Exhibit A

BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
WASHINGTON, D.C.

Pipeline Safety: Repair Criteria for Hazardous Liquid and Gas Transmission Pipelines	**Docket No. PHMSA-2025-0019**

SUPPLEMENTAL COMMENTS IN RESPONSE TO "REPAIR CRITERIA FOR HAZARDOUS LIQUID AND GAS TRANSMISSION PIPELINES" ADVANCE NOTICE OF PROPOSED RULEMAKING

FILED BY
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
AMERICAN GAS ASSOCIATION
GPA MIDSTREAMASSOCIATION

December 3, 2025

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I. INTRODUCTION

Pursuant to 49 CFR 190.317, the Interstate Natural Gas Association of America (INGAA)[1], American Gas Association (AGA)[2], and GPA Midstream Association (GPA Midstream)[3] (collectively, the Associations) submitted comments on the Pipeline and Hazardous Materials Safety Administration (PHMSA) May 2025 Advance Notice of Proposed Rulemaking (ANPRM).[4] The ANPRM requests stakeholders' input on potential opportunities to improve the cost-effectