 2024), available at: [https://primis.phmsa.dot.gov/rd/FileGet/19308/693JK31910014POTA-Validate_In-Line_Inspection_\(ILI\)_Capabilities_to_Detect_Characterize_Mechanical_Damage-_FR.pdf](https://primis.phmsa.dot.gov/rd/FileGet/19308/693JK31910014POTA-Validate_In-Line_Inspection_(ILI)_Capabilities_to_Detect_Characterize_Mechanical_Damage-_FR.pdf).

⁸³ See Gery Wilkowski et al., Stress Eng’g Servs., Inc., PRCI L51705, *Cyclic Pressure Fatigue Life of Pipelines with Plain Dents, Dents with Gouges, and Dents with Welds*, (June 1, 1994) (concluding that “gouge depth has a significant impact on fatigue life. Underground gouges whose depth is more than 10[percent] of the wall cannot be counted on to have any fatigue life.”).

⁸⁴ Gouging in a dent is itself a stress riser and significantly raises the risk of cracking, these factors decrease the fatigue life of a dent with a gouge.

of the IM alternative for eligible Class 3 segments.⁸⁵ PHMSA added that FPR because PFP is based on the original design of the pipe, which varies for eligible Class 3 segments depending on the class location at the time of installation. To create a unified response schedule for all gas transmission lines, PHMSA proposes moving the FPR for eligible Class 3 segments from § 192.611(a)(4)(iii)(C) to § 192.714.

PHMSA also proposes certain editorial revisions to the gas response section. PHMSA has restructured the section to avoid duplication in revisions that are not intended to impart substantive changes. For example, PHMSA proposes centralizing FPR criteria and references to ECA provisions, rather than repeating the same FPR for each anomaly. These changes should provide additional clarity to the regulations and increase operator compliance.

ii. Hazardous Liquid Response Criteria

Section 195.452 contains a response schedule for hazardous liquid pipelines that has not been amended since the adoption of the IM regulations in the early 2000s. PHMSA proposes to create a more modern response schedule that combines engineering-based metrics with existing depth-based measurements. Though largely modeled on the response schedule for gas transmission lines, the proposal accounts for the unique characteristics of hazardous liquids where necessary.

PHMSA proposes locating the updated hazardous liquid response schedule in a new section, § 195.453, within the IM regulations. Proposed § 195.453 would incorporate many of the editorial revisions discussed above for gas transmission lines to provide consistency in the response schedule for hazardous liquid pipelines under the IM program. That consistency should

⁸⁵ Section 192.611(a)(4)(iii)(C); *Pipeline Safety: Class Location Change Requirements*, 91 FR 1608, 1640 (Jan. 14, 2026).

aid operators, regulators, and other interested stakeholders in evaluating, monitoring, and making decisions about pipeline repairs.⁸⁶

1. Cracks

Existing requirement: The IM regulations treat “[a] potential crack indication that when excavated is determined to be a crack” as a 180-day condition, § 195.452(h)(iii)(G).

Proposal: PHMSA proposes to treat cracks with an FPR of 1.1 and below or that are through more than 70 percent of the remaining wall thickness as immediate response conditions. PHMSA proposes to treat cracks with an FPR of 1.39 and below or with a depth above 50 percent as near-term response conditions.

Discussion: The response schedule in the existing IM regulations does not include any explicit criteria for cracks that require an immediate response. As the Liquid Associations note, “[i]n recent years, operators have deployed advanced ultrasonic crack detection tools to find cracks in the pipe body and longitudinal seam, created calculation methods for cracks, and learned which crack-like features warrant immediate repair.”⁸⁷ Drawing on that experience, PHMSA proposes to categorize cracks at levels of 1.1 FPR and 70 percent depth as immediate response conditions. These two criteria align with API RP 1176, a recommended practice on the *Assessment and Management of Cracking in Pipelines*, and industry comments submitted in response to the ANPRM.⁸⁸ Moreover, as Enterprise explains in its comments, EMAT tools have good sensitivity and resolution for identifying and sizing cracks up to 70 percent wall thickness.

⁸⁶ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 26–27.

⁸⁷ Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 10.

⁸⁸ API RP 1176, sec. 11.7.2 (recommending these levels as providing a “necessary safety margin to ensure” safe repair and also recommending immediate response of cracks predicted to interact with a dent, which are addressed by PHMSA in a dent criterion); see Enterprise, Comment, Docket ID PHMSA-2025-0019-0015 at 10–11 (encouraging adoption of 1.1 FPR and a 70 percent wall thickness immediate response conditions to provide necessary safety margin on cracks and align with API RP 1176).

Adding the proposed crack criteria to the list of immediate response conditions will capitalize on the latest EMAT technology and improve pipeline safety by providing a “necessary safety margin to ensure” safe repair.⁸⁹ Several other operators expressed support for including these crack thresholds in the immediate response category.⁹⁰

PHMSA proposes to use a 1.39 FPR level in the near-term response category for cracks. This threshold is consistent with the design factor in § 195.106 for most pipe and the approach used in the 2022 final rule for gas transmission lines. Though some hazardous liquid operators suggested that pipelines with an FPR of 1.25 or less are unlikely to fail within one year based on research published by the Pipeline Research Council International (PRCI), the commenters did not provide that research to PHMSA for review.⁹¹ API RP 1160 recommends near-term response within 270 days for anomalies with an FPR below 1.25, and the proposed 1.39 FPR level accounts for the additional quarter of a year provided for its near-term response.⁹² PHMSA recognizes that API RP 1176 recommends response within 365-days for cracks below a 1.25 FPR or exceeding 50 percent depth⁹³ and will consider further publicly submitted information on the appropriate FPR measure for near-term response of cracks and metal loss.

As a corollary depth measurement, PHMSA proposes near-term response for cracks at 50 percent or more of wall thickness.⁹⁴ The *Study on Reliability of In-ditch NDE for SCC Anomalies*

⁸⁹ Enterprise, Comment, Docket ID PHMSA-2025-0019-0015 at 10–11; *see* API RP 1176.

⁹⁰ *See* Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 49 (noting these measures match operator data and evidence outlined in API TR 1190); Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 22; Marathon, Comment, Docket ID PHMSA-2025-0019-0018, at 5 (recommending incorporating API RP 1176 by reference). Though consistent with criteria in API RP 1176, PHMSA does not propose to incorporate that standard by reference for these purposes as the likelihood factors for cracking and time-dependence are subjective.

⁹¹ Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 20.

⁹² API RP 1160, sec. 9.2.3.4.

⁹³ API RP 1176, sec. 11.7.3.

⁹⁴ *See* API RP 1176, sec. 11.7.3.

illustrates declining *in situ* examination accuracy when depth exceeds 50 percent, supporting the need for near-term response.⁹⁵

2. Metal Loss

Existing requirements: The IM regulations for hazardous liquid pipelines require immediate response for metal loss greater than 80 percent of nominal wall thickness, § 195.452(h)(4)(i)(A), or where the remaining strength shows the predicted burst pressure is less than the MOP (*i.e.*, FPR below 1.0), § 195.452(h)(4)(i)(B). In addition, the IM regulations prescribe an 180-day deadline for responding to the following metal loss conditions, § 195.452(h)(4)(iii):

- a calculation of the remaining strength of the pipe shows operating pressure is less than the established maximum operating pressure at the anomaly location,
- predicted metal loss greater than 50 percent wall thickness in an area of general corrosion,
- predicted metal loss greater than 50 percent wall thickness at a pipeline crossing, or in areas of widespread circumferential corrosion or that could affect a girth weld,
- any indication of corrosion of or along a longitudinal seam weld, and
- a gouge or groove greater than 12.5 percent of the nominal wall.

Proposal: PHMSA proposes to make metal loss with an FPR of 1.1 and below an immediate response condition, while retaining the 80 percent depth criterion. For near-term response, PHMSA proposes to include general metal loss with an FPR of 1.39 and below, to limit the 50 percent depth criterion to localized pitting, and to focus the longitudinal seam criterion on preferential metal loss. PHMSA proposes no change to the gouge or groove criterion.

Discussion: PHMSA proposes to include corrosion at 1.1 FPR and below as an immediate response condition. The current threshold at MOP is outdated and introduces unnecessary risk, particularly for time-dependent anomalies like metal loss, by deferring response until the

⁹⁵ Jason Van Velsor & Scott Riccardella, Structural Integrity Assocs., Inc., PR-335-143705-R01, *Study on Reliability of In-ditch NDE for SCC Anomalies*, at 35 (PRCI June 11, 2018); *see* API RP 1176, sec. 11.7.3.

remaining strength of the pipeline coincides with the highest allowable operating pressure.

PHMSA adopted the MOP threshold before the use of engineering analysis in determining anomaly response became standard practice. Modern, strain-based response criteria incorporate a safety factor, both to ensure that an operator responds before PFP reaches MOP and to account for temporary surges above MOP that are permitted under § 195.406. Adding a safety factor is particularly appropriate given the longer time being permitted for near-term response to metal loss anomalies at less critical dimensions, as Colonial notes, and the cost-savings and other benefits from the longer near-term response timeline outweighs the addition of a slightly more immediate response.⁹⁶

A 1.1 FPR is reasonable for immediate response to metal loss on hazardous liquid pipelines. API RP 1160 treats metal loss with an FPR below 1.1 as requiring immediate response,⁹⁷ and at least one operator, Colonial, applies the same immediate response threshold for metal loss on its hazardous liquid system.⁹⁸ Gas regulations also require immediate response to metal loss at a 1.1 FPR, and there is no technical reason for hazardous liquid response requirements to be less protective.

Next, PHMSA proposes to retain the immediate response requirement for metal loss greater than 80 percent of nominal wall thickness. No comments from the May 2025 ANPRM recommended changing that criterion, and the reliability of inspection tools and remaining life models diminishes at such high levels of wall loss. The 80 percent threshold is consistent with industry standards, such as API RP 1160 and ASME B31G-2023, which cautions that “due

⁹⁶ Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 8.

⁹⁷ API RP 1160, sec. 9.2.3.3. This excludes tool tolerance, which PHMSA will require.

⁹⁸ Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 8 (noting that there is conservatism built-in to the remaining strength models but it would require “aggressive” defect growth rates “identified through multiple ILI run results comparisons and other data integration”).

consideration shall be given to the accuracy of measurements and effective corrosion rates when the depth of metal loss exceeds 80 percent of the actual pipe wall dimension.”⁹⁹

PHMSA proposes three changes in the near-term response category. First, PHMSA proposes a general 1.39 FPR threshold for metal loss, consistent with the level for cracks and for reasons explained in section IV.B.ii.1 above. The 1.39 FPR threshold is appropriate considering the additional time afforded to respond compared with the existing 180-day criterion, though PHMSA welcomes comments with technical study or data on the appropriateness of near-term response at 1.25 FPR.

Second, PHMSA proposes narrowing the general 50 percent criterion to apply only to localized pitting. The 1.39 FPR criterion addresses the failure risk for most metal loss anomalies. But, as Marathon notes, aggressive pitting with complex corrosion can cause pinhole leaks that pass an FPR criterion.¹⁰⁰ The proposal addresses that threat by focusing the existing 50 percent wall thickness criterion on localized corrosion pitting.

Third, PHMSA proposes to limit the near-term response criteria to corrosion that preferentially affects a susceptible longitudinal seam, including the heat-affected zone. This proposal aligns with the gas transmission response criteria. It received broad support in the comments submitted in response to the ANPRM, with commenters noting that the existing criterion is overly broad by requiring remediation of any corrosion that coincides with a

⁹⁹ API, RP 1160 sec. 9.2.3.3; ASME, Supplement to ASME B31 Code for Pressure Piping, B31G-2023, *Manual for Determining the Remaining Strength of Corroded Pipelines*, at 1, 19 (2023). *See also* ASME, Supplement to ASME B31 Code for Pressure Piping, B31G-1991, *Manual for Determining the Remaining Strength of Corroded Pipelines*, Fig. 1-2 (1991) (requiring repair above 80 percent depth).

¹⁰⁰ Marathon, Comment, Docket ID PHMSA-2025-0019-0018, at 4 (recommending retaining the existing 50 percent depth criterion as it applies to localized pitting).

longitudinal seam.¹⁰¹ Preferential seam weld corrosion is different than ordinary corrosion coinciding with a seam, and modern ILI tools are capable of recognizing that distinction.¹⁰² By focusing on preferential longitudinal seam weld corrosion, the proposed amendment will avoid unnecessary excavations and response to superficial indications of corrosion that operators know are non-injurious.¹⁰³ Indeed, Energy Transfer estimates that it repairs two to three hundred non-critical seams annually due to this overbreadth.¹⁰⁴ PHMSA’s proposal allows operators to treat coincidental seam weld corrosion the same as any other metal loss anomaly, ensuring safety while avoiding unnecessary excavation. PHMSA notes that the proposal does not include an FPR threshold and requires near-term response for all anomalies preferentially affecting longitudinal seams. The absence of an FPR threshold, which is included in the comparable provision for gas transmission lines, is necessary to account for the accelerated fatigue rates that are generally experienced on hazardous liquid pipelines.

PHMSA is not proposing any change to the 12.5 percent gouge or groove criteria. Though the Liquid Associations omitted the term “groove” from their recommended regulatory text, they provided no reasoning to support that change in approach.¹⁰⁵

¹⁰¹ API & LEPA, Comment, Docket ID DOT-OST-0025-0026-0874 at 10 (May 5, 2025) (recommending to focusing the criteria on seams known to be potentially injurious, consistent with the gas requirement); Energy Transfer, Comment, Docket ID PHMSA-2025-0019-0020, at 8 (July 21, 2025) (recommending adopting the seam criterion similar to gas); Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 9–10 (similar, though suggested a selective seam weld corrosion criterion separate from general PFP criterion, as on gas).

¹⁰² Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 8 (noting that new ILI tools are better able to find these seam defects).

¹⁰³ See API & LEPA, economic comment, Docket ID PHMSA-2025-0019-0027, at table 1 (Dec. 3, 2025) (supplemental comments representing nearly half of industry estimated quantified cost savings and suggesting substantial cost savings by focusing this requirement on injurious seams); GPA Midstream Ass’n, Comment, Docket ID PHMSA-2025-0019-0029 (Dec. 8, 2025) (supporting API & LEPA economic comment).

¹⁰⁴ Energy Transfer, Comment, Docket ID PHMSA-2025-0019-0020, at 8.

¹⁰⁵ Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 17.

3. Dents

Existing requirement: Immediate response is required under the IM regulations for top-side dents (a) with any indication of metal loss, cracking, or a stress riser or (b) that exceed 6 percent depth, § 195.452(h)(4)(i). The IM regulations require a 60-day response for bottom-side dents with any indication of metal loss, cracking, or a stress riser, or top-side dents exceeding 3 percent depth, § 195.452(h)(4)(ii). The IM regulations require an 180-day response for dents (a) greater than 2 percent depth that affect pipe curvature at a girth weld or longitudinal seam weld, (b) on the top-side that are greater than 2 percent depth, or (c) on the bottom-side that are more than 6 percent depth, § 195.452(h)(4)(iii).

Proposal: PHMSA proposes to require an immediate response for dents interacting with metal loss, or for dents with cracking, gouging, or a stress riser regardless of orientation, except non-mechanical metal loss that does not exceed 10 percent depth. PHMSA proposes to require a near-term response for each of the existing 180-day dent conditions. Consistent with the requirements for gas transmission lines, PHMSA proposes to allow an operator to use an ECA process as an alternative for managing each of these dent conditions.

Discussion: First, PHMSA proposes to require an immediate response for dents with interacting features related to mechanical damage regardless of orientation. This proposal combines the existing immediate response requirements for top-side interacting dents and accelerates the existing 60-day criterion for bottom-side interacting dents. PHMSA intended the top- and bottom-side distinction to capture where excavation or mechanical damage is likely to occur, but operators can now distinguish mechanical damage and gouging features with dents from less injurious features. Delaying repair of a bottom-side dent known to interact with injurious gouging or mechanical damage is not justified on a hazardous liquid pipeline subject to

fatigue-related threats.¹⁰⁶ These interacting threats requiring immediate response are cracking, mechanical metal loss, gouging, and stress riser. PHMSA explains the threat of excavation and mechanical damage from interacting features in section IV.B.i above. The exclusion for metal loss not caused by mechanical damage (that is still below 10 percent) applies equally to hazardous liquid pipelines.

Second, PHMSA proposes to retain top-side dents exceeding six percent depth in the immediate response category and to include bottom-side dents exceeding six percent depth in the near-term response category. Despite one commenter recommending immediate response for all six percent dents, the risk of a new dent indication, though serious, is not universal.¹⁰⁷ A new bottom-side dent discovered during a baseline assessment is likely construction-related, a risk addressed by the interacting dent criterion.

Third, PHMSA proposes to retain each of the existing criteria listed for 180-day response in the near-term response category. The top- and bottom-side dent distinction remains relevant as the location affects the likelihood of whether the dent is restrained or unrestrained. The top-side two percent depth criterion adequately captures, and subsumes, the existing three percent dent requirement in the 60-day response category. Operators can respond to three percent dents safely in one year as a near-term condition. Finally, PHMSA proposes adding helical seams to the criterion for two percent dents that affect a girth weld or longitudinal seam weld, as they share identical risks.¹⁰⁸

¹⁰⁶ See Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 24 (citing Matt Romney et al., *The Power to Know More About Third Party Gouging*, (Pipeline Tech. Conf. 2022)).

¹⁰⁷ Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 10.

¹⁰⁸ See API RP 1183, sec. 6.5.1.3.

These are minor changes for dent response. All existing 180-day dent conditions would remain in the proposed near-term response category. Commenters did not generally suggest significant changes to the near-term criteria for dents.¹⁰⁹ The proposal effectively takes two of the current 60-day dent criteria and, based on severity, assigns one (bottom-side interacting dent) as an immediate condition and the other (three percent dents) as a near-term condition. The proposal also allows operators to use an ECA process to set an alternative response schedule for all dents.¹¹⁰

C. Anomaly Evaluation

Section 192.712 contains anomaly evaluation methods for metal loss, dents, and cracks. These methods require operators to conduct engineering-based calculations in determining a modern response schedule. PHMSA proposes to make select revisions to § 192.712, to add a dent ECA provision at § 192.712(c), and to promulgate a similar regulation for hazardous liquid pipelines at § 195.415.

i. Anomaly Evaluation for Dents by the Dent ECA

Existing Requirement: In 2022, PHMSA issued requirements at § 192.712(c) establishing procedures for gas operators to determine alternative dent response timelines using an ECA. INGAA filed a petition for judicial review challenging that regulation, and the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) subsequently remanded § 192.712(c)

¹⁰⁹ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, attach. 2 at 13.

¹¹⁰ See Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 5; Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 3; Enterprise, Comment, Docket ID PHMSA-2025-0019-0015 at 4.

to PHMSA for further consideration to address certain deficiencies in the rulemaking process.¹¹¹ No dent ECA process is yet included in the part 195 regulations for hazardous liquid pipelines.

Proposal: PHMSA proposes to add a dent ECA process at §§ 192.712(c) and 195.415(c) to allow operators to establish alternative response timelines for dent criteria under §§ 192.714 and 195.453.

Discussion: As a result of the significant advancements in pipeline technology that have occurred in recent years, operators can use ECA to model the characteristics of a dent with greater accuracy, producing strain and fatigue analyses that can be used to calculate the remaining life of a dent.¹¹² The traditional criteria for responding to dents only account for general characteristics such as depth, size, and location. Fatigue is not considered, which makes the traditional criteria overly conservative from an anomaly response perspective, particularly when an operator is willing to conduct an ECA.¹¹³

For these reasons, PHMSA proposes to allow operators to perform an ECA to establish an alternative response schedule for dents that would otherwise fall into the immediate or near-term response category.¹¹⁴ Commenters expressed overwhelming support for this concept. “The

¹¹¹ See Order on Pet. for Panel Reh’g, *INGAA v. PHMSA*, 114 F.4th 744 (D.C. Cir. Dec. 10, 2024) (No. 23-1173); *id.* at 753. See also *Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments: Corrections to Conform to Judicial Review*, 90 FR 3713, 3714 (Jan. 15, 2025).

¹¹² These include profile, geometry, strain sharpness and curvature, potential interacting threats, and whether a dent is restrained or unrestrained.

¹¹³ See Janine Woo, *Integrity Assessment of Dents in Pipelines Using Finite Element Analysis and Artificial Neural Networks*, at 2 (2019), available at: <https://ualberta.scholaris.ca/items/2e902116-cadb-4e17-a4c2-9a81ae81bde8> (noting several situations where dent criteria failed to screen injurious dents); Jian Zhao et al., *Standards and Methods for Dent Assessment and Failure Prediction of Pipelines*, *Petroleum Sci.* Vol. 19, 3029, at 3035 (Oct. 10, 2022).

¹¹⁴ See TC Energy, Comment, Docket ID PHMSA-2025-0019-0019, at 18 (“ECAs are a technically sound and appropriate method for evaluating dents in many scenarios” and “allow for a more detailed, physics-based understanding of strain behavior, material response, and potential crack presence”).

ability for operators to use an ECA to set an alternate timeline for responding to dents, which does not increase safety risk, can have great benefit to operators.”¹¹⁵

More accurate results and information can be obtained by following an approved ECA process, allowing operators to focus scarce resources on responding to dents that present a true integrity threat and avoiding unnecessary operations and maintenance activities and service disruptions. The ECA process also provides a level of safety that meets or exceeds the general depth measurements used in the traditional approach and results in significant cost savings (even considering upfront costs).¹¹⁶ For example, one operator found that 29 of 31 dents analyzed with level 3 FEA had a remaining life of 25 years or more, proving them safe.¹¹⁷ Another expects that more than half of the 251 dents excavated over the past decade under the response criteria did not present an integrity threat, so the ECA would allow them over \$10 million in cost savings.¹¹⁸ In its analysis of § 192.712(c), INGAA stated that a dent ECA process would reduce around 572 unnecessary excavations per year, saving even just a sampling of its gas transmission member-operators about \$85.8 million in repair costs.¹¹⁹

¹¹⁵ Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 15; *see* AGA & API, *Letter*, Docket ID PHMSA-2011-0023-0781 (Sept. 20, 2024) (noting that PHMSA’s ECA allows gas operators to “prioritize repairs and maintain gas deliverability” without impairing public safety or requiring that “operators expend additional resources to making repairs on piping that can be showing (through engineering analysis) to not be a threat”); Energy Transfer, Comment, Docket ID PHMSA-2025-0019-0020, at 6 (“Repair criteria for hazardous liquid pipelines that could affect HCAs should be updated to allow dent-strain engineering analysis to evaluate dents and determine whether the pipe is at risk of failure.”); Liquid Associations, Comment, PHMSA-2025-0019-0021, at 6 (requesting that PHMSA amend the hazardous liquid response criteria “to also allow operators the option to apply modern [ECA] methods to determine if dents are a threat to pipeline integrity”); TC Energy, Comment, Docket ID PHMSA-2025-0019-0019, at 18 (supporting § 192.712(c) as “a solid foundation for evaluating dents and mechanical damage anomalies on gas transmission pipelines”).

¹¹⁶ AGA & API, *Letter*, Docket ID PHMSA-2011-0023-0781 at 2 (noting that these engineering analyses “allow operators to be precise in how repairs are identified and prioritized, leading to more thoughtful and sophisticated approaches to pipeline safety, not only in [HCAs] but across [] pipeline systems more broadly”).

¹¹⁷ API & LEPA, economic comment, Docket ID PHMSA-2025-0019-0027 at 13.

¹¹⁸ Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 15.

¹¹⁹ Pet’r’s Unopposed Pet. for Panel Reh’g at 53, *INGAA v. PHMSA*, 114 F.4th 744 (D.C. Cir. Oct. 15, 2024) (No. 23-1173).

PHMSA proposes a dent ECA process at §§ 192.712(c) and 195.415(c) for gas and hazardous liquid pipelines that is substantially similar to the approach used in the 2022 Safety of Gas Transmission Rule.¹²⁰ With slight differences accounting for the commodities, PHMSA expects that the proposal similarly is appropriate for hazardous liquid pipelines. Edits provide clarity regarding acceptable procedures and improve structure without substantive difference intended.¹²¹ The ECA is available for dents less than 10 percent deep, which is consistent with an original requirement within § 192.712(c)(8) (2022), as depths exceeding this level introduce too much uncertainty.¹²² Conversely, “[t]esting has shown that plain dents (regardless of shape) with depths up to 10 percent of the pipe diameter (without coincidental metal loss, weld, or crack features) have the same failure pressure as plain line pipe,” making them well-suited for the ECA.¹²³

To address the concerns identified by the D.C. Circuit, PHMSA provides additional explanation in support of the dent ECA process below, with information about the estimated cost-savings provided in the preliminary regulatory impact analysis. As a threshold matter, PHMSA notes that the first edition of API RP 1183, *Assessment and Management of Pipeline Dents*, published in 2020, provides useful guidance on elements of an ECA on gas and hazardous

¹²⁰ 2022 *Safety of Gas Transmission Rule*, 87 FR at 52249–50, 52271. The Gas Pipeline Advisory Committee unanimously endorsed that approach during the rulemaking process. GPAC, *All GT Voting Slides*, Docket ID PHMSA-2011-0023-0656 at 47; PHMSA, *GPAC Meeting Slides March 26 to 28, 2018*, Docket ID PHMSA-2011-0023-0657 attach. 2 at 147–50.

¹²¹ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 3 (expressing uncertainty and concern with PHMSA’s review and no-objection of these ECA procedures).

¹²² See, e.g., Brian Leis et al., *Dent Strain and Stress Analyses and Implications Concerning API RP 1183 – Part II: Examples of Dent Geometry and Strain Analyses During Contact and Re-Rounding*, J. of Pipeline Sci. & Eng’g, Vol. 4, Iss. 1, at 15 (Mar. 2024), available at: <https://www.sciencedirect.com/science/article/pii/S2667143324000015?via%3Dihub>.

¹²³ API RP 1183, sec. 5.2.5; see ASME, B31 Code for Pressure Piping, B31.8-2018, *Gas Transmission and Distribution Piping Systems*, sec. 851.4.2 (2018) (marking a distinction for dents at 10 percent depth by permitting grinding to a depth of 10 percent regardless of length). Though the consensus ASME B31.8 industry standard advises repair of dents at depths above 6 percent, PHMSA finds that using its proposed version of ECA can permit dents to remain in service somewhat larger than this, up to 10 percent.

liquid pipelines. PHMSA considered the provisions in the first edition of API RP 1183 in developing the proposed ECA requirements and will consider any updates in the forthcoming second edition in developing the final rule in this proceeding.¹²⁴ With that said, the steps of the proposed ECA process for hazardous liquid pipelines are generally as follows.¹²⁵

First, an operator must identify any potential interacting threats or features. Interacting threats and coincidental features are critical to modeling and to assessing dents and may impact fitness-for-service.¹²⁶ Some key interacting threats include ground movement, external loading, fatigue, cracking, and corrosion that could affect the dent.¹²⁷ The extent of area within which to consider threats to the dent may vary depending on the threat.

Second, an operator must review the available ILI data to create a dent profile to model the dent. The shape parameter involves human judgment that can result in variance, which step six later helps to specify and to remove subjectivity.¹²⁸ Third, the profile of a dent that has been identified previously must be compared against any prior profiles. Fourth, loads acting on the dent, both present and any previous loads, must be identified as even past strain can impact dent fatigue.

Fifth, an operator must conduct a curvature-based strain analysis. For these purposes, strain is “assessed from ILI data using the shape and curvature of the dent as the basis for the

¹²⁴ API RP 1183, at 8. PHMSA does not propose generally incorporating the recommended practice but proposes the ECA must be consistent with that recommended practice and incorporating it at paragraph (c)(6). PHMSA will consider broader incorporation pending possible improvements in future editions of API RP 1183.

¹²⁵ The numerals correspond to the subparagraph under paragraph (c).

¹²⁶ API RP 1183, sec. 6.5.

¹²⁷ See API RP 1183, sec. 4.2.3.

¹²⁸ See Rhett Dotson et al., *Practical Challenges of Using the RP 1183 Shape Parameter Methods*, at 8 (Pipeline Pigging & Integrity Mgmt. Conf., Houston, Tx., Jan. 2025), available at: <https://ppimconference.com/wp-content/uploads/proceedings/167.pdf> (“the shape parameter approach has significant repeatability challenges based solely on the subjectivity in setting the baselines”).

strain estimation.”¹²⁹ This provides a quick and valuable computational analysis to ensure a dent does not exceed 10 percent strain level. Curvature-based strain analysis is based solely on the measured geometric dimensions of deformation and is limited in that it assumes the dent is a symmetrical plain dent and does not account for residual stress, interactions, loadings, or fatigue.¹³⁰ This assessment is a “precursor to fatigue life analysis” in a later step.¹³¹

Sixth, an operator must account for interacting conditions and loading by performing a finite element analysis (FEA) under API RP 1183.¹³² API RP 1183 sets out three levels of strain analysis depending on the type of dent and information available. Level 1 and 2 are screening analyses and apply to single-peak plain dents and assume the dent is free from cracking. Level 3 is a more rigorous analysis that applies to all dents, including interacting defects.¹³³ PHMSA proposes that a level 3 FEA be required for all dents for the following reasons.

Recent research casts doubt on the reliability of the other less rigorous level 1 or 2 screening tools in API RP 1183. The Canadian Energy Regulator (CER) found that the screening methods for estimating the strain of dents in API RP 1183 Table 6 “can lead to an underestimation of dent severity, potentially misclassifying injurious dents as non-injurious” with “the pipeline’s actual integrity below what is projected by API RP 1183.”¹³⁴ Based on these concerns, API issued an addendum removing table 6 and alerting operators that the “various

¹²⁹ API RP 1183, sec. 5.2.4.

¹³⁰ Curvature-based strain analysis will use a formula such as ASME B31.8, Appendix R, which does not take shear strain, circumferential extensional strain, and the pressure at the time of dent formation into account, all of which can have significant effects on dent strain.

¹³¹ API RP 1183, sec. 5.2.4.

¹³² PHMSA proposes to incorporate API RP 1183 by reference for purposes of this step in the analysis.

¹³³ API RP 1183, sec. 8.3.5.

¹³⁴ CER, SA 2025-01, *Evaluation of Dents in Pipe* (June 19, 2025), available at: <https://www.cer-rec.gc.ca/en/safety-environment/industry-performance/information-safety-advisories/safety-advisory/2025/safety-advisory-sa-2025-01-evaluation-dents-pipe.html>.

screening tools included in RP 1183, Table 6...is not the most conservative dent screening method in all cases” and recommending that dents assessed under its methods may require reevaluation.¹³⁵

Leading pipeline researchers have also found that “the screening criteria and the fatigue assessment methods at level 2 and below frequently lead to unconservative errors well in excess of 100 [percent]” with “the worst unconservative prediction approached -2500 [percent].”¹³⁶ By making assumptions about maximum strain and curvature forms—rather than taking the actual measurements, as these can migrate from the apex of the dent during its lifecycle due to formation, rebounding, and subsequent cycling—the less rigorous strain analyses are found to result in erroneous, often unconservative strain calculations, which negatively impacts the fatigue assessments.¹³⁷ Even with smooth, symmetrical dents, this strain analysis risks error, and that is more pronounced for asymmetric, kinked, and skewed dents.¹³⁸ FEA is inherently more accurate and requires fewer assumptions, allowing PHMSA to propose the reassessment safety

¹³⁵ API, *Addendum to API RP 1183 for Improved Dent Screening* (June 9, 2025), available at: <https://www.api.org/products-and-services/standards/important-standards-announcements/addendum-1-rp-1183>; see Brian Leis et al., *Dent Strain and Stress Analyses and Implications Concerning API RP 1183 – Part I: Background for Dent Geometry and Strain Analyses During Contact and Re-Rounding*, J. Pipeline Sci. & Eng’g, Vol. 3, Iss. 3, at 2 (Sept. 2023), available at: <https://doi.org/10.1016/j.jpse.2023.100143> (“It becomes evident that significant disparities can arise when results from Level 3 methods are compared to those of the simpler lower-level methods—even for smooth profile single-peak dents.”).

¹³⁶ Brian Leis et al., *Dent Strain and Stress Analyses and Implications for API RP 1183 – Part IIB: Fatigue-Life Prediction for Dented Pipes*, J. of Pipeline Sci & Eng’g, Vol. abst & secs. 9–10 (forthcoming May 14, 2026), <https://doi.org/10.1016/j.jpse.2026.100531>.

¹³⁷ Brian Leis et al., *Dent Strain and Stress Analyses and Implications Concerning API RP 1183 – Part II: Examples of Dent Geometry and Strain Analyses During Contact and Re-Rounding*, J. of Pipeline Sci. & Eng’g, Vol. 4, Iss. 1, at 20 (Mar. 2024), available at: <https://www.sciencedirect.com/science/article/pii/S2667143324000015?via%3Dihub>.

¹³⁸ Leis, *Dent Strain and Stress Analyses and Implications Concerning API RP 1183 – Part II*, at 32 (noting that the error permitted by the first edition of API RP 1183 is too large as a “±20[percent] error bound is large relative to the safety margin for cross-country pipelines, such that errors the order of 60[percent] become untenable.”).

factors discussed below, while higher safety factors may have been necessary with alternative screening analyses.¹³⁹

PHMSA's proposal includes specific language addressing ECA procedures that would generally be viewed as unobjectionable. That language should address the concerns raised by operators, though some sought greater flexibility to use lower-level screening tools than PHMSA is comfortable codifying based on the current data and edition of API RP 1183.¹⁴⁰ Data collected from evaluations of dents analyzed by level 3 FEA should lead to the development of more reliable level 1 and 2 procedures in the future.¹⁴¹ PHMSA will revisit the requirements for dent ECA procedures, including potential adoption of screening methods as alternatives to level 3 FEA, following its review of the expected forthcoming second edition of API RP 1183. In the meantime, operators are permitted to use the § 192.18(c) and § 195.18(c) process to submit procedures with alternative technology or approaches, including screening tools or simplified strain procedures demonstrated to produce safe results reliably under defined circumstances.

At step seven, the operator estimates the fatigue life of the dent. Fatigue life computes as cycles the pipeline can withstand before failure and is converted to a predicted minimum fatigue life in years. The fatigue life determines whether an alternative timeline can be applied to a dent

¹³⁹ See API RP 1183, sec. 8.3.

¹⁴⁰ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 3 (expressing concern with delay in review of § 192.18(c) notifications for dent ECA procedures from conflict in PHMSA staff review as "PHMSA has been expecting operators to conduct [FEAs] for all dents even though, the language in § 192.712(c)(6) states '[FEA], or other technology'" and requesting that "PHMSA should allow for us of 'other technology' than FEA). See also Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 33 (requesting use of a "valid fatigue life prediction model such as an analytical model or [FEA]"); Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 24 (similar).

¹⁴¹ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 34–35 (noting that those operators who have applied an ECA in the last few years "have gained valuable experience about how the ECA process for dents should be improved to enhance its efficiency").

that would otherwise warrant an immediate or near-term response.¹⁴² An “ideal 7-step analysis” for dents includes an “[a]ccurate estimate of remaining life using ‘reasonable’ safety factors.”¹⁴³ A safety factor accounts for variability in cyclic life that PHMSA has observed between models in its review of the application of a dent ECA. The effect is that the remaining fatigue life is divided by the safety factor to provide the reassessment factor. With a predicted fatigue life of 500 years, a safety factor of two results in a 250-year reassessment factor, while a safety factor of five results in a 100-year reassessment factor; as both reassessment factors exceed the reassessment periods, the dent ECA in this example would permit delayed response in either scenario.¹⁴⁴ API RP 1183 recommends that reasonable safety factors “from 2 to 5 have traditionally been applied to the fatigue life” in ordinary circumstances, though it may be higher with interacting features.¹⁴⁵ A higher safety factor than this is not necessary because PHMSA’s formulation does not permit an ECA in certain edge cases, like dents greater than 10 percent depth, and a separate response criteria without an ECA covers anomalies preferentially affecting susceptible welds.

For gas transmission pipelines, PHMSA proposes a reassessment safety factor of two. A safety factor of two is appropriate due to the reduced risk of cyclic fatigue. This was the minimum safety factor achieved to calculate a 90 percent probability of the calculations under

¹⁴² A dent with a fatigue life, with safety factor applied, exceeding the immediate or near-term response interval is an “other condition” and, as proposed §§ 192.714(d)(3) and 195.453(d)(3) provide, must be reassessed at the next scheduled reassessment unless the calculated fatigue life provides a shorter interval.

¹⁴³ *API/PRCI Joint Workshop on Dent Assessment & Engineering Analysis Methods*, at 39 (PRCI Aug. 9, 2018), available at: <https://www.prci.org/NewsEvents/MeetingsEvents/138344.aspx>; see API RP 1183, sec. 8.4.

¹⁴⁴ This example is representative of a typical ECA that PHMSA has observed in its analysis of data including through “other technology” requests even before it first offered a dent ECA in part 192.

¹⁴⁵ API RP 1183, sec. 8.4. See also *id.* secs. 6.5.1.2, 6.5.1.3 (safety factor of 10 for dent with known longitudinal weld or spiral weld interacting threats)

the fatigue life assessment models of API RP 1183.¹⁴⁶ A safety factor of two effectively divides results in half, corresponding to the half-life concept common in fitness-for-service standards.¹⁴⁷ Data reviewed by PHMSA has not shown a meaningful difference from a higher safety factor on gas transmission pipelines as these factors do not make a difference in whether safe dents exceed the reassessment interval to qualify for use of the delayed response.

For hazardous liquid pipelines, PHMSA proposes a reassessment safety factor of five. A higher safety factor is necessary for hazardous liquid pipelines to account for the effect of cyclic fatigue,¹⁴⁸ and a safety factor of five corresponds to the upper range recommended by API RP 1183.¹⁴⁹ The difference in the safety factor for gas (2) and hazardous liquids (5) reflects the fatigue calculation differences observed between the commodities. For example, a study found that service life for a repaired dent on a liquid pipeline is 10 years versus 100 years for a gas pipeline using composite wrap.¹⁵⁰

Finally, though PHMSA still proposes a notification and no-objection approach under §§ 192.18(c) and 195.18(c), PHMSA has revised the requirements of § 192.712(c) to express PHMSA's expectations more clearly for operator procedures, which should reduce review time

¹⁴⁶ See Rana, *Improve Dent/Cracking Assessment Methods*, at 46 (“Level 2 is the least conservative assessment model and cannot provide minimum factor of safety of 1 with high certainty when using mean curve and up to 0.8 with mean -1sd curve. For target minimum safety factors greater than 1, scaling factors are required across most certainty levels.”).

¹⁴⁷ See, e.g., API 510, *Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration*, sec. 6.5 (11th ed. 2022) (“Unless justified by an RBI assessment, the period between internal or on-stream inspections shall not exceed one-half the remaining life of the vessel...”); NACE, SP 0502-10, *Pipeline External Corrosion Direct Assessment Methodology*, sec. 6.6.1 (2010) (“[T]he maximum reassessment interval for each ECDA region shall be taken as one-half the calculated remaining life.”); API, Standard 653, *Tank Inspection, Repair, Alteration, and Reconstruction*, sec. 6.3.3.2(b) (5th ed. Nov. 2014) (similar).

¹⁴⁸ See Aaron Dinovitzer *et al.*, PR214-203804-R01, *Systematize 20 Years of Mechanical Damage Research*, at 291 (May 31, 2022), available at: https://primis.phmsa.dot.gov/rd/FileGet/17097/Systematize_20_Years_of_Mechanical_Damage_Research_V2.pdf. (“As noted, the estimated design lives for the gas pipeline are significantly longer than those calculated for the liquid pipeline; this is typical as liquid pipelines are recognized for having more aggressive pressure cycling conditions than their gas transmission counterparts.”).

¹⁴⁹ See API RP 1183, sec. 8.4.

¹⁵⁰ Dinovitzer, *Systematize 20 Years of Mechanical Damage Research*, at 293, fig. 3 & 4.

significantly.¹⁵¹ PHMSA continues to believe that dent ECA notifications are appropriate to ensure the effective administration of this unique and technically complex program, but invites comment on whether to modify the process. PHMSA may consider adopting a simple notification without requiring an advanced no-objection at the final rule stage. PHMSA also requests comment on whether a simple notification should be incorporated into annual reports instead, and, if so, what information should be collected there.

ii. Anomaly Evaluation for Metal Loss

Existing requirement: Gas and hazardous liquid pipeline operators are required to calculate PFP of metal loss anomalies using ASME B31G or R-STRENG. §§ 192.712(b), 195.452(h)(4), and 195.587. For gas transmission pipelines, an alternative remaining strength calculation can be used subject to the notification and no-objection process.

Proposal: PHMSA proposes to allow API 579 and Probable Profiles (Psqr), in addition to B31G and R-STRENG, to assess metal loss in §§ 192.714(b) and 195.415(b). Use of alternative technically accepted remaining strength models demonstrated to provide comparable results is also permitted. PHMSA proposes a 1.25 FPR to accommodate the use of Psqr in the immediate response criteria.

Discussion: After further technical review, PHMSA proposes to expand the acceptable models for calculating metal loss. Specifically, PHMSA proposes to amend §§ 192.712(b) and 195.415(b) to allow the use of API 579 and Psqr.¹⁵² As with R-STRENG and B31G, API 579 and

¹⁵¹ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 3 (expressing concern with delay in review of § 192.18(c) notifications for no-objection of dent ECA procedures).

¹⁵² API 579-1/ASME FFS-1, *Fitness-for-Service* (4th ed. Dec. 2021); John Kiefner et al., PR-218-183607-R01, *Peer Review of the Plausible Profile (Psqr) Corrosion Assessment Model*, Project Number EC-2-9 (PRCI Aug. 9, 2019). See also ASME, American Standard Code for Pressure Piping, B31G-2023, *Manual for Determining the Remaining Strength of Corroded Pipelines* (2023); J.F. Kiefner & P.H. Vieth, Pipeline Research Committee Project, PRCI PR-3-805, *A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe*, (Dec. 22, 1989), <https://www.osti.gov/biblio/7181509> (RSTRENG).

Psqr could be used without further notification or approval from PHMSA. See § 192.712(b)(2). API RP 579 has three levels of assessment for metal loss due to corrosion, which are equivalent to, or more rigorous than, a Modified B31G formula.¹⁵³ Leveraging the dramatic advancements in pipeline data, the Psqr model better represents corrosion features probabilistically in a pipeline by using a larger statistical distribution for more accurate and precise PFP calculation.¹⁵⁴ Peer-reviewed research indicates that Psqr classifies injurious defects reliably with fewer unnecessary excavations compared with other models.¹⁵⁵

To encourage further technological advancement, the proposed regulation will continue to permit operators to use other technically proven models (*i.e.*, those validated against the incorporated methods). However, PHMSA also proposes not to permit alternative methods that provide less conservative results. Since PHMSA proposes doubling the technically proven options specified in code, removing these less conservative options will reduce unnecessary notifications and improve safety.

The same models and methods are appropriate for both gas transmission and hazardous liquid pipelines. Currently, § 195.587 allows the same existing metal loss models for hazardous

¹⁵³ Kiefner & Associates, Inc., *Validity of Standard Defect Assessment Methods for the Alliance Pipeline Operating at 80% of SMYS*, at 6 (“The methods discussed above present trade-offs for the user between technical rigor and accuracy on the one hand, versus ease of use and reduced exactness on the other. In being modified from complex to simple, the exactness of the assessment decreases, but the simplifications were made so as to offset error with increased conservatism. So, one can say that more exact implies a less conservative computed result but not necessarily reduced safety because in using the more exact method the user is making a better quality estimate.”).

¹⁵⁴ RSI Pipeline Solutions, presentation, *Peer Review of the Plausible Profile (Psqr) Corrosion Assessment Model*, at 20 (PRCI Nov. 2019), available at: <https://www.prci.org/File.aspx?id=171572> (“The Psqr Model is more accurate and exhibits less scatter than the existing models. The model avoids over conservatism without compromising safety.”); Shenwei Zhang et al., IPC2020-9448, *Plausible Profile (Psqr) Corrosion Assessment Model: Refinement, Validation and Operationalization* (Jan. 15, 2021), available at: <https://doi.org/10.1115/IPC2020-9448> (“Validation results show the Psqr model is safe, and more accurate and precise than RSTRENG.”). Though Psqr uses a statistical distribution of possible predicted failure pressures, RSTRENG is based on one worst-case (and overly conservative) profile. RSI Pipeline, at 7.

¹⁵⁵ John Kiefner et al., PR 218-183607-R01, *Peer Review of the Plausible Profile (Psqr) Corrosion Assessment Model*, at 33 (PRCI Aug. 9, 2019).

liquid pipelines. PHMSA proposes to centralize the existing models, along with the two additional models, in a § 195.415(b) that is similar to § 192.712(b). The current § 195.587 requirement will reference the proposed § 195.415(b) for the metal loss assessment methods and will be relocated to § 195.585(c) to provide one IM regulation on corrosion.

Use of Psqr requires a different FPR for the metal loss response criterion to maintain the intended level consistent with other models as its “calculated failure pressures are generally higher than those calculated using RSTRENG or B31G.”¹⁵⁶ That Psqr specific FPR is incorporated in the proposed §§ 192.714 and 195.453. Given the increased precision in Psqr, PHMSA requests comments with technical information on whether this separate FPR is necessary or appropriate for corrosion anomalies calculated using Psqr.

iii. Anomaly Evaluation for Cracks

Existing requirement: Section 192.712(d) requires gas operators to analyze cracks by PFP using a technically proven fracture mechanics model appropriate to the failure mode, material properties, and boundary condition. Acceptable crack evaluation methods are not specified in § 192.712, though the regulation provides additional guidance. Fatigue analysis must be performed using an applicable fatigue crack growth law for a segment that is susceptible to cyclic fatigue or other loading. In addition, § 192.712(d)(3) provides for calculation based on pressure test assessments. Part 195 does not have a comparable provision, as PFP-based crack criteria for hazardous liquid pipelines are not yet codified by regulation.

Proposal: PHMSA proposes to codify examples of technically accepted fracture mechanic methods to assess cracks, including API 579 Level II or III, Modified Ln-Sec, and Raju-Newman equations. PHMSA proposes editorial clarifications to the existing regulation for crack anomaly

¹⁵⁶ Kiefner, *Peer Review of the Psqr Corrosion Assessment Model*, at 9.

evaluation at § 192.712(d) and to apply the same approach to hazardous liquid pipelines in § 195.415(d).

Discussion: Cracks must be evaluated by a model appropriate to a specific anomaly. PHMSA has issued guidance on accepted, technically proven crack evaluation models, such as the Newman-Raju Model, PipeAssess PI™ software, and PipeAssess PI™ software for brittle failure; and the Modified Log-Secant Model API RP 579-14 – Level II or Level III, CorLas™ software PAFFC Model, and PipeAssess PI™ software for ductile failure.¹⁵⁷

PHMSA proposes to incorporate these models, which are appropriate for both gas and hazardous liquid pipelines, by regulation (other than proprietary software models, which cannot be codified) to provide greater clarity and certainty. Operators may still use other methods demonstrated to produce safe results; software derived from the explicitly accepted methods is likely acceptable. PHMSA also proposes editorial revisions to § 192.712(d) to express more clearly the requirement to calculate remaining life based on the amount of time required for the crack to grow to failure size, and to apply the same approach to hazardous liquid pipelines at § 195.415(d). With the models incorporated, the reference to Paris' law can be removed.

For cracks that survive pressure testing, PHMSA proposes a non-substantive edit to the requirement at paragraph (d)(2) for clarity and to adopt a similar provision for hazardous liquid pipelines. Pressure test results provide different inputs for analysis than ILI results: pressure testing establishes a minimum PFP for cracks but does not provide any size information. The goal of the analysis is to postulate the largest crack that could survive the pressure test by varying the depth and length of crack features using a high toughness value.

¹⁵⁷ See 2019 Safety of Gas Transmission Rule, 84 FR at 52236; PHMSA, *[Batch One of] Frequently Asked Questions for the [2019 Safety of Gas Transmission Rule]: MAOP Establishment and Reconfirmation FAQs*, FAQ-40 (Sept. 15, 2020), available at: <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2023-06/Batch-1-FAQs-PHMSA-2019-0225-9-15-20.pdf>.

Finally, PHMSA proposes to consolidate the *in-situ* crack examination requirements at §§ 192.714 and 192.933 into a single provision at § 192.712(d)(3). This specifies requirements to perform *in situ* examination of exposed pipelines for indications of cracks identified during an ILI assessment to determine breadth of the cracking threat. PHMSA does not propose any substantive amendment to this requirement for gas transmission pipelines and proposes adopting a similar *in situ* provision for hazardous liquid pipelines in § 195.415(d)(3).

iv. Generally Applicable Components of Anomaly Evaluation

Existing requirement: Section 192.712 sets out anomaly evaluation methods for metal loss, dents, and cracks and includes material property values for gas transmission pipelines. Though part 195 does address consideration of uncertainty requirements, it does not contain any equivalent provision specifying evaluation methods. There are a few general supporting provisions in part 192: § 192.712(f) requires analysis to be reviewed and confirmed by a subject matter expert, § 192.712(g) lists records that must be retained for the life of the pipeline, and the § 192.712(e) material properties are addressed in the next section. In addition, §§ 192.710(d), 192.921(a)(1), 192.937(c)(1)(iii), and 195.452(c)(1)(i) each require an operator to account for uncertainties including tool tolerance.

Proposal: In both §§ 192.712(a) and 195.415(a), PHMSA proposes a requirement that analysis be conducted by a subject matter expert and include consideration of uncertainties like tool tolerance. PHMSA also proposes to consolidate the list of records.

Discussion: In addition to the technical content of §§ 192.712 and 195.415 discussed above, PHMSA proposes other editorial revisions. In paragraph (a), PHMSA proposes to require that all analysis be conducted by a subject matter expert and account for uncertainties, including tool tolerance. Locating these requirements in paragraph (a) clarifies that they apply widely to

anomaly response. The subject matter expert requirement, derived from the existing requirement at paragraph (g), is necessary to support the complex engineering analysis that underlies the other provisions of the regulation. The requirement to consider uncertainties, currently codified in different regulatory provisions, can be made more effective through consolidation in paragraph (a). Uncertainties include tool tolerance, detection probability, location accuracy, anomaly findings, and model accuracies.

The extensive list of records identified at § 192.712(g) is unnecessary. Each fall within the reach of the statement retained in the proposed paragraph (f) that “[a]n operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section.” Listing specific records is neither necessary nor appropriate given the section’s requirement to keep records of all actions.

D. Material Properties and Records

Proper records are key for accurate, reliable engineering analysis of anomalies. This includes toughness values, pipeline material property verification, and records.

i. Toughness and Material Property Values

Existing requirement: An operator must have information about the material properties of the pipe to complete the analysis required by § 192.712. Toughness is one key input. That information generally comes from traceable, verifiable, and complete (TVC) records. When that information is lacking, §§ 192.712(d)(3) and (e)(2)(i) provide several options to use for material toughness values, including:

- Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and manufacturer,
- a conservative Charpy v-notch value based on the ongoing § 192.607 process,
- default values of 13 ft-lbs for body cracks and 5 ft-lbs for cold weld, lack of fusion, and selective seam weld corrosion, which are reduced to 5 ft-lbs and 1 ft-lbs, respectively, on a segment with a history of reportable incidents caused by cracks,

- a full size equivalent Charpy v-notch upper-shelf level of 120 ft-lbs when using a pressure test, or
- an operator may pursue other appropriate Charpy v-notch values under a § 192.18(c) notification and no-objection process.

Part 195 does not yet contain similar processes or values for performing anomaly evaluations on hazardous liquid pipelines.

Proposal: PHMSA proposes to clarify that Charpy v-notch results are not the only valid toughness measure and to make other editorial revisions to set forth the material property-related requirements in paragraph (e). PHMSA proposes revised default toughness values of 19 ft-lbs for body cracks and 9 ft-lbs for those seam anomalies, or 14 ft-lbs and 4 ft-lbs, respectively, where the segment has experienced a reportable incident caused by cracking or crack-like anomalies. PHMSA proposes similar options at § 195.415(e) to obtain material properties values when needed to complete anomaly evaluation on hazardous liquid pipelines.

Discussion: Toughness is a material property that measures resistance to fracture when a crack is present. It is a necessary input for crack analysis and the dent ECA. The most accurate option is to use the actual pipe material property records that are TVC under § 192.607. But, because TVC is an ongoing, opportunistic process and anomaly evaluation may need to be conducted quickly to provide safe response, § 192.712(e) lists several other options to provide a material toughness value: conduct the TVC process, use values from an ongoing TVC process, use TVC properties available for comparable pipe, or use the provided default values that are generally applicable.¹⁵⁸ Editorial edits make this more clear.

The existing language specifies use of Charpy v-notch (CVN) toughness. But, as commenters note, Charpy v-notch tests are not the only valid way to determine toughness.¹⁵⁹ An

¹⁵⁸ By the end of a repair, TVC properties should be completed for that segment.

¹⁵⁹ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 11.

operator can also establish the fracture toughness of the material using J-resistance (J-R); crack tip opening displacement (CTOD); Drop Weight Tear Test (DWT); and Stress Intensity Factor (K).¹⁶⁰ PHMSA proposes to avoid unnecessarily limiting the toughness value to Charpy v-notch.

As another editorial matter, PHMSA proposes to locate all toughness options in paragraph (e), including those for use on assessments by pressure test that the current regulation list separately in (d)(3). The default value for results from pressure test assessments differs, but the toughness options themselves overlap, and PHMSA proposes no substantive change.

Next, PHMSA proposes to revise the provided default toughness values. Though toughness values generally should be derived from TVC records from the pipe or comparable pipe, when that information is not available § 192.712(e)(2)(i)(C) and (D) provide default, assumed values that are suitable for any situation. These values are slightly higher than may be needed in a given situation because they are intended to apply in an array of circumstances.¹⁶¹ PHMSA adopted the values in the 2019 Safety of Gas Transmission Rule to correspond with the 90th percentile and 98th percentile results from a 2016 analysis performed by Structural Integrity Associates submitted in comments on the rule.¹⁶²

¹⁶⁰ See, e.g., API RP 1176, table E.1 (basic fracture toughness properties, standards used to acquire the toughness value, and the specific application to the value); ASTM Int'l, ASTM E1820-25a, *Standard Test Method for Measurement of Fracture Toughness* (Mar. 1, 2025) (including test methods for measurement of K, J, and CTOD); Gery Wilkowski et al., PR-276-223814, *Pragmatic Application of MegaRule RIN 1 – 192.712 Toughness Values L2 and L3 Procedures*, at 26 (PRCI June 7, 2024) (“The fracture toughness of a material varies with many parameters. Thickness, loading rate, temperature, and constraint conditions (*i.e.*, bending versus tension loading) are the key parameters in the absence of environmental conditions (*i.e.*, hydrogen). On the upper shelf, it is important to remember there is no ‘true fracture toughness,’ but all the values can be related to each other.”).

¹⁶¹ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 10 (noting that default values, including those it recommends, necessarily are “the simplest and is a very conservative method given the lack of data”).

¹⁶² Peter Riccardella, Structural Integrity Assocs., *Statistical Evaluation of Charpy Toughness Levels for Gas Transmission Pipelines*, Docket ID PHMSA-2011-0023-0383 attach. 5 (July 7, 2016).

A wider pool of data now exists from applying those toughness values since issuance of the 2019 Safety of Gas Transmission Rule.¹⁶³ Having reviewed this larger data set, PHMSA agrees that it is reasonable to update the default values based on empirical observations. PHMSA proposes default toughness values of 19 ft-lbs for body cracks and 9 ft-lbs for those seam anomalies, or 14 ft-lbs and 4 ft-lbs, respectively, where the segment has experienced a reportable incident caused by cracking. These values correspond to the 90th and 98th percentile of observed toughness values—the same basis PHMSA used in the 2019 rule, but updated with more extensive data based on thousands of observations made since its issuance.¹⁶⁴ These values are based upon full size Charpy v-notch tests.¹⁶⁵ PHMSA proposes to display the revised default toughness values in a table in the regulatory text for readability.

To provide an appropriate level of conservatism where TVC records are lacking, the default toughness values for vintage seams use the values presented for the worst-performing seam type in the data: vintage DC-ERW.¹⁶⁶ PHMSA does not propose to incorporate PRCI level 2 and 3 methods since they are not presented as a consensus standard procedure, and there may be hurdles in making such reports publicly available as required by 49 U.S.C. § 60102(p). With

¹⁶³ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 10 (advocating to update the default values); TC Energy, Comment, Docket ID PHMSA-2025-0019-0019, at 5 (same); Wilkowski, PR-276-223814, *Pragmatic Application of MegaRule RIN 1 – 192.712 Toughness Values Level 1 Analyses*. The values from this study are publicly available in comments, please see Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 10.

¹⁶⁴ Gery Wilkowski, presentation, *Pragmatic Application of MegaRule RIN 1 – 192.712 Toughness Values* (PRCI Feb. 28, 2024).

¹⁶⁵ See A.A. Benzerga et al., *Size Effects in the Charpy V-Notch Test*, Int’l J. of Fracture, Vol. 116, 275, at 292–94, (2002), available at: https://www.researchgate.net/publication/227076576_Size_Effects_in_the_Charpy_V-Notch_Test. The behavior of pipeline steel is different depending on the operating temperature. For toughness, the higher the temperature, the more energy it takes to fracture. The material also exhibits ductile behavior in the upper-shelf zone. Lower-shelf toughness values coincide with lower temperature and exhibit brittle fractures.

¹⁶⁶ See Jiawei Wang, PR-350-233804, *Comprehensive Review of SSWC Assessment*, sec. 3.5 (PRCI Apr. 8, 2025) (“Using the existing models, no single value of toughness would enable reasonable prediction for the majority of the test results.”).

that said, PHMSA notes that an operator may still use an “other appropriate value” by following the notification and no-objection procedures until the § 192.607 process is complete.

The options to obtain strength and toughness values for gas transmission pipelines, including the default values, are appropriate for hazardous liquid pipelines. Gas transmission and hazardous liquid pipelines are both designed and manufactured in accordance with API Spec. 5L and welded in accordance with API Std 1104. The quality of the pipe material is the same and, while there may be vintage or commodity-specific differences in design between a typical gas transmission and hazardous liquid pipeline, the toughness values reflect the pipe material. Further, the default values represent an all-encompassing figure that should be equivalent for both. Like gas, while a liquid operator may use Grade A strength values for integrity assessments, this does not affect the requirement to base the design formula on § 195.106(b)(2) or the yield strength of 24,000 psi. For strength values, PHMSA proposes that operators use 30,000 psi or the SMYS that is the basis for the MOP.

PHMSA proposes including options to obtain needed material toughness values in § 195.415(e) similar to those in § 192.712(e). These options leverage an ongoing process for material verification under the proposed § 195.407 to obtain TVC material properties, use those from similar pipe, or obtain them from an ongoing verification process.

ii. Material Properties for Hazardous Liquid Pipelines

Existing requirement: Though § 192.607 provides gas operators with a process to obtain TVC pipeline material properties, part 195 does not provide a counterpart for hazardous liquid operators.

Proposal: PHMSA proposes to add § 195.407 to provide procedures to collect material properties information for hazardous liquid pipelines.

Discussion: Current regulations do not provide hazardous liquid pipeline operators with a path to collect necessary material property information.¹⁶⁷ Though not always needed to implement the historic hazardous liquid pipeline response criteria, the engineering-based criteria and ECA procedures proposed demand accurate information on pipeline dimensions, strength, and toughness. This is key as inaccurate records will skew the analysis by an unknown factor.¹⁶⁸ As hazardous liquid operators like Energy Transfer state, a process available under part 195 akin to § 192.607 would “allow operators the flexibility to develop their own material properties verification plan, [to] create a sampling program to document material properties, and [to] use recently developed technology to perform *in situ*, non-destructive examinations for determining the properties of unknown steel pipe material,” all in a cost-effective manner.¹⁶⁹

PHMSA proposes § 195.407, mirroring § 192.607, to provide a method for hazardous liquid operators to collect missing material properties records. One notable difference from § 192.607 is that no regulation directly triggers § 195.407 or obliges an operator to collect this information independently. Instead, § 195.407 is available for an operator to use as a process if they lack any information necessary to perform an integrity assessment, to evaluate an anomaly, or to perform a repair.¹⁷⁰ Together, the proposed §§ 195.407 and 195.415 ensure that operators have the information needed to carry out IM, particularly with the adoption of engineering-based response criteria that put more emphasis on accurate information on the material properties of the

¹⁶⁷ The only information on collecting material properties in part 195 is a requirement to perform destructive tensile tests to establish the yield strength of pipe with unknown material properties when determining the design pressure in § 195.106(b)(1). This requirement does not cover toughness testing.

¹⁶⁸ See, e.g., Banglin Lui et al., IPC2022-87337, *Application of Strain Based Assessment in Support of Operational and Mitigation Decisions*, at 7 (IPC Sept. 26-30, 2022) (“Data availability has been shown as a critical factor in executing [strain-based assessment]. Detailed pipeline and site-specific data could significantly improve the accuracy of the assessment. It is recognized that the options immediately available to a particular pipeline are often constrained by past and current practices of record keeping and at times changes in ownership.”).

¹⁶⁹ Energy Transfer, Comment, Docket ID PHMSA-2025-0019-0020, at 17–18.

¹⁷⁰ An operator may also wish to use this process for any other purpose.

pipeline. In proposing § 195.407, PHMSA has made certain editorial improvements. PHMSA requests comment from gas pipeline operators regarding whether they wish those to be incorporated in § 192.607.

iii. Recordkeeping for Hazardous Liquid Pipelines

Existing requirement: Section 195.404 describes various recordkeeping requirements, including requirements to have information on “the diameter, grade, and nominal wall thickness of all pipe.” These requirements, which have been in effect since the first hazardous liquid regulations, include a lifetime record retention provision for all repairs.¹⁷¹ See § 195.404(c)(1). Section 195.266 also lists certain construction-related records that must be retained for the life of the pipeline.

Proposal: PHMSA proposes to consolidate the recordkeeping requirements into § 195.404, adding requirements related to anomaly evaluation and material properties records.

Discussion: Records are an important component of pipeline safety compliance. For that reason, both the obligation to keep and maintain records—and the information that needs to be included in such records—must be clearly stated in the regulations. The proposed rule includes several changes to achieve these objectives.

First, PHMSA proposes to consolidate the design and construction-related recordkeeping requirements of § 195.266 into a single provision, § 195.404. That consolidation will eliminate duplicative provisions and provide operators with additional certainty. Second, in addition to repair records that are required under the existing regulation (which include remediation records like temporary pressure reductions), PHMSA proposes to add lifetime retention for anomaly evaluation calculations under § 195.415. A lifetime record retention requirement for these

¹⁷¹ *Transportation of Liquids by Pipeline—Requirements for the Design, Construction, Operation, and Maintenance*, 34 FR 15473, 15481 (Oct. 4, 1969).

calculations is necessary to inform any repairs that subsequently may be needed, and to evaluate threats continuously and manage risk under IM. Third, PHMSA proposes to require life of the pipeline retention of material property, pipe design, and pipe component records. Though this applies prospectively, operators of existing pipelines must retain any such records they have, plus records of actions taken to obtain any records under the proposed § 195.407.

These record-keeping requirements mirror those already required for gas pipelines. Operators should already have this information given longstanding requirements to know pipe dimensions and grade for hazardous liquid lines. Requiring these records ensures that operators have the information to carry out modern IM requirements, clarifies compliance, and provides consistency between part 192 and part 195.

E. Response, Repair, and Remediation Requirements

i. Discovery

Existing requirements: Pipeline response timelines begin on the date that a condition is discovered. Discovery occurs “when an operator has adequate information about a condition to determine the condition presents a potential threat to the integrity of the pipeline,” which must occur promptly, but no later than 180 days following assessment. Similar definitions are provided at multiple locations—for gas transmission pipelines at §§ 192.710(e) and 192.933(b) and for hazardous liquid pipelines at §§ 195.416(f) and 195.452(h)(2).

Proposal: In centralized §§ 192.714(b) and 195.453(b), PHMSA proposes to clarify the discovery provision to expedite discovery of immediate conditions, while synching discovery for other anomalies to the final ILI report. The 180-day deadline is unchanged.

Discussion: Discovery is critical because it begins the response timeline.¹⁷² Under current requirements for gas and hazardous liquid assessed pipelines, discovery is triggered when an operator has “adequate information.”¹⁷³ Commenters note that the “adequate information” requirement is poorly defined, resulting in uncertainty and inconsistent policy between operators and across states.¹⁷⁴

After an assessment an operator will often request a preliminary ILI report that is received within sixty days with final reports coming six to twelve months later after further data analysis is performed.¹⁷⁵ Operators often respond to immediate response conditions from the preliminary ILI report and consider less severe conditions discovered on receipt of the final report. This practice is appropriate and reasonable for safety, and PHMSA proposes to codify it to set a consistent requirement for discovery across gas and hazardous liquid pipeline systems.

PHMSA’s proposal to differentiate discovery based on the severity of the conditions will ensure prompt response to injurious anomalies while avoiding unnecessary excavations based on potentially premature analysis of less severe anomalies.¹⁷⁶ The final report may confirm a non-injurious condition, which is more likely as anomalies venture beyond the immediate thresholds.

¹⁷² See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 20 (“[T]he date of discovery, triggered once adequate information is obtained, is vitally important for regulatory compliance regarding remediation of anomalous threats within the requisite timeframe.”).

¹⁷³ See §§ 192.710(e); 192.933(b); 195.416(f); 195.452(h)(2).

¹⁷⁴ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 20.

¹⁷⁵ A random sampling by PHMSA inspectors shown an average of 27 days for preliminary report, and 100 days from submission to receive the final report. PHMSA understands that some tools may require more time to analyze results than others.

¹⁷⁶ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 20–21.

This balances comments on preliminary ILI reports and provides flexibility to accommodate various assessment methods and ILI tools.¹⁷⁷

ii. Non-HCA Hazardous Liquid Response Requirements

Existing Requirement: Though the gas response schedule applies to IM and other assessed pipelines, § 195.452(h) applies only to hazardous liquid pipelines that are subject to IM because they could affect HCAs.¹⁷⁸ Section 195.401(b) has a general obligation for non-IM repairs “[w]henever an operator discovers any condition that could adversely affect the safe operation of its pipeline system.”

Proposal: To address anomalies outside of IM, PHMSA proposes incorporating section 9.2.3 of API RP 1160 by reference at § 195.416.

Discussion: Stakeholders sought “clearer guidance about when [hazardous liquid] operators must correct a condition that could adversely affect the safe operation of a pipeline.”¹⁷⁹ That standard, which applies to hazardous liquid pipelines that are not subject to the IM requirements, dates to the adoption of the original version of part 195 in 1969.¹⁸⁰ Some commenters in this proceeding acknowledge that it is their practice to apply the IM response and remediation methods to anomalies outside of IM as a safety practice and for consistent

¹⁷⁷ See Gas Associations, Comment, Docket ID PHMSA-2025-0019-0022, at 20–21; Energy Transfer, Comment, Docket ID PHMSA-2025-0019-0020, at 33 (arguing that the current 180-day limit to confirm discovery is often impracticable for complex data integration); International Matex Tank Terminals, Comment, Docket ID PHMSA-2025-0019-0026 at 2 (Aug. 4, 2025) (recommending defining the discovery of a condition as the date the final report from the tool vendor is delivered to the operator); PST, Comment, Docket ID PHMSA-2025-0016, at 5 (stating that modern ILI vendors can analyze data faster, and that extending discovery delays remediation); TC Energy, Comment, Docket ID PHMSA-2025-0019-0019, at 10 (commenting that the current standard is ambiguous and that “PHMSA should consider amending the relevant provisions to explicitly define ‘discovery’ as the point at which an operator has both identified and evaluated the anomaly using appropriate engineering analysis”).

¹⁷⁸ A larger portion of hazardous liquid pipelines apply IM requirements than do gas pipelines, about 41 percent.

¹⁷⁹ Energy Transfer, Comment, Docket ID PHMSA-2025-0019-0015 at 19–20.

¹⁸⁰ *Transportation of Liquids by Pipeline*, 34 FR at 15481 (§ 195.402(c)); see *Transportation of Liquids by Pipeline*, 46 FR at 38369 (recodifying to § 195.401).

operations.¹⁸¹ PST encourages PHMSA to mandate that practice by regulation and to apply the IM response schedule to hazardous liquid pipelines in all locations.¹⁸²

Rather than following PST's suggested approach, PHMSA proposes requiring operators to follow API RP 1160. This adds a clear response requirement for hazardous liquid pipelines outside of areas that could affect HCAs without undermining the risk-based approach embodied in the IM regulations. The criteria of API RP 1160 section 9.2.3 are similar to those proposed in § 195.453 but include modifications that reflect the decreased risk present outside of HCAs. API RP 1160 defines immediate conditions to be mitigated within five days; near-term conditions to investigate and to respond within 270 days in critical locations, or 540 days otherwise; scheduled conditions to investigate and to schedule response; and monitored conditions to record and to monitor for changes that may require attention. It also includes temporary pressure reductions during repairs established either by considering remaining strength or by defaulting to a minimum of 20 percent.

Compared with the HCA response schedule proposed at § 195.453, API RP 1160 would allow non-HCA locations a degree of additional flexibility on anomaly evaluation and provide an opportunity to collect operational data and experience on alternative approaches in a lower-risk environment. It is comparable to the supportive non-HCA gas schedule with a shorter 540-day near-term response period (compared with two-years in gas transmission) befitting the higher fatigue present on a hazardous liquid pipeline. PHMSA believes requiring compliance with API RP 1160 will address the concerns about a lack of clear guidance in the existing regulations without eroding the risk-based framework underlying the IM regulations.

¹⁸¹ See Liquid Associations, Comment, Docket ID PHMSA-2025-0019-0021, at 48; Colonial, Comment, Docket ID PHMSA-2025-0019-0013, at 8.

¹⁸² PST, Comment, Docket ID PHMSA-2025-0019-0016, at 7.

iii. Temporary Pressure Reduction

Existing requirements: Operators may need to take temporary pressure reductions until a repair is completed under the existing regulations. In that scenario, part 192 requires gas pipeline operators to reduce pressure to: (1) 20 percent below the operating pressure, (2) the PFP times the class location design factor, or (3) PFP divided by 1.1. §§ 192.714(e), 192.933(a)(1)). Part 195 requires hazardous liquid pipeline operators under IM programs to reduce pressure to less than the PFP or, if that cannot be calculated, to take a 20 percent reduction from the operating pressure. § 195.452(h)(4)(i). Parts 192 and 195 both require operators to notify PHMSA if a pressure reduction exceeds 365 days or at an earlier point in time if an operator cannot meet the schedule and cannot provide for safety under a temporary pressure reduction. §§ 192.714(e), 192.933(a)(1), 195.452(h)(1).

Proposal: PHMSA proposes to remove the option to reduce to PFP divided by 1.1 and to add a design factor to the hazardous liquid PFP-based pressure reduction. These changes will result in comparable temporary pressure reduction options for both gas and hazardous liquid pipelines under §§ 192.714 and 195.453. Both gas and hazardous liquid operators may choose between a 20 percent reduction or a reduction to PFP times a design factor.

Discussion: Temporary pressure reductions ensure safety until a permanent repair is complete. A temporary pressure reduction must begin at discovery of an immediate condition or when a near-term timeline has lapsed.¹⁸³ PHMSA proposes to retain these requirements for gas and hazardous liquid pipelines. Because in these cases the anomaly causes the PFP or other critical strain to be near the pipeline's MAOP or MOP, the temporary reduction reestablishes the

¹⁸³ See *2022 Safety of Gas Transmission Rule*, 87 FR at 52246 (“During its meeting in late March 2018, the GPAC recommended PHMSA clarify that pressure reductions would be required for immediate conditions in non-HCAs and in cases where repair schedules could not be met.”).

margin of safety between pressure and the point of failure until pipeline strength can be restored. It is important that the reduction be to a level below that maximum operating pressure. A default 20 percent pressure reduction is effective at providing a necessary margin of safety. Though it may over account for a reduction in some cases, it ensures that pressure is reduced below the MAOP/MOP and has merit as a method an operator can quickly resort to without much further specific detail and calculations. Another appropriate option is a reduction to the PFP times the design factor, as this accounts for the anomaly failure pressure with uncertainties in anomaly dimensions and how those dimensions may have changed since the assessment.¹⁸⁴

PHMSA proposes these two options for gas and hazardous liquid operators alike. They are presently available for gas operators and are retained without substantive amendment. Similar options exist in current regulation for hazardous liquid operators, but PHMSA proposes adding the pipeline design factor at § 195.106 to the PFP-based reduction. PHMSA also proposes to remove a third option for gas transmission pipelines that does not provide equivalent safety. A reduction to 1.1 times the PFP does not reduce the MAOP in all cases, unlike the two methods that reasonably provide for safety. In fact, it may require no reduction whatsoever, risking invalidating the response timelines.¹⁸⁵ With two adequate options available, PHMSA proposes removing the less safe temporary pressure reduction option based on 1.1 times the PFP.

PHMSA proposes no change to the notifications required when a response timeline is not met and either a temporary pressure reduction cannot maintain pipeline safety or more than a year has passed with a reduction in place. These are notifications-simple in the existing

¹⁸⁴ See V. Chauhan & J. Brister, *A Review of Methods for Assessing the Remaining Strength of Corroded Pipe*, at 17–19, 44 (PHMSA Nov. 2009), available at: <https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=171> (PHMSA sponsored study comparing large data set of actual failure pressures with predicted values, including a result that the predicted value under B31G was less than 75 percent of the actual failure pressure).

¹⁸⁵ See *2022 Safety of Gas Transmission Rule*, 87 FR at 52246, 52273, 52277.

regulations. They do not currently reference paragraph (c), and PHMSA has explained in the past that only provisions that explicitly reference paragraph (c) trigger the no objection process.¹⁸⁶

PHMSA clarifies that these references to §§ 192.18 and 195.18 are to paragraphs (a) and (b).

Prior no-objection is not necessary for temporary pressure reduction notification provisions. It is sufficient to make PHMSA aware of outstanding repairs on pipeline systems for PHMSA to then determine any course of action that may be necessary.

Finally, the recordkeeping requirement within the gas transmission temporary pressure reduction provision at current § 192.714(e)(4) is redundant. Section 192.709 requires that operators keep records related to repair activity, including temporary pressure reductions. PHMSA proposes to drop the requirement within § 192.714(e)(4).

iv. General Repair Requirements

Existing requirements: The existing repair requirements for gas and hazardous liquid pipelines are located in various provisions. For gas pipelines, § 192.711 sets general procedural requirements stating that an operator must make permanent repairs “as soon as feasible” with cross-references to more requirements in §§ 192.714 and 192.933, a requirement that an operator take temporary measures until it repairs pipelines operating above 40 percent SMYS and a prohibition on welded patches as a means of repair in many situations. There is also a remediation provision in § 192.710(f) that cross-references other requirements. Section 192.713 sets general permanent repair methods for damage to gas transmission pipelines—including that operating pressure must be at a safe level during repair—while § 192.715 does so for welds and § 192.717 for leaks. Meanwhile, §§ 192.714(b) and 192.933(b) require repairs to be made in a

¹⁸⁶ See *Pipeline Safety: Class Location Change Requirements*, 91 FR 1608, 1644 (Jan. 14, 2026).

safe manner to prevent damage to persons, property, and the environment, with pressure reduced during repair operations.

For hazardous liquid pipelines, § 195.401 contains a general requirement that a pipeline may not be operated with a condition presenting an immediate hazard to persons or property; requires all operators correct a condition that could adversely affect the safe operation of a pipeline in a reasonable amount of time, while considering the risk to people, property, and the environment when prioritizing repairs; and references § 195.452 for IM repairs. Section 195.422 contains the general requirement to make repairs in a safe manner. Corrosion specific repair requirements are contained at §§ 195.585 and 195.587.

Proposal: PHMSA proposes streamlining and clarifying the general response requirements in §§ 192.711 and 195.422 and removing unnecessary cross-references. The general repair obligations are largely unchanged in these editorial revisions, though PHMSA proposes to add a non-IM response requirement for hazardous liquid pipelines following accepted industry practice.

Discussion: Currently, various sections in part 192 address different aspects of pipeline general repair. These requirements can be repetitive, overlapping, and key requirements may be overlooked because they are housed in different places. PHMSA proposes to consolidate the general repair requirements for gas into § 192.711. Removing the directional cross-references of § 192.711(b) does not obviate the clear requirement for pipelines assessed under IM or § 192.710 to follow § 192.714, as the proposed § 192.714(a) applicability text makes even more clear.

As amended, § 192.711 serves as a consolidated provision for general O&M repairs, merging existing §§ 192.711 and 192.713 without adding substantively different requirements. These requirements, including to maintain safe operating pressure during repairs, render

additional repair requirements at §§ 192.714(b) and § 192.933(b) unnecessary. Leaks and welds have certain specific procedures that may merit retaining their own repair requirements at §§ 192.715 and 192.717. PHMSA appreciates comment on streamlining other repair provisions such as those for construction, welding, and corrosion control.

PHMSA proposes similar changes to part 195, though the existing requirements are less cumbersome. The general requirement not to operate a hazardous liquid pipeline containing an immediate hazard remains in § 195.401(b) as an operational requirement. Otherwise, repair requirements are relocated to § 195.422. The general hazardous liquid requirement to make repairs in a safe manner and to protect persons and property is too vague as demonstrated by recent incidents resulting from ill-completed repairs.¹⁸⁷ For example, some operators have used Type A sleeves when Type B sleeves welded circumferentially to the pipeline were more appropriate. ADB-2024-01 notes two incidents of hydrogen-induced cracking of a hard spot that ruptured on a pipeline reinforced with a Type A sleeve.¹⁸⁸ PHMSA issued a May 2025 safety order requiring, among other things, an operator to inspect, to analyze, and to remediate dozens of Type A sleeves following a jet fuel spill.¹⁸⁹ A 2026 advisory bulletin noted these and other incidents where Type A sleeves were not managed correctly.¹⁹⁰ These incidents could have been prevented or mitigated with adequate repair method requirements.¹⁹¹

¹⁸⁷ See §§ 195.422, 195.452(h)(1). In comparison, gas transmission requires more specific repair methods.

¹⁸⁸ PHMSA, ADB-2024-01, *Pipeline Safety: Identification and Evaluation of Potential hard Spots—In-line Inspection Tools and Analysis*, 89 FR 908267 (Nov. 18, 2024).

¹⁸⁹ PHMSA, *USDOT Issues Safety Order for Upper Makefield Township Pipeline Leak* (May 2, 2025), available at: <https://www.phmsa.dot.gov/news/usdot-issues-safety-order-upper-makefield-township-pipeline-leak>.

¹⁹⁰ PHMSA, ADB-2026-01, *Pipeline Safety: Advisory Bulletin on the Integrity Risks of Type A Repair Sleeves*, 91 FR 3780, 3781 (Jan. 28, 2026).

¹⁹¹ See PST, Comment, Docket ID PHMSA-2025-0019-0016, at 8 (noting some hazardous liquid incidents involving Type A sleeves as indicative of needing improved repair requirements, while recommending no use of Type A sleeves be permitted on hazardous liquid pipelines).

Accordingly, PHMSA proposes to require in § 192.422 that all hazardous liquid operators select a permanent repair method that (a) is listed in ASME B31.4 Tables 451.6.2.9-1 and 451.6.2.9-2 or (b) is shown by reliable engineering tests and analyses to restore pipe serviceability permanently.¹⁹² Tables 451.6.2.9-1 and 451.6.2.9-2 set out examples of appropriate repair methods for given situations. Incorporating this consensus industry standard by reference would set a consistent, demonstrable level to meet for repairs. In addition, PHMSA proposes to allow other repair methods shown by reliable engineering tests and analyses to restore pipe serviceability permanently, which provides a complimentary performance-based option that matches existing language in § 195.585 for corrosion repairs. It preserves flexibility for operators to develop and to deploy alternative repair methods and helps to keep pace with technology.

V. Section-by-Section Analysis

§ 192.7 What Documents Are Incorporated by Reference Partly or Wholly in This Part

PHMSA proposes to incorporate the following material by reference:

1. For evaluation of both metal loss and cracking in § 192.712(b) and (d), API 579-1/ASME FFS-1, “Fitness for Service” (2021).
2. For the evaluation of metal loss in § 192.712(b), update reference to ASME B31G, “Manual for Determining the Remaining Strength of Corroded Pipelines” from the 2004 edition to the 2023 edition and correct cross references. This has the effect of authorizing Psqr.
3. For FEA in dent ECA procedures in § 192.712(c), API RP 1183, “Assessment and Management of Pipeline Dents,” First Edition, November 2020.

¹⁹² A comparable requirement is included in the requirement for a gas IM plan to conform to B31.8S, which has practices for selecting repair methods, and the requirement in § 192.713 that repairs restore serviceability.

4. For the evaluation of cracking in § 192.712(d), the Battelle NG-18 Modified LN-Sec and Raju-Newman equations by reference to Kiefner and Associates Final Report No. 13-002, “Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams” (January 2013). This is available on PHMSA’s website.

§ 192.18 How to Notify PHMSA

PHMSA proposes to remove §§ 192.714 and 192.933 from the reference list at § 192.18(c) as they would no longer include notifications subject to no-objection review.

*§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure
Reconfirmation: Onshore Steel Transmission Pipelines*

PHMSA proposes to update a cross-reference in this provision for content proposed to be relocated from § 192.713 to § 192.711(d).

*§ 192.607 Verification of Pipeline Material Properties and Attributes: Onshore Steel
Transmission Pipelines*

PHMSA proposes to replace the phrase “Charpy v-notch toughness” with “toughness,” clarifying that an operator may collect toughness information using Charpy v-notch tests and other valid methods.

§ 192.710 Transmission Lines: Assessments Outside of High Consequence Areas

PHMSA proposes to move discovery (§ 192.710(e)) and remediation (§ 192.710(f)) requirements to § 192.714. PHMSA proposes to merge the § 192.710(g) requirement to analyze and account for all available relevant information into the § 192.710(d) data analysis requirements. PHMSA also proposes to remove language that simply repeats requirements for anomaly evaluation and response in proposed §§ 192.712 and 192.714.

§ 192.711 Transmission Lines: General Requirements for Repair Procedures; § 192.713

PHMSA proposes to merge the general repair requirements in § 192.713 into § 192.711(d) and to remove § 192.713.

Proposed § 192.711 provides a general requirement to make repairs in a safe and timely manner, reducing pressure during repair operation. This would remain the primary repair requirement for offshore regulated gas gathering lines, Type A regulated gas gathering lines, and transmission lines not subject to §§ 192.710 or 192.933. PHMSA proposes to eliminate language in § 192.711(b) that simply restates response requirements in §§ 192.714 and 192.933.

§ 192.712 Analysis of Predicted Failure Pressure and Critical Strain Level

PHMSA proposes to adopt additional evaluation methods for metal loss and crack anomalies, to clarify dent ECA requirements, to revise default toughness values, and to make editorial improvements overall. The proposal includes the following.

In paragraph (a), the existing language restating the scope is redundant and replaced with general requirements from existing paragraphs (e)(1) and (f). These general requirements are to include tool tolerance and other uncertainties when evaluating anomalies and to have the analyses performed by a subject matter expert, not merely reviewed by one. These requirements apply to all analysis.

Paragraph (b) covers the evaluation of metal loss anomalies. PHMSA proposes to add two new models: API 579-1/ASME FFS-1 and Psqr (by updating reference to ASME B31G to the 2023 edition). With these additional evaluation methods, PHMSA continues to allow alternative equivalent remaining strength methods to be used, but would no longer permit other calculation methods that provide a “less conservative result.”

In paragraph (c), PHMSA proposes to reauthorize and to codify the dent ECA procedures. Editorial changes throughout should improve application of these procedures by combining similar steps and expressing expectations more clearly. PHMSA proposes a minimum reassessment safety factor of two to apply to the fatigue life for gas transmission pipelines. PHMSA also proposes that the default ECA procedures require level 3 FEA for strain analysis. Finally, PHMSA clarifies the notification process: a procedure submitted that conforms to the codified procedures is likely to be unobjectionable, while an operator retains the ability to submit procedures with alternative methods for PHMSA's review and no-objection.

In paragraph (d) for crack evaluation, PHMSA proposes to list several examples of acceptable fracture mechanics models for determining PFP and remaining life that are currently provided by PHMSA guidance: API 579-1/ASME FFS-1 level II or III, the Battelle NG-18 Modified Ln-Sec or Raju-Newman equations referenced in Appendix B of Report No. 13-002. Other technically proven fracture mechanics models continue to be available. PHMSA also makes editorial revisions, including moving into paragraph (d) the requirements for the *in-situ* examination of cracks that are currently in §§ 192.714(g) and 192.933(g).

Paragraph (e) contains material properties for anomaly evaluation. Editorial revisions make clearer the currently accepted options, including that toughness values include those from Charpy v-notch and other accepted means, and add values for cracks with pressure tests from paragraph (d)(3). In addition, PHMSA proposes to revise the default toughness values to use when an operator lacks adequate information on toughness and is unable to get it by other means.

Finally, PHMSA proposes to simplify the recordkeeping requirements by retaining existing language which includes all the records previously listed.

§ 192.714 Transmission Lines: Response Criteria

Currently § 192.714 defines response requirements for anomalies discovered on gas transmission pipelines not subject to IM. These requirements mirror those in § 192.933, except that operators have two years to repair conditions in § 192.714(d)(2), while it is one year for pipelines in covered segments in § 192.933(d)(2). Those different timelines would appear in § 192.714(d)(2), as PHMSA proposes listing response criteria and related requirements exclusively in § 192.714. These response requirements would apply to all gas transmission lines that are assessed and do not apply to offshore gas gathering, regulated onshore gas gathering lines, or Type R gas gathering lines as determined in § 192.8.

PHMSA proposes to locate at paragraph (b) the provision for discovery of an anomaly. This comes from similar provisions in §§ 192.710(e) and 192.933(b). Discovery in § 192.714(b) would continue to be defined as the point of time when an operator has adequate information to determine that an anomaly presents a potential threat to the integrity of the pipeline, subject to an 180-day deadline. PHMSA proposes to add that an operator's discovery procedures must include provisions for expediting the discovery of immediate response conditions and identify information and schedules used to complete discovery of all other conditions.

PHMSA proposes at paragraph (c) to incorporate § 192.712 for modern anomaly evaluation and to use the "failure pressure ratio" to replace prior language throughout individual response criteria of "PFP times the MAOP."

PHMSA proposes several editorial changes within § 192.714, including categorizing response schedules as (d)(1) "immediate," (d)(2) "near-term," and (d)(3) "other conditions;" and to clarify the requirements of other conditions, which combines existing text at paragraphs (c), (d)(3), and (f). The "other conditions" category encompasses conditions not specified in (d)(1) or

(2) and established in accordance with ASME B31.8S Figure 7.2.1-1 and the dent ECA that require response prior to the next scheduled reassessment or that must be evaluated during the next reassessment but that do not require response prior to that date. PHMSA also proposes editorial revisions at paragraph (d) to structure the existing response criteria.

PHMSA proposes the following substantive changes to the gas response criteria:

- Add an immediate response criterion for cracks with an FPR of 1.1 and below.
- Revise immediate response of cracks based on depth from 50 to 70 percent, while adding cracks of 50 to 70 percent depth as a near-term criterion.
- Revise the immediate response threshold for metal loss preferentially affecting certain susceptible longitudinal seams from 1.25 to 1.1 FPR.
- Add a specific FPR for immediate response metal loss anomalies evaluated using Psqr: 1.25 FPR in Class 1 locations and 1.5 in Class 2, 3 or 4 locations.
- Except from the interacting dent criteria non-mechanical damage metal loss that does not exceed 10 percent of the nominal wall thickness.

PHMSA proposes to reorganize requirements concerning remediation—both pressure reduction and repair—into paragraph (e) and to remove language that repeats remediation requirements elsewhere in part 192. The existing repair requirements at § 192.714(b) are largely redundant with the generally applicable revisions proposed to § 192.711. For temporary pressure reductions, PHMSA proposes to remove the PFP divided by 1.1 option; pressure must be reduced to 80 percent of the operating pressure at the time of discovery or the PFP times the design factor for the current class location. No change is proposed to the notification requirements, which are not subject to the no-objection review under § 192.18(c). Finally, PHMSA proposes to remove

pressure reduction-specific recordkeeping requirements as they are covered by recordkeeping requirements related to repair activity in § 192.709(c).

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

With the response schedule relocated to § 192.714, PHMSA proposes to remove the redundant response provisions and to revise § 192.933 to require that operators evaluate anomalies in accordance with § 192.712 and follow the response requirements in § 192.714. Section 192.714(d)(2) provides that near-term conditions discovered on covered segments require response in 1-year, consistent with longstanding requirements in § 192.933.

§ 195.3 What Documents Are Incorporated by Reference

PHMSA proposes to incorporate the following material by reference:

1. For evaluation of both metal loss and cracking in § 195.415(b) and (d), API 579-1/ASME FFS-1, “Fitness for Service” (2021).
2. For the evaluation of metal loss in § 195.415(b), update reference to ASME B31G, “Manual for Determining the Remaining Strength of Corroded Pipelines” from the 2004 edition to the 2023 edition. This has the effect of authorizing Psqr. This also applies to the evaluation of metal loss in §§ 195.585 and 195.588, which cross-reference to § 195.415(b).
3. For FEA in the dent ECA procedures in § 195.415(c), API RP 1183 “Assessment and Management of Pipeline Dents,” First Edition, November 2020.
4. For the evaluation of cracking in § 195.415(d), the Battelle NG-18 Modified LN-Sec and Raju-Newman equations via reference to Kiefner and Associates Final Report No. 13-002, “Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams” (January 2013). This is available on PHMSA’s website.

5. For the response requirements of pipelines assessed under § 195.416, API RP 1160, “Managing System Integrity for Hazardous Liquid Pipelines,” section 9.2.3, Third Edition, February 2019.

§ 195.18 How to Notify PHMSA

PHMSA proposes to add §§ 195.415 and 195.416 to the list of no-objection notifications in § 195.18(c).

§ 195.401 General Requirements

Proposed § 195.401(b) would continue to prohibit operating a pipeline with a condition representing an immediate hazard to persons or property. PHMSA proposes editorial amendments in paragraph (b) to move other repair-specific requirements to § 195.422 and to remove language that repeats requirements elsewhere in part 195.

§ 195.404 Maps and Records; § 195.266

PHMSA proposes to merge construction recordkeeping requirements of § 195.266 into general recordkeeping requirements in § 195.404 and to remove § 195.266.

In § 195.404, PHMSA proposes to add requirements that operators retain for the life of the pipeline records necessary to perform and to document the engineering analyses proposed in § 195.415. In addition, PHMSA proposes to require retention for the life of the pipeline records of material property, design, and pipe component records of newly installed pipe, any of these records that exist for existing pipelines, and records of those actions taken to conduct material property verification in § 195.407.

§ 195.407 Verification of Pipeline Material Properties and Attributes

PHMSA proposes a new section defining a process to collect missing material property information. This process mirrors the existing requirement at § 192.607. However, in part 195

this is not independently obligatory; it establishes opportunistic means to verify material properties by testing, examinations, or assessments during other maintenance activities.

§ 195.415 Anomaly Evaluation

PHMSA proposes to create § 195.415 that mirrors proposed § 192.712, providing harmonized methods for evaluating anomalies on hazardous liquid pipelines. This is necessary to support the engineering-based response criteria in proposed § 195.453. For hazardous liquid lines, this change supplements existing requirements to evaluate metal loss in §§ 195.585 and 195.588 with updated metal loss evaluation methods and adds new methods to evaluate dents and cracks or crack-like defects. In addition, PHMSA proposes at § 195.415(d)(3) to adopt requirements for the *in-situ* examination of cracks mirroring existing gas transmission requirements. See the discussion of § 192.712 for more detail on its provisions.

§ 195.416 Pipeline Assessments

PHMSA proposes to require pipelines subject to § 195.416 respond to anomalies following section 9.2.3 of API RP 1160 “Managing System Integrity for Hazardous Liquid Pipelines” for the purposes of defining discovery, anomaly evaluation, and repair requirements.

PHMSA proposes to update § 195.416(d) to use the notification provision of § 195.18(c). PHMSA also proposes an editorial amendment to remove a redundant and unnecessary cross reference to general requirements in § 195.401 as §§ 195.401 and 195.422 applicable to all hazardous liquid and carbon dioxide pipelines.

§ 195.422 Pipeline Repairs

PHMSA proposes to relocate repair-specific requirements in § 195.401(b) into this section. In addition, PHMSA proposes to require that operators select appropriate repair methods

in accordance with ASME B31.4, “Pipeline Transportation Systems for Liquids and Slurries” (2022) or a method demonstrated to permanently restore the serviceability of the pipeline.

§ 195.452 Pipeline Integrity Management in High Consequence Areas

PHMSA proposes conforming edits to accommodate PHMSA’s proposal to relocate the § 195.452(h) response requirements to a new section at § 195.453, which still applies within IM.

§ 195.453 Response Criteria for Hazardous Liquid Pipelines

PHMSA proposes to locate the IM response requirements in a dedicated section at § 195.453. Proposed § 195.453 mirrors the structure of proposed § 192.714.

PHMSA proposes a number of changes to the hazardous liquid IM response requirements. On the timelines, PHMSA proposes to eliminate the existing 60-day criteria and to extend the response timeline for 180-day conditions to a one-year timeline. Hazardous liquid response then provides for “immediate,” “near-term,” and “other” response conditions, similar to § 192.714. In some cases, specific criteria differ from those for gas transmission pipelines to account for the unique operational characteristics and threats of hazardous liquid pipelines.

On the specific response criteria, PHMSA largely proposes to replace or supplement the existing measurement-based criteria and to add engineering-based criteria, which § 195.453(c) require to be evaluated in accordance with new § 195.415. For immediate response, PHMSA proposes the following criteria:

- Metal loss with an FPR of 1.1 and below (1.25 and below when using Psqr)—which effectively replaces the existing requirement at 1.0 FPR—or 80 percent depth.
- Metal loss with an FPR of 1.1 and below preferentially affecting a susceptible longitudinal seam.
- Cracks with an FPR of 1.1 and below, or greater than 70 percent depth.

- A dent with an indication of cracking, gouging, stress riser, or metal loss, with an exception for corrosion metal loss caused by non-mechanical damage and that does not exceed 10 percent of the nominal wall thickness. This criterion merges existing immediate and 60-day conditions for dents with interacting features and adds the non-mechanical damage exception for corrosion metal loss. This differs from the proposed gas criteria by applying to top- and bottom-side dents.
- A dent on the upper two-thirds of the pipe with a depth greater than six percent, which is unchanged from the existing requirement.

For near-term response conditions, many of the existing 180-day conditions remain, though PHMSA proposes the following criteria subject to a one-year response timeline:

- Cracks with an FPR of 1.39 and below or a depth plus metal loss exceeding 50 percent but less than or equal to 70 percent of the nominal wall thickness.
- Metal loss with an FPR of 1.39 and below.
- Localized corrosion pitting with a depth exceeding 50 percent. This limits the existing depth-based near-term criteria for metal loss to one for isolated corrosion pitting.
- Metal loss preferentially affecting certain susceptible seam types. This limits the existing criteria for corrosion of or along certain susceptible longitudinal seams to corrosion preferentially affecting them. The seam includes the heat-affected zone. Unlike the gas transmission requirement, this criterion does not have an FPR factor.
- A gouge or groove greater than 12.5 percent of nominal wall. No change is proposed to this criterion.
- Dents located on the upper two-thirds of the pipe with a depth greater than two percent, or on the bottom third of the pipe with a depth greater than six percent. No

change is proposed to these criteria. The top-side criterion subsumes the existing 60-day criterion for top side dents with a depth exceeding three percent of the diameter, which would be eliminated.

- Dents located on the upper two-thirds of the pipe that affect pipe curvature at a girth weld, longitudinal seam weld, or helical (spiral) weld. This is an existing requirement to which PHMSA proposes to add helical welds.

In addition, the dent ECA proposed at § 195.415(c) is permitted as an exception to any of the listed dent immediate or near-term criteria.

PHMSA also proposes to revise response requirements concerning discovery (from § 195.452(h)(2)), temporary pressure reduction (from § 195.452(h)(1)) to add a design factor to the PFP-based option, and repair. These changes mirror proposals made in § 192.714.

§ 195.585 What Must I Do to Correct Corroded Pipe?; § 195.587

PHMSA proposes to merge § 195.587 into § 195.585(c) and to refer to § 195.415 for the methods to evaluate metal loss.

§ 195.588 What Standards Apply to Direct Assessment?

In § 195.588(c)(4)(i), PHMSA proposes to correct a cross reference and to refer to § 195.415 for the methods to evaluate metal loss.

VI. Legal Authority

A. Pipeline Safety Laws

PHMSA is authorized to administer the Federal Pipeline Safety Laws (49 U.S.C. § 60101 *et seq.*) pursuant to a delegation of authority from the Secretary of Transportation. 49 CFR 1.97. Section 60102 authorizes PHMSA to prescribe minimum safety standards for the design,

installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of gas and hazardous liquid pipeline facilities.

B. Section 60102(b) Practicability Factors

Section 60102(a) and (b)(2) require PHMSA to find that a safety standard prescribed pursuant to sections 60102 and 60109 is practicable and designed to meet the needs for gas pipeline safety and protecting the environment based on consideration of its appropriateness for the type of transportation, reasonableness, and upon a risk assessment of the costs and benefits.

PHMSA has preliminarily determined that the proposal is practicable, reasonable, cost-effective, technically feasible, and appropriate for gas transmission and hazardous liquid pipelines, respectively. Anomaly response schedules have been in effect for gas and hazardous liquid pipeline IM programs since the early 2000s, which operators have applied to respond to anomalies and to prevent incidents. The amendments here are consistent with the contours of those long-standing requirements, incorporating modern anomaly evaluation metrics accepted under multiple industry consensus standards. Gas operators have been applying the anomaly evaluation metrics for metal loss, dents, and cracking in § 192.712 for several years, another indication of their technical feasibility; those pipeline engineering concepts apply to either commodity equally. The FPR levels PHMSA proposes for immediate and near-term response, and the time to respond to each, are consistent with gas and hazardous liquid industry standards such as API RP 1160, API RP 1176, and ASME B31.8S. They reasonably provide for safety. PHMSA has discussed throughout this proposal how specific elements are tailored to be appropriate for gas and hazardous liquid pipelines, respectively. PHMSA makes requirements consistent where appropriate for both types of facilities while taking differences in operational characteristics into account where they justify a divergence to be appropriate for the facility.

PHMSA has also conducted a preliminary regulatory impact analysis (PRIA) that assesses the costs and benefits, and primarily finds it would be cost-effective.

These considerations result in a proposal PHMSA finds practicable for anomaly response to ensure pipeline safety, and PHMSA invites comment on these findings. As required by § 60102(b), this proposal will also be submitted to the Gas Pipeline Advisory Committee and Liquid Pipeline Advisory Committee for review of its technical feasibility, reasonableness, cost-effectiveness, and practicability. 49 U.S.C. §§ 60102(b)(2), (b)(4), 60115(c). PHMSA will announce the public meeting of the advisory committees in the *Federal Register* when it is scheduled, and an additional period of public comment will follow the meeting.

Though § 60102(g) presumes a rule will be effective within 30 days, PHMSA expects that the number of amendments proposed here reasonably will require 60 days from publication of a final rule to comply. PHMSA requests comment on this proposed effective date.

VII. Regulatory Analysis

A. Regulatory Planning and Review – Executive Orders 12866 and 14192

As required by Executive Order (E.O.) 12866 (*Regulatory Planning and Review*; 58 FR 51735 (Oct. 4, 1993)) and 49 CFR part 5, subpart B, the Office of Information and Regulatory Affairs within the Executive Office of the President’s Office of Management and Budget (OMB) has reviewed this proposed rule and determined that it is an economically significant regulatory action pursuant to E.O. 12866 section 3(f)(1) and, if finalized, likely to be a “major rule” as defined by the Congressional Review Act (5 U.S.C. § 804(2)). It is also a deregulatory action under E.O. 14192 (*Unleashing Prosperity Through Deregulation*; 90 FR 9065 (Feb. 6, 2025)).¹⁹³

¹⁹³ See OMB, M-24-20, *Guidance Implementing Section 3 of E.O. 14192* (Mar. 26, 2025), available at: <https://www.whitehouse.gov/wp-content/uploads/2025/02/M-25-20-Guidance-Implementing-Section-3-of-Executive-Order-14192-Titled-Unleashing-Prosperity-Through-Deregulation.pdf>.

B. Cost-Benefit Analysis – Section 60102, Executive Order 12866, and DOT Orders

Section 60102(b)(2) and (5) of the Pipeline Safety Laws require PHMSA for each rule to “prepare a risk assessment that...identifies the costs and benefits associated with a proposed regulatory change” and to make a “reasoned determination that the benefits, including safety and environmental benefits, of the intended standard justify its costs.” Likewise, E.O. 12866, as implemented by DOT Orders 2100.6B and 2100.7, requires agencies to regulate in the “most cost-effective manner,” to make a “reasoned determination that the benefits of the intended regulation justify its costs,” and to develop regulations that “impose the least burden on society.”

Consistent with 49 U.S.C. § 60102, E.O. 12866, and DOT Orders 2100.6B and 2100.7, PHMSA conducted a preliminary risk assessment of the economic impact of this proposed rule in a PRIA available in the docket for this rulemaking. The PRIA details the costs, cost savings, and benefits of this proposed rule. PHMSA’s proposal to incorporate technological and engineering advancements into the response requirements is expected to generate substantial cost savings for gas transmission, hazardous liquid, and carbon dioxide pipeline operators. Cost savings for gas transmission pipeline operators are projected to range from \$214.6 to \$241.7 million at a three percent discount rate, or \$208.4 to \$235.2 million at a seven percent discount rate. Cost savings for hazardous liquid and carbon dioxide pipeline operators are expected to be approximately \$148.5 million at a three percent discount rate or \$146 million at a seven percent discount rate. PHMSA expects that these cost savings will reduce costs for consumers to whom gas transmission, hazardous liquid, and carbon dioxide pipeline operators generally transfer a portion of their compliance costs. Those reduced costs to pipeline operators and the public are consistent with E.O. 14192, which establishes a Federal policy of alleviating

“unnecessary regulatory burdens” by reducing compliance costs and reducing the risks from non-compliance with burdensome regulations.

In addition to the quantified cost-savings, PHMSA expects that by accelerating responses to critical threats while eliminating unnecessary excavations, this proposed rule will improve public safety, benefit worker occupational safety, and have environmental, traffic congestion, and regulatory certainty benefits. This targeted approach reduces worker exposure to high-hazard environments, minimizes environmental degradation from heavy machinery, and alleviates economic costs from traffic congestion near work-zones of excavations. PHMSA has determined that the cost savings and benefits of each of the proposed rule elements would justify any associated costs notwithstanding the uncertainties identified.

C. Energy-Related Executive Orders 13211, 14154, and 14156

The President has declared in E.O. 14156 (*Declaring a National Energy Emergency*; 90 FR 8353 (Jan. 29, 2025)) a national emergency to address the inadequate energy development, production, transportation, refining, and generation capacity of the United States. Similarly, E.O. 14154 (*Unleashing American Energy*; 90 FR 8353 (Jan. 29, 2025)) asserts a Federal policy to unleash American energy by ensuring access to abundant supplies of reliable, affordable energy from (inter alia) the removal of “undue burden[s]” on the identification, development, or use of domestic energy resources. This proposed rule is consistent with both E.O. 14156 and E.O. 14154. The proposed rule will give operators flexibility to use modern anomaly evaluation techniques to prioritize their response to integrity threats, reducing repair of stable pipelines. That will in turn increase the transportation capacity and reliability of gas, hazardous liquid, and carbon dioxide pipelines, and improve pipeline operators’ ability to provide abundant, reliable, and affordable energy products in response to demand.

Though this is a significant action under E.O. 12866, it is not a “significant energy action” under E.O. 13211 (*Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use*; 66 FR 28355 (May 22, 2001)). The proposal will not have a significant adverse effect on supply, distribution, or energy use, as further discussed in the PRIA.

D. Availability of Materials to Interested Parties

49 U.S.C. § 60102(p) provides that “the Secretary may not issue a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge.”¹⁹⁴ Most of the updated consensus industry standards incorporated by reference in this proposed rule can be viewed online for free.

The remaining standards incorporated by reference in this proposed rule are reasonably available to interested parties. PHMSA has negotiated an agreement with API to make viewable copies of its standards available to the public at no cost, accessible at: <https://publications.api.org/IBR-Documents-Under-Consideration.aspx>. Though PHMSA was not able to reach a general agreement at this time with ASME to make its standards readily available online, the public may access the ASME standards proposed to be incorporated by reference in this rule by emailing the PHMSA standards library at phmsaphpstandards@dot.gov, and providing the requesters phone number, physical address, and email address. In addition, the material can be reasonably obtained by interested parties through the applicable publisher contact information listed in §§ 192.7 and 195.3.

¹⁹⁴ Additional information regarding the availability of standards PHMSA incorporates by reference may be found at: <https://www.phmsa.dot.gov/standards-rulemaking/pipeline/standards-incorporated-reference>.

E. Executive Order 13132: Federalism

PHMSA analyzed this proposed rule in accordance with the principles and criteria in E.O. 13132 (*Federalism*; 64 FR 43255 (Aug. 10, 1999)) and the Presidential Memorandum (*Preemption*; 74 FR 24693 (May 22, 2009)). Though the proposed rule may operate to preempt some State requirements, it would not impose any regulation that has substantial direct effects on the States, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government. Section 60104(c) of the Federal Pipeline Safety Laws prohibits certain State safety regulation of interstate pipelines. Under the Federal Pipeline Safety Laws, States that have submitted a current certification under section 60105(a) can augment Federal pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate. In that instance, the preemptive effect of the proposed rule would be limited to the minimum level necessary to achieve the objectives of the statutory authority under which the proposed rule is promulgated. Therefore, the consultation and funding requirements of E.O. 13132 do not apply.

F. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. § 601 *et seq.*) requires Federal agencies to consider the impact of their rules on small entities, to analyze alternatives that minimize those impacts, and to make their analyses available for public comment. Regulatory flexibility analysis is not required, however, where the agency head certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. DOT's implementing guidance—established consistent with E.O. 13272 (*Proper Consideration of Small*

Entities in Agency Rulemaking; 67 FR 53461 (Aug. 16, 2002))—is available online at <https://www.transportation.gov/regulations/rulemaking-requirements-concerning-small-entities>.

PHMSA has conducted an initial regulatory flexibility analysis, which has been made available in the docket for this rulemaking and is summarized below. Based on this analysis, PHMSA requests comment on whether, based on this initial analysis, the final rule would have a significant economic impact on a substantial number of small entities. The proposed rule would relieve regulatory burdens, resulting in cost-savings for small entities. A description of the reasons why PHMSA is considering this action and a succinct statement of the objectives of, and legal basis for, the proposed rule are described earlier in this proposed rule preamble.

Description and Estimate of the Number of Small Entities to Which the Proposed Rule Would Apply

PHMSA analyzed privately owned entities (inclusive of investor-owned entities) that could be impacted by the proposed rule, which are gas transmission and hazardous liquid pipeline operators. Based on SBA size standards under the North American Industry Classification System (NAICS) in effect as of March 17, 2023, small privately owned entities for companies in the pipeline transportation of natural gas sector are those with less than \$41.5 million in annual revenue, and crude oil pipelines have under 1,500 employees. PHMSA identified small entities operating under the applicable SBA threshold. PHMSA estimated approximately 614 small parent entities of gas transmission and hazardous liquid pipeline operators could be impacted.

Description of Projected Reporting, Recordkeeping, and Other Compliance Requirements of the Proposed Rule.

PHMSA analyzed the costs of compliance for the small gas transmission and hazardous liquid pipeline operators. The proposed rule is estimated to result in between \$208.4 and \$235.2

million in cost savings per year for gas transmission pipeline operators and \$148.5 million for hazardous liquid pipeline operators, at a three percent discount rate. Small entities equally share in the compliance cost and cost-savings.

The proposed rule involves several reporting and recordkeeping obligations, though they would be less burdensome than the existing requirements. Operators wishing to use the dent ECA are required to develop procedures to do so, and notify PHMSA for its no objection, a one-time, per operator cost that PHMSA estimates at approximately \$39,000. In addition, PHMSA proposes to reduce several existing notification requirements for gas transmission operators. PHMSA proposes to expand the accepted models to evaluate metal loss at § 192.712(b), which will reduce the notification needed to use them as technically accepted models. The proposal to clarify that toughness values can derive from Charpy V-notch or other valid tests, and to revise the default toughness values should both reduce the need for an operator to notify PHMSA of alternative default toughness values.

To estimate the impact of the compliance costs on small entities, PHMSA then calculated cost-to-revenue ratios using the calculated compliance costs of each small parent entity. PHMSA estimates that 26 to 28 percent of small entities would experience cost savings over 1 percent of their revenue, with 16 percent experiencing cost savings greater than 3 percent of their revenue.

Relevant Federal Rules Which May Duplicate, Overlap or Conflict with the Proposed Rule.

PHMSA did not identify any Federal rules that may duplicate, overlap, or conflict with the proposed rule. In fact, an objective of this proposed rule is to reduce duplicative or overlapping requirements for the general repair and response of gas and hazardous liquid pipelines, for example, the proposed consolidation of §§ 192.711 and 192.713.

Description and Analysis of Significant Alternatives to the Proposed Rule Considered.

PHMSA analyzed a number of alternatives to the NPRM, which are described in detail in Section 6 of the PRIA accompanying this NPRM. However, the impacts of the proposed rule are beneficial to small entities, as they will reap a proportional share of cost-savings and changes involving regulatory clarity and added models of analysis will reduce their compliance burdens. None of the alternatives would reduce the burden on small entities, while providing them commensurate benefit, as the proposed rule.

G. Unfunded Mandates Reform Act of 1995 (UMRA)

UMRA (2 U.S.C. § 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, as well as the private sector. UMRA establishes a statutory threshold requiring additional analysis for mandates on the private sector of \$100 million or more in 1996 dollars (\$203 million in 2024 dollars) in any given year. As explained in the PRIA, PHMSA does not expect that the proposed rule will impose unfunded mandates under the UMRA.

H. National Environmental Policy Act

The National Environmental Policy Act (NEPA, 42 U.S.C. § 4321 *et seq.*) requires that Federal agencies assess and consider the impacts of major Federal actions on the human and natural environment. PHMSA has prepared a draft environmental assessment considering the reasonably foreseeable environmental impacts of the proposed rule. A copy is available in the docket for this rulemaking. PHMSA invites comment on the environmental impacts of this proposed rule and will consider substantive comments before making a final determination.

I. Executive Order 13175

PHMSA analyzed this proposed rule according to the principles and criteria in E.O. 13175 (*Consultation and Coordination with Indian Tribal Governments*; 65 FR 67249 (Nov. 9, 2000)) and DOT Order 5301.1A (*Department of Transportation Tribal Consultation Policies and Procedures*), which require agencies to assure meaningful and timely input from Tribal government representatives when developing rules that significantly or uniquely affect Tribal communities by imposing “substantial direct compliance costs” or “substantial direct effects” on such communities, or the relationship or distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the proposed rule and does not expect it will affect Tribal communities or Indian Tribal governments significantly or uniquely, such that the consultation requirements of E.O. 13175 and DOT Order 5301.1A do not apply. The proposed rule’s regulatory amendments have a broad, national scope and should not affect Tribal communities significantly or uniquely, much less impose substantial compliance costs on Native American Tribal governments or mandate their action. Further, consultation with stakeholders was made available under E.O. 12866.

J. Paperwork Reduction Act

The Paperwork Reduction Act (44 U.S.C. § 3501 *et seq.*) and its implementing regulations at 5 CFR 1320.8(d) requires that interested members of the public and affected agencies have an opportunity to comment on information collection and recordkeeping requests. The following provisions of this rulemaking will result in minor changes to notification requirements and trigger recordkeeping requirements.

First, two new provisions may require hazardous liquid operators submit notifications to PHMSA. A new § 195.407 proposes to require hazardous liquid operators to notify PHMSA in advance of using an alternative sampling approach in accordance with § 195.18(a) and (b). Similarly, a new § 195.415 requires operators who perform an Engineering Critical Assessment (ECA) for dents to submit their ECA procedures to PHMSA. This submission must be made through the notification and no-objection process outlined in § 195.18(c). The submission may also include a request to use alternative technology or methodology for reliably identifying anomalies that would be actionable under the rule's requirements. Similar existing requirements for gas transmission operators under §§ 192.607 and 192.712 are unchanged, though PHMSA has updated burden estimates associated with dent ECAs and some other notifications under § 192.712 are removed.

In addition, PHMSA proposes operators maintain the following records for the life of the pipeline system:

- **Anomaly Evaluation Documentation:** Records necessary to reproduce any engineering analysis conducted in accordance with the new § 195.415. In addition to existing requirements to evaluate the remaining strength of metal loss anomalies, there are new analyses with associated recordkeeping for crack anomalies, seam corrosion anomalies, and dent ECAs
- **Material Property Actions:** Records of actions taken to gather material property information under the new § 195.407, including results, investigations, and analyses.
- **Material, Design, and Component Records:** PHMSA proposes a more specific list of required material property records that must be maintained. For steel pipelines

installed after the effective date of the rule, these records must be made and retained;
for all other pipelines, existing records must be retained.

Finally, PHMSA proposes editorial conforming edits to Form PHMSA F7100.2-1, the Annual Report for Natural and Other Gas Transmission and Gathering Pipeline Systems, and Form PHMSA F 7000-1.1, the Annual Report for Hazardous Liquid and Carbon Dioxide Pipeline Systems, to refer to the terms “immediate”, “near-term”, and “other” conditions as described in proposed §§ 192.714 and 195.453.

PHMSA will submit information collection requests to OMB for approval based on the requirements in this rule. The following information is provided for each information collection request: (1) title of the information collection; (2) OMB control number; (3) current expiration date; (4) type of request; (5) abstract of the information collection activity; (6) description of affected public; (7) estimate of total annual reporting and recordkeeping burden; and (8) frequency of collection. Requests for a copy of these information collection requests should be directed to Angela Hill by e-mail at angela.hill@dot.gov.

The information collection burden is estimated as follows:

1. Title: Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137-0522.

Current Expiration Date: 08/31/2026.

Type of Request: Revision of a currently approved information collection.

Abstract: This mandatory information collection covers the annual collection of data from operators of natural gas pipelines, underground natural gas storage facilities, and LNG facilities for annual reports, as required by § 191.17. Following the proposed amendments to § 192.714, PHMSA proposes to modify Form PHMSA F7100.2-1, the Annual Report for Natural and Other

Gas Transmission and Gathering Pipeline Systems, to change references to “Immediate”, “One-Year”, “Other”, and “Monitored” conditions to “Immediate”, “Near-Term”, and “Other” conditions. PHMSA does not expect this to cause operators to experience a change in burden.

Affected Public: Operators gas pipeline systems.

Annual Reporting and Recordkeeping Burden:

Estimated annual responses: 2,445.

Estimated annual burden hours: 104,596.

Frequency of Collection: On occasion.

2. Title: Hazardous Liquid Pipeline Assessment Requirements.

OMB Control Number: 2137-0605.

Current Expiration Date: 06/30/2028.

Type of Request: Revision.

Abstract: Operators of Hazardous Liquid Pipelines are required to document the continual assessment and evaluation of their pipelines’ integrity through inspection or testing, as well as remedial preventive, and mitigative actions. This mandatory record keeping requirement supports the U.S. Department of Transportation’s “SAFETY STRATEGIC GOAL” which targets three main strategic initiatives: managing risk and integrity, sharing responsibility, and providing effective stewardship. This goal enhances public health and safety by working toward the elimination of transportation-related deaths and injuries. This information is used by PHMSA to determine compliance with Federal pipeline safety regulations and is also used by Agency and State Officials to assist Federal and State pipeline safety inspectors who audit this information when they conduct compliance inspections and to provide background for failure investigations.

PHMSA proposes to modify this collection to include new notification and recordkeeping provisions from the Pipeline Safety: Repair Criteria NPRM. Under the proposal, hazardous liquid operators would be required to notify PHMSA in advance of using an alternative sampling approach in accordance with § 195.18(a) and (b) and operators who perform an Engineering Critical Assessment (ECA) for dents would be required to submit their ECA procedures to PHMSA through the notification and no-objection process outlined in § 195.18(c). PHMSA expects 710 operators to spend approximately 400 hours developing and submitting ECA documentation to PHMSA. Likewise, approximately 71 operators will incur an additional time burden complying with new recordkeeping requirements. The burden estimate below has been adjusted accordingly.

Affected Public: Operators of Hazardous Liquid and Carbon Dioxide Pipeline Facilities.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 11,369.

Total Annual Burden Hours: 629,097.

Frequency of Collection: On occasion.

3. Title: Gas Transmission Integrity Management in High Consequence Areas.

OMB Control Number: 2137-0610.

Current Expiration Date: 06/30/2028.

Type of Request: Revision of a currently approved information collection.

Abstract: This mandatory information collection request pertains to gas transmission operators jurisdictional to 49 CFR part 192 subpart O Gas Transmission Integrity Management Program. The information collection requires gas transmission operators in high consequence

areas to maintain a written integrity management program and keep records that demonstrate compliance with 49 CFR part 192 subpart O. Operators must maintain their integrity management records for the life of the pipeline, and PHMSA or State regulators may review it as a part of inspections. Gas transmission operators are also required to report to PHMSA certain actions related to their integrity management program. This information collection supports the DOT strategic goal of safety by reducing the number of incidents in natural gas transmission pipelines.

Affected Public: Operators of gas transmission pipeline systems.

Annual Reporting and Recordkeeping Burden:

Estimated number of responses: 1,772.

Estimated annual burden hours: 1,434,407.

Frequency of Collection: On occasion.

4.. Title: Hazardous Liquid Pipeline Operator Annual Reports.

OMB Control Number: 2137-0614.

Current Expiration Date: 03/31/2026.

Type of Request: Revision of a currently approved information collection.

Abstract: Section 195.49 requires operators of hazardous liquid pipelines to submit data on the safety of their pipelines annually, by June 15th, for the preceding calendar year. This information is used by PHMSA to identify trends in hazardous liquid pipeline accidents and to identify operators who have -poor safety records. Following the proposed amendments to § 195.453(d), PHMSA proposes to modify Form PHMSA F 7000-1.1, the Annual Report for Hazardous Liquid and Carbon Dioxide Pipeline Systems, to change “Immediate”, “60-day”, and

“Other” to “Immediate”, “Near-Term”, and “Other” respectively. PHMSA does not expect this to cause operators to experience a change in burden.

Affected Public: Operators of hazardous liquid pipeline systems.

Annual Reporting and Recordkeeping Burden:

Estimated annual responses: 950.

Estimated annual burden hours: 18,050.

Frequency of collection: Annually.

Comments on these information collections are invited on: (a) the need for the proposed collection of information for the proper performance of the functions of the Agency; (b) ways to enhance the quality, utility, and clarity of the information to be collected; (c) ways to minimize the burden of information collection on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques; and (d) the accuracy of the Agency’s estimate of the burden of the revised collection of information.

Send comments to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street N.W., Washington, D.C. 20503. Submitted comments on or before **[INSERT DATE 60 DAYS FROM DATE OF PUBLICATION]**.

K. Executive Order 13609 and International Trade Analysis

E.O. 13609 (*Promoting International Regulatory Cooperation*; 77 FR 26413 (May 4, 2012)) requires agencies to consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. Similarly, the Trade Agreements Act of 1979 (Pub. L. No. 96-39, as amended by Pub. L. No. 103-465), prohibits

Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards. Though PHMSA engages with international standards setting bodies to protect the safety of the American public, PHMSA has determined that the proposed regulatory amendments will not cause unnecessary obstacles to foreign trade.

L. Cybersecurity and Executive Order 14028

E.O. 14028 (*Improving the Nation's Cybersecurity*; 86 FR 26633 (May 17, 2021)) directs the Federal Government to improve its efforts to identify, deter, and respond to “persistent and increasingly sophisticated malicious cyber campaigns.” PHMSA has considered the effects of the proposed rule and expects that its regulatory amendments would not affect materially the cybersecurity risk profile for pipeline facilities or require pipeline operators to generate new security-sensitive records. This rule proposes to amend existing anomaly response obligations and operators are already familiar with anomaly response in their operation and maintenance plans and have evaluated their cybersecurity risks. Further, operators are encouraged to consult ongoing efforts by the Transportation Security Administration to strengthen cybersecurity and resiliency in the pipeline sector, and review cybersecurity guidance for pipeline operators issued by the Cybersecurity & Infrastructure Security Agency and the Pipeline Cybersecurity Initiative, which conduct ongoing activities to address cybersecurity risks to U.S. pipeline infrastructure. This guidance is available at www.cisa.gov/uscert/ncas/alerts.

VIII. Regulatory Text

List of subjects in 49 CFR part 192

Energy, Natural Gas, Pipeline Safety.

List of subjects in 49 CFR part 195

Energy, Petroleum, Pipeline Safety.

In consideration of the foregoing, PHMSA proposes to amend 49 CFR parts 192 and 195 as follows:

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

1. The authority citation for part 192 continues to read as follows:

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

2. Amend § 192.7 by

a. Adding paragraphs (b)(13) and (14),

b. Revising paragraph (c)(4),

c. Amending paragraph (c)(6) by removing the words “§ 192.714(c);” and “§ 192.933(c) and (d);”, and

d. Adding paragraph (g).

The revisions and additions read as follows:

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

* * * * *

(b) * * *

* * * * *

(13) API Recommended Practice 1183, Assessment and Management of Pipeline Dents, First Edition, November 2020, including errata 1 (January 2021) and addendum 1 (May 2024) (API RP 1183); IBR approved for § 192.712(c).

(14) API 579-1/ASME FFS-1, Fitness-For-Service, 2021 edition, December 2021 (API-579-1/ASME FFS-1); IBR approved for § 192.712(b) and (d).

(c) * * *
* * * *

(4) ASME/ANSI B31G-2023, Manual for Determining the Remaining Strength of Corroded Pipelines, 2023, (ASME/ANSI B31G); IBR approved for §§ 192.485(c), 192.632(a), 192.712(b) and 192.714.

* * * *

(g) Battelle Memorial Institute (Battelle), 505 King Avenue, Columbus, OH 43201; phone: (800) 201-2011; website: <https://www.battelle.org>.

(1) Kiefner & Associates, Final Report No. 13-002, “Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams,” January 3, 2013, (Report No. 13-002), IBR approved for § 192.712(d).

(2) [Reserved]
* * * *

§ 192.18 [Amended]

3. Amend § 192.18(c) by removing the text “§ 192.714,” and “§ 192.933,”.

§ 192.607 [Amended]

4. Amend § 192.607(b) by removing the phrase “Charpy v-notch toughness” and adding in its place the word “Toughness.”

§ 192.632 [Amended]

5. Amend § 192.632(c)(5) and (6) by removing the text “192.713” and adding in its place the text “192.711.”

6. Amend § 192.710 by revising paragraph (d) and removing paragraphs (e), (f), and (g) to read as follows:

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

* * * * *

(d) *Data analysis.* An operator must analyze and account for all relevant information in complying with this section to determine if a condition could adversely affect the safe operation of the pipeline. Personnel qualified by knowledge, training, and experience must analyze the data.

7. Revise § 192.711 to read as follows:

§ 192.711 Transmission lines: General requirements for repair procedures.

(a) An operator must make repairs in a safe and timely manner.

(b) An operator must maintain operating pressure at a safe level during repair operations.

(c) An operator may not use a welded patch as a means of repair, except as provided in § 192.717(b)(3).

(d) All conditions scheduled for repair under § 192.714, and each leak, imperfection, or damage that impairs serviceability found in a pipeline operated at or above 40 percent of the SMYS, must be:

(1) Permanently repaired by removing the anomaly through cutting out and replacing a cylindrical piece of pipe, or repairing the anomaly using a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe or other methods for leak repair in accordance with § 192.717.

(2) Until permanent repair is complete, take immediate temporary measures to protect the public, property, and the environment.

8. Revise § 192.712 to read as follows:

§ 192.712 Analysis of predicted failure pressure and critical strain level.

(a) *General.* Analysis of anomalies under this part must be performed by a qualified subject matter expert and include uncertainties in reported assessment results (including tool tolerance) and model accuracy when identifying and characterizing the type and dimensions of anomalies.

(b) *Corrosion metal loss.* To analyze corrosion metal loss, an operator must calculate the predicted failure pressure (PFP) of the pipe using ASME/ANSI B31G, R-STRENG, or API 579-1/ASME FFS-1 (incorporated by reference, *see* § 192.7). Another technically accepted remaining strength model may be used where demonstrated to provide comparable results.

(c) *Dents.* To perform an engineering critical assessment (ECA) of the strain and remaining life of dents with a depth of 10 percent or less of the pipe outside diameter, an operator must have and follow written procedures that are consistent with API RP 1183 (incorporated by reference, *see* § 192.7) and the following minimum requirements:

(1) Identify and evaluate potential threats that could affect the dent, paying particular attention to ground movement, external loading, fatigue, cracking, and corrosion.

(2) Review ILI data necessary to create a dent profile and identify any potential interacting features within an appropriate size dent area, including associated weld regions.

(3) Compare the dent profile for changes in depth and shape between the current ILI results and all previous results that showed the dent.

(4) Identify and quantify all previous and present loads acting on the dent.

(5) Perform pipeline curvature-based strain analysis using high-resolution deformation inspection data.

(6) Evaluate the strain level of the dent and interacting threat, loads, and welds using level 3 finite element analysis and quantify damage at the dent using the strain limit damage and ductile failure damage indicator.

(7) Estimate the fatigue life of the dent by level 3 finite element analysis using operational pressure data and an appropriate fatigue life prediction model with a safety factor of two or greater. Where the estimated fatigue life is less than the reassessment period under §§ 192.710 or 192.939, remediate dents in accordance with § 192.714.

(8) For dents with suspected cracking, conduct a crack growth rate assessment.

An operator must submit ECA procedures to PHMSA using the notification and no-objection process in § 192.18(c). As part of that submission, an operator may request to use another technology or methodology that is demonstrated to identify reliably anomalies that would be actionable when following the requirements in this section.

(d) *Crack and crack-like anomalies.* To analyze cracks and crack-like anomalies, an operator must determine PFP, crack growth, and remaining life (including corrosion rate for selective seam weld corrosion) using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), pipe and weld material properties, site conditions, and boundary condition used (pressure test, ILI, or other). These models include API 579-1/ASME FFS-1 level II or III, the Battelle NG-18 Modified Ln-Sec or Raju-Newman equations referenced in Appendix B of Report No. 13-002 (incorporated by reference, *see* § 192.7).

(1) An operator must calculate the remaining life of the pipeline based on the amount of time required for the crack to grow to a size that would fail at MAOP using a toughness value established in paragraph (e) of this section after determining the initial and final flaw size. Before reaching half of the remaining life predicted by the analysis, an operator must recalculate the

remaining life using the actual operating pressure history and any intervening assessment information; continue to repeat before half of the remaining life last calculated lapses.

(2) Where ILI data of the crack anomaly is not available and pressure test results are used, the crack analysis must calculate the largest potential crack size that could have survived the pressure test.

(3) Whenever a pipeline is exposed to examine an indication of a crack from an assessment or to complete any examination on a segment where cracking is determined to be a threat, an operator must perform a direct examination of known locations of cracks or crack-like anomalies using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. “In situ” examination must include performance and evaluation standards for accuracy of the type of defects and pipe material being evaluated.

(e) *Material properties.* In analyzing anomalies, an operator must use pipe and material properties that are documented in traceable, verifiable, and complete records or obtain any necessary data or information through the process specified in § 192.607(c) through (e). If any pipe and material properties are not yet documented, the operator must use the following:

(1) For material toughness, use one of:

(i) Toughness values from comparable pipe with known properties of the same vintage from the same steel and pipe manufacturer.

(ii) Toughness values based upon the ongoing material properties verification process specified in § 192.607.

(iii) The maximum Charpy v-notch toughness value in Table 1 to § 192.712(e)(1) for the type of crack and the operating history of the pipeline, but where assessment results are obtained by pressure test, use a full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.

Table 1 to § 192.712(e)(1) Default Full Size Charpy V-notch toughness values

Reportable incident on the pipeline segment caused by cracking or crack-like anomalies	Crack is on the pipe body	Crack is due to cold weld, lack of fusion, or selective seam weld corrosion anomalies
No	19.0 ft.-lbs.	9.0 ft.-lbs.
Yes	14.0 ft.-lbs.	4.0 ft.-lbs.

(iv) Alternative values demonstrated to provide appropriate toughness for crack-related conditions through the notification and no-objection process in § 192.18(c).

(2) For material strength, use Grade A pipe (30,000 psi) or the SMYS that is the basis for the current MAOP.

(3) For pipe wall thickness, diameter, and other data, use the values relied upon in establishing MAOP.

(f) *Records.* An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section.

§ 192.713 [Removed]

9. Remove § 192.713.

10. Revise § 192.714 to read as follows:

§ 192.714 Transmission Lines: Response criteria.

(a) *Applicability.* These response criteria apply to assessments of onshore gas transmission pipelines, except for pipelines that operate under an alternative MAOP established in accordance with §§ 192.112, 192.328, and 192.620.

(b) *Discovery of condition.* Discovery occurs when an operator has adequate information to determine that an anomaly presents a potential threat to the integrity of the pipeline. An operator must establish procedures for the discovery of anomalies that present a potential threat to the integrity of the pipeline, including all anomalies specified in this section. The procedures must identify the relevant sources of information and prescribe the criteria and schedule that will be used in discovery. The criteria and schedule in the procedures must include provisions for expediting the discovery of immediate conditions and for requiring that the discovery of any other anomaly needing response occur within 180 days of the date the ILI tool was retrieved or the date of the final observation.

(c) *Anomaly analysis.* Operators must follow the requirements in § 192.712 in determining predicted failure pressures, remaining life, and critical strain levels. As used in this section, the “failure pressure ratio” (FPR) is the predicted failure pressure divided by the MAOP at the time when discovery occurs. When applying FPR criteria to anomalies on pipe of Class 1 design pipe that is operated in accordance with § 192.611(a)(4), use the FPR criteria corresponding to Class 1.

(d) *Schedule for evaluation and remediation.* An operator must establish a schedule for remediating or monitoring each anomaly in accordance with this paragraph.

(1) *Immediate conditions.* Remediate the following anomalies immediately upon discovery, consistent with section 7 of ASME B31.8S (incorporated by reference, *see* § 192.7):

(i) Any of the following anomalies with an FPR of 1.1 and below:

(A) Metal loss, except when established using the plausible profiles method described in section 2.3(b) of ANSI/ASME B31G (incorporated by reference, *see* 192.7) use an FPR of 1.25 and below in Class 1 locations and 1.5 in Class 2, Class 3, or Class 4 locations.

(B) Metal loss preferentially affecting a detected longitudinal seam formed by direct current electric resistance welding, low-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0.

(C) Crack or crack-like anomaly.

(ii) Crack or crack-like anomaly with a depth plus any metal loss greater than either 70 percent of nominal wall thickness or the maximum sizing capabilities of the ILI tool.

(iii) Metal loss greater than 80 percent of nominal wall thickness.

(iv) A dent located between the 8:00 o'clock and 4:00 o'clock positions (upper 2/3 of the pipe) that has cracking, gouging, a stress riser, or metal loss (other than metal loss not caused by mechanical damage that does not exceed 10 percent of the nominal wall thickness), except where an ECA demonstrates that critical strain levels are not exceeded or that geometric strain levels are less than 10 percent.

(v) Any anomaly that requires immediate action in the judgment of the person designated by the operator to evaluate the assessment results.

(2) *Near-term conditions.* Remediate the following anomalies within 1 year of discovery for covered segments subject to § 192.933, and within two years of discovery for all other pipeline segments:

(i) The following dents, unless an ECA demonstrates that critical strain levels are not exceeded or that geometric strain levels are less than 10 percent:

(A) A smooth dent located between the 8:00 o'clock and 4:00 o'clock positions (upper 2/3 of the pipe) with a depth greater than six percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(B) A dent located between the 4:00 o'clock and 8:00 o'clock positions (lower 1/3 of the pipe) that has cracking, gouging, a stress riser, or metal loss (excluding metal loss not caused by mechanical damage that does not exceed 10 percent of the nominal wall thickness).

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

(ii) Any of the following anomalies with an FPR below 1.39 for Class 1 locations or below 1.5 in Class 2, Class 3, or Class 4 locations:

(A) Metal loss that is located at a crossing of another pipeline, that is in an area with widespread circumferential corrosion, or that could affect a girth weld.

(B) Metal loss preferentially affecting a longitudinal seam formed by direct current electric resistance welding, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0.

(C) A crack or a crack-like anomaly.

(iii) A crack or a crack-like anomaly with a depth greater than 50 percent but less than or equal to 70 percent of the nominal wall thickness.

(iv) Any other metal loss with an FPR below 1.39 for Class 2 locations, or below 1.50 for Class 3 and Class 4 locations.

(3) *Other conditions.* If an anomaly does not require a response under the criteria in paragraphs (d)(1) and (2) of this section, schedule response and remediation in accordance with Figure 7.2.1-1 in ASME B31.8S or the interval provided by § 192.712(c)(8). Any other anomaly, including all other dents managed with an ECA or that exceed 6 percent depth, must be recorded and monitored during subsequent assessments for any change that may require remediation.

(e) *Remediation and repair.* (1) An operator must use material property information meeting the requirements in § 192.712(e) in performing repairs.

(2) *Temporary pressure reduction.* Upon discovery of an immediate condition or when a near-term condition cannot be repaired within the time specified in paragraph (d)(2) of this section, an operator must take prompt action by temporarily reducing the operating pressure of the pipeline to a pressure at or below 80 percent of the operating pressure at the time of discovery or the predicted failure pressure times the design factor for the current class location. The temporary pressure reduction must remain in place until the condition is repaired. An operator must submit a notification under § 192.18(a)–(b) if:

(i) an anomaly cannot be repaired within the time limits of this section and safety cannot be maintained through a temporary pressure reduction or other remediation action, or

(ii) a temporary pressure reduction exceeds 365 days.

§ 192.719 [Amended]

11. Amend § 192.719(b) by removing the text “192.713” and adding in its place the text “192.711.”

12. Revise § 192.933 to read as follows:

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

An operator must comply with the requirements in §§ 192.712 and 192.714 in evaluating and responding to anomalies discovered on covered segments.

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

13. The authority citation for part 195 continues to read as follows:

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

14. Amend §195.3 by:

a. Redesignating paragraphs (b)(2) through (23) as follows:

Old paragraph	New paragraph
Paragraph (b)(2)	Paragraph (b)(3)
Paragraph (b)(3)	Paragraph (b)(4)
Paragraph (b)(4)	Paragraph (b)(5)
Paragraph (b)(5)	Paragraph (b)(6)
Paragraph (b)(6)	Paragraph (b)(7)
Paragraph (b)(7)	Paragraph (b)(8)
Paragraph (b)(8)	Paragraph (b)(10)
Paragraph (b)(9)	Paragraph (b)(11)
Paragraph (b)(10)	Paragraph (b)(12)
Paragraph (b)(11)	Paragraph (b)(14)
Paragraph (b)(12)	Paragraph (b)(15)
Paragraph (b)(13)	Paragraph (b)(16)
Paragraph (b)(14)	Paragraph (b)(17)
Paragraph (b)(15)	Paragraph (b)(18)
Paragraph (b)(16)	Paragraph (b)(19)
Paragraph (b)(17)	Paragraph (b)(20)
Paragraph (b)(18)	Paragraph (b)(21)
Paragraph (b)(19)	Paragraph (b)(22)
Paragraph (b)(20)	Paragraph (b)(23)
Paragraph (b)(21)	Paragraph (b)(24)
Paragraph (b)(22)	Paragraph (b)(25)
Paragraph (b)(23)	Paragraph (b)(26)

b. Adding paragraphs (b)(2), (b)(9), and (b)(13);

c. Revising new paragraph (b)(16);

d. Redesignating paragraphs (c)(1) through (7) as paragraphs (c)(2) through (8);

e. Adding new paragraph (c)(1);

f. Revising newly redesignated paragraphs (c)(3) through (4);

g. Redesignating paragraphs (g) through (i) as paragraphs (h) through (j)

h. Adding paragraph (g); and

i. Revising newly redesignated paragraph (j).

The revisions and additions read as follows:

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

* * * * *

(b) * * *

(2) API 579-1/ASME FFS-1, Fitness-For-Service, 2021 edition, December 2021 (API-579-1/ASME FFS-1); IBR approved for § 195.415(b) and (d).

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(9) API Recommended Practice 1160, Managing System Integrity for Hazardous Liquid Pipelines, Third Edition, February 2019, reaffirmed March 2024 (API RP 1160); IBR approved for § 195.416(g).

* * * * *

(13) API Recommended Practice 1183, Assessment and Management of Pipeline Dents, First Edition, November 2020, including errata 1 (January 2021) and addendum 1 (May 2024) (API RP 1183); IBR approved for § 195.415(c).

* * * * *

(16) API Specification 5L, Line Pipe, 46th edition, April 2018, including Errata 1 (May 2018), (API Spec 5L); IBR approved for §§ 195.106(b) and (e) and 195.407(b).

* * * * *

(c) * * *

(1) ASME/ANSI B16.5–2003, ‘Pipe Flanges and Flanged Fittings,’ October 2004, ASME/ANSI B16.5); IBR approved for § 195.407(e).

* * * * *

(3) ASME/ANSI B31G-2023, Manual for Determining the Remaining Strength of Corroded Pipelines, 2023, (ASME/ANSI B31G); IBR approved for §§ 195.415(b) and 195.453(d).

(4) ASME B31.4–2022, Pipeline Transportation Systems for Liquids and Slurries: ASME Code for Pressure Piping, B31, issued December 8, 2022, (ASME B31.4); IBR approved for §§ 195.110(a) and 195.422(b).

* * * * *

(g) Battelle Memorial Institute (Battelle), 505 King Avenue, Columbus, OH 43201; phone: (800) 201-2011; website: <https://www.battelle.org>.

(1) Kiefner & Associates, Final Report No. 13-002, Models for Predicting Failure Stress Levels for Defects Affecting ERW and Flash-Welded Seams, January 3, 2013, (Report No. 13-002); IBR approved for § 195.415(d).

(2) [Reserved]

* * * * *

(j) Pipeline Research Council International, Inc. (PRCI), 15059 Conference Center Drive Suite 130, Chantilly, VA 20151; phone: (703) 205-1600; website: www.prci.org.

(1) AGA Pipeline Research Committee, Project PR-3-805, A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe, December 22, 1989, (PR-3-805 (RSTRENG)); IBR approved for § 195.415(b).

(2) [Reserved]

* * * * *

§ 195.18 [Amended]

15. Amend § 195.18(c) by adding the text “§ 195.415, § 195.416,” after the text “§ 195.260,”.

§ 195.266 [Removed]

16. Remove § 195.266.

17. Revise § 195.401(b) to read as follows:

§ 195.401 General requirements.

* * * * *

(b) A pipeline segment containing a condition that presents an immediate hazard to persons or property may not be operated until the condition is repaired.

* * * * *

18. Amend §195.404 as follows:

- a. Republish the introductory text of paragraphs (a) and (a)(1),
- b. Redesignate paragraphs (a)(1)(vi) and (vii) as paragraphs (a)(1)(viii) and (ix),
- c. Add paragraphs (a)(1)(vi), (a)(1)(vii), and (a)(5),
- d. Revise paragraph (c), and
- e. Add paragraph (d).

The revisions and additions read as follows:

§ 195.404 Maps and records.

(a) Each operator shall maintain current maps and records of its pipeline systems that include at least the following information:

(1) Location and identification of the following pipeline facilities:

* * * * *

(vi) Overhead crossings;

(vii) Corrosion test stations;

* * * * *

(5) Depth and type of cover.

* * * * *

(c) Each operator shall maintain records of each inspection and test required by this subpart for the longer of 2 years or until the next inspection or test.

(d) Each operator shall maintain the following records for the life of the pipeline:

(1) The date, location, and description of each repair made, except that records related to repair made to parts of the pipeline system other than pipe may be kept for 1 year.

(2) Records necessary to reproduce analysis conducted in accordance with § 195.415.

(3) Records of actions taken in accordance with § 195.407, including results, investigations, and analyses.

(4) The total number of girth welds and the number nondestructively tested, including the number rejected and the disposition of each rejected weld.

(e) The following records must be made and retained for steel pipelines installed after **[INSERT EFFECTIVE DATE OF THE RULE]**, and existing records must be retained for all other pipelines:

(1) *Material properties.* Records documenting the pipe diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of pipe materials.

(2) *Pipe design.* Records documenting the location of the pipe and determination of internal design pressure, including any anticipated external pressures and loads.

(3) *Pipeline components.* Records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested. Flanges, fittings, branch connections,

extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters greater than 2 inches—or appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures—must have records documenting the manufacturing standard or specification in effect at the time of manufacture. Necessary material records include yield strength, ultimate tensile strength, and chemical composition.

19. Add § 195.407 to read as follows:

§ 195.407 Verification of Pipeline Material Properties and Attributes.

(a) *Verification of material properties and attributes.* Where an operator does not have, and uses this section to obtain, traceable, verifiable, and complete records for material properties and attributes, the operator must develop and implement procedures in accordance with this section. The procedures must include conducting nondestructive or destructive tests, examinations, or assessments to obtain the necessary information at each exposed pipe and component during: anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations associated with the replacement or relocation of pipeline segments that are removed from service.

(b) *Requirements for destructive tests:* At each test location, conduct tests on each pipe cylinder removed from the pipeline to obtain its material properties. Tests must be performed in accordance with API Spec 5L (incorporated by reference, *see* § 195.3).

(c) *Requirements for nondestructive tests.* An operator must:

(1) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on a comparison with the destructive test results on material of comparable grade and vintage;

(2) Account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses;

(3) Use test equipment properly calibrated for comparable test materials prior to usage; and

(4) At each test location, the necessary material properties must be determined at a minimum of five places in at least two circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.

(d) *Line pipe sampling requirements.* To verify the material properties and attributes for a population of multiple, comparable segments of pipe, except as provided in paragraph (d)(3), an operator must use a sampling program that meets the following requirements:

(1) *Establish populations.* An operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: diameter, nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. Segments may not be considered the same vintage for the purpose of defining a population under this section if either the dates of manufacture or construction of the segments are more than two years apart. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.

(2) *Samples required.* For each population, the operator must determine the material properties at all excavations that expose the pipe (except for pipeline segments exposed during excavation activities pursuant to § 195.442) associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, as follows:

(i) Completion of one excavation per mile rounded up to the nearest whole number or 150 excavations, whichever is fewer.

(ii) Prior tests conducted for a single excavation according to the requirements of paragraph (a) of this section may be counted as one sample under the sampling requirements of paragraph (d) of this section.

(iii) If the test results identify line pipe with properties that are not consistent with available information, existing expectations, or assumed properties used for past operations and maintenance, the operator must establish an expanded sampling program that is consistent with the requirements specified in paragraph (d)(3) of this section.

(3) *Alternative sampling approach.* An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (d)(2) of this section. The alternative sampling approach must:

(i) Use valid statistical bases designed to achieve at least a 95 percent confidence level that the material properties used in the operation and maintenance of the pipeline are valid; and

(ii) Address how the sampling approach will be expanded to address findings that reveal the material properties not consistent with all available information, existing expectations, or assumed material properties used for pipeline operations and maintenance in the past.

(iii) Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with § 195.18(a) and (b).

(e) *Components.* (1) An operator must verify the material properties for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances, that are:

(i) Larger than two inches in nominal outside diameter,

(ii) Material grades of 42,000 psi (Grade X-42) or greater, or

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

(2) An operator is not required to test for the chemical and mechanical properties of components at pump stations, meter stations, river crossing headers, mainline valve assemblies, valve operator piping, cross connections with isolation valves from the mainline pipeline, or breakout tanks.

(3) An operator must establish and document the ANSI rating or pressure rating of non-line pipe and associated material properties.

(4) An operator must base its procedures for establishing the material properties of non-line pipe components on the documented manufacturing specification for the components. If the specifications are not known, an operator may use manufacturer-stamped, marked, or tagged material pressure ratings and types to establish the pressure rating. An operator must document the method it uses to determine the pressure rating and the findings of that determination.

(f) *Up-rating.* The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and the maximum operating pressure is based on an assumed yield strength of 24,000 psi in accordance with § 195.106(b)(2).

20. Add § 195.415 to read as follows:

§ 195.415 Anomaly evaluation.

(a) *General.* Analysis of anomalies under this part must be performed by a qualified subject matter expert and include uncertainties in reported assessment results (including tool tolerance) and model accuracy when identifying and characterizing the type and dimensions of anomalies.

(b) *Corrosion metal loss.* To analyze corrosion metal loss, an operator must calculate the predicted failure pressure (PFP) of the pipe using ASME/ANSI B31G, R-STRENG, API 579-1/ASME FFS-1 (incorporated by reference, *see* § 195.3). Another technically accepted remaining strength model may be used where demonstrated to provide comparable results.

(c) *Dents.* To perform an engineering critical assessment (ECA) of the strain and remaining life of dents with a depth of 10 percent or less of the pipe outside diameter, an operator must have and follow written procedures that are consistent with API RP 1183 (incorporated by reference, *see* § 195.3) and the following minimum requirements:

(1) Identify and evaluate potential threats that could affect the dent, paying particular attention to ground movement, external loading, fatigue, cracking, and corrosion.

(2) Review ILI data necessary to create a dent profile and identify any potential interacting features within an appropriate size dent area, including associated weld regions.

(3) Compare the dent profile for changes in depth and shape between the current ILI results and all previous results that showed the dent.

(4) Identify and quantify all previous and present loads acting on the dent.

(5) Perform pipeline curvature-based strain analysis using high-resolution deformation inspection data.

(6) Evaluate the strain level of the dent and interacting threats, loads, and welds using level 3 finite element analysis (FEA) and quantify damage at the dent using the strain limit damage and ductile failure damage indicator.

(7) Estimate the fatigue life of the dent by level 3 FEA using operational pressure data and an appropriate fatigue life prediction model with a safety factor of five or greater. Where the

estimated fatigue life is less than the reassessment period under §§ 195.416 or 195.452, remediate dents in accordance with §§ 195.416 or 195.453.

(8) For dents with suspected cracking, conduct a crack growth rate assessment.

Submit ECA procedures to PHMSA using the notification and no-objection process in § 195.18(c). As part of that submission, an operator may request to use another technology or methodology that is demonstrated to identify reliably anomalies that would be actionable when following the requirements in this section.

(d) *Crack and crack-like anomalies.* To analyze cracks and crack-like anomalies, an operator must determine PFP, crack growth, and remaining life (including corrosion rate for selective seam weld corrosion) using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), pipe and weld material properties, site conditions, and boundary condition used (pressure test, ILI, or other). These models include API 579-1/ASME FFS-1 level II or III, the Battelle NG-18 Modified Ln-Sec or Raju-Newman equations referenced in Appendix B of Report No. 13-002 (incorporated by reference, *see* § 195.3).

(1) An operator must calculate the remaining life of the pipeline based on the amount of time required for the crack to grow to a size that would fail at MOP using a toughness value established in paragraph (e) of this section after determining the initial and final flaw size. Before reaching half of the remaining life predicted by the analysis, an operator must recalculate the remaining life using the actual operating pressure history and any intervening assessment information; continue to repeat before half of the remaining life last calculated lapses.

(2) Where ILI data of the crack anomaly is not available and pressure test results are used, the crack analysis must calculate the largest potential crack size that could have survived the pressure test.

(3) Whenever a pipeline is exposed to examine an indication of a crack from an assessment or to complete any examination on a segment where cracking is determined to be a threat, an operator must perform a direct examination of known locations of cracks or crack-like anomalies using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. *In situ* examination must include performance and evaluation standards for accuracy of the type of defects and pipe material being evaluated.

(e) *Material properties.* In analyzing anomalies, an operator must use pipe and material properties that are documented in traceable, verifiable, and complete records or obtain any necessary data or information through the process specified in § 195.407. If any pipe and material properties are not yet documented, the operator must use the following:

(1) For material toughness, use one of the following:

(i) Toughness values from comparable pipe with known properties of the same vintage from the same steel and pipe manufacturer.

(ii) Toughness values based upon the ongoing material properties verification process specified in § 195.407.

(iii) The maximum Charpy v-notch toughness value in Table 1 to § 195.415(e)(1) for the type of crack and the operating history of the pipeline, but where assessment results are obtained by pressure test, use a full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.

Table 1 to § 195.415(e)(1) Default Charpy V-notch toughness values

Reportable incident on the pipeline segment caused by cracking or crack-like anomalies	Crack is on the pipe body	Crack is due to cold weld, lack of fusion, or selective seam weld corrosion anomalies
No	19.0 ft.-lbs.	9.0 ft.-lbs.
Yes	14.0 ft.-lbs.	4.0 ft.-lbs.

(iv) Alternative values demonstrated to provide appropriate toughness for crack-related conditions through the notification and no-objection process in § 195.18(c).

(2) For material strength, use Grade A pipe (30,000 psi).

(3) For wall thickness, diameter, and other data, use the values relied upon in establishing the operating stress.

21. Amend § 195.416 by revising paragraph (d), removing and reserving paragraph (f), and revising paragraph (g) to read as follows:

§ 195.416 Pipeline assessments.

* * * * *

(d) *Other technology.* Operators may elect to use other technologies if the operator demonstrates, subject to the notification and no-objection process in § 195.18(c), that the technology can provide an equivalent understanding of the condition of the line pipe for the threat being assessed.

* * * * *

(f) [Reserved]

(g) *Remediation.* An operator must discover and address anomalies identified during integrity assessments under this section in accordance with § 195.453(b) and API RP 1160, section 9.2.3 (incorporated by reference, *see* § 195.3).

* * * * *

22. Revise § 195.422 to read as follows:

§ 195.422 Pipeline repairs.

(a) An operator must repair within a reasonable time any condition that could adversely affect the safe operation of a pipeline. Prioritize repairs considering the risk to people, property, and the environment.

(b) The operating pressure of the pipeline segment must be maintained at a safe level during repair operations to prevent damage to people, property, or the environment.

(c) Permanent pipeline repairs must be selected in accordance with the provisions in ASME B31.4, Tables 451.6.2.9-1 and 451.6.2.9-2 (incorporated by reference, see § 195.3) or by another method shown by reliable engineering tests and analyses to restore the serviceability of the pipe permanently.

(d) No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities unless it is designed and constructed as required by this part.

23. In § 195.452, revise paragraph (f)(4) and remove and reserve paragraph (h) to read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

* * * * *

(f) * * *

(4) Discovery and response to anomalies in accordance with § 195.453 and information analysis.

* * * * *

24. Add § 195.453 to read as follows:

§ 195.453 Response Criteria for Hazardous Liquid Pipelines

(a) *General.* Anomalies discovered during an integrity assessment of a covered segment must be addressed in accordance with this section.

(b) *Discovery of condition.* Discovery occurs when an operator has adequate information to determine that an anomaly presents a potential threat to the integrity of the pipeline. An operator must establish procedures for the discovery of anomalies that present a potential threat to the integrity of the pipeline, including all anomalies specified in this section. The procedures must identify the relevant sources of information and prescribe the criteria and schedule that will be used in discovery. The criteria and schedule in the procedures must include provisions for expediting the discovery of immediate conditions and for requiring that the discovery of any other anomaly needing response occur within 180 days of the date the ILI tool was retrieved or the date of the final observation.

(c) *Anomaly analysis.* Operators must follow the requirements in § 195.415 in determining predicted failure pressures, remaining life, and critical strain levels. As used in this section, the “failure pressure ratio” (FPR) is the predicted failure pressure divided by the MOP at the time when discovery occurs.

(d) *Schedule for evaluation and remediation.* An operator must establish a schedule for remediating or monitoring each anomaly in accordance with this paragraph.

(1) *Immediate conditions.* Remediate the following anomalies immediately upon discovery and maintain safety by reducing the operating pressure in accordance with paragraph

(e) of this section or shutting down the pipeline until the anomaly is repaired:

(i) Any of the following anomalies with an FPR of 1.1 and below:

(A) Metal loss, except when established using the plausible profiles method described in section 2.3(b) of ANSI/ASME B31G (incorporated by reference, *see* 195.3) use an FPR of 1.25 and below.

(B) Metal loss preferentially affecting a detected longitudinal seam formed by direct current, low-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0.

(C) Crack or crack-like anomaly.

(ii) Crack or crack-like anomaly with depth plus any metal loss greater than 70 percent of the nominal wall thickness or with depth that exceeds the maximum sizing capabilities of the ILI tool.

(iii) Metal loss greater than 80 percent of nominal wall thickness.

(iv) The following dents, unless an ECA demonstrates that critical strain levels are not exceeded and that geometric strain levels are less than 10 percent

(A) A dent that has any indication of cracking, gouging, stress riser, or metal loss (excluding corrosion metal loss that is both determined to not be caused by mechanical damage and the depth of metal loss does not exceed 10 percent of the nominal wall thickness).

(B) A dent located between the 8:00 o'clock and 4:00 o'clock positions (upper 2/3 of the pipe) (above the 4:00 and 8:00 o'clock positions) with a depth greater than six percent of the nominal pipe diameter.

(v) Any anomaly that requires immediate action in the judgment of the person designated by the operator to evaluate the assessment results.

(2) *Near-term conditions.* Remediate the following anomalies within 1 year of discovery:

(i) The following dents, unless an ECA demonstrates that critical strain levels are not exceeded or that geometric strain levels are less than 10 percent:

(A) A dent located between the 8:00 o'clock and 4:00 o'clock positions (upper 2/3 of the pipe) with a depth greater than two percent of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).

(B) A dent located between the 4:00 o'clock and 8:00 o'clock positions (lower 1/3 of the pipe) with a depth greater than six percent of the pipeline's diameter.

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

(ii) Any of the following anomalies with an FPR of 1.39 and below:

(A) Metal loss, including an area with general corrosion.

(B) Crack or crack-like anomaly.

(iii) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0.

(iv) Crack or crack-like anomaly with a depth plus any metal loss greater than 50 percent and less than or equal to 70 percent of the nominal wall thickness.

(v) Localized corrosion pitting with a depth greater than 50 percent of the nominal wall thickness.

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

(3) *Other Conditions*. If an anomaly that could impair the integrity of the pipeline does not require a response under the criteria in paragraphs (d)(1) and (2) of this section, schedule

response and remediation in accordance with §§ 195.401(b)(2) and 195.452(c)(8) as appropriate.

An operator must demonstrate that the remediation of the anomaly will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment. Any other anomaly, including all other dents managed with an ECA, must be recorded and monitored during subsequent assessments for any change that may require remediation. Appendix C of this part contains guidance concerning other conditions that an operator should evaluate.

(e) *Remediation and repair.* (1) An operator must use material property information meeting the requirements in § 195.415(e) in performing repairs.

(2) *Temporary pressure reduction.* Upon discovery of an immediate condition or when a near-term condition cannot be repaired within the time specified in paragraph (d)(2) of this section, an operator must temporarily reduce the operating pressure of the pipeline to a pressure at or below 80 percent of the operating pressure at the time of discovery or the predicted failure pressure times the design factor for the pipeline in § 195.106. The temporary pressure reduction must remain in place until the condition is repaired. An operator must submit a notification under § 195.18(a)–(b) if:

(i) an anomaly cannot be repaired within the time limits of this section and safety cannot be maintained through a temporary pressure reduction or other remediation action, or

(ii) a temporary pressure reduction exceeds 365 days.

26. In § 195.585, add paragraph (c) to read as follows:

§ 195.585 What must I do to correct corroded pipe?

* * * * *

(c) *Remaining Strength.* The strength of corroded pipe based on actual remaining wall thickness must be determined in accordance with § 195.415. These procedures apply to corroded

regions that do not penetrate the pipe wall, subject to the limitations set out in the respective procedures.

§ 195.587 [Removed]

27. Remove § 195.587.

§ 195.588 [Amended]

28. Amend § 195.588(c)(4)(i) by:

a. Removing the text “paragraph (b)(4)(ii)” and adding in its place the text “paragraph (c)(4)(ii),” and

b. Removing the text “using ASME/ANSI B31G or RSTRENG (incorporated by reference, *see* § 195.3)” and adding in its place the text “in accordance with § 195.415(b).”

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Keith Coyle,
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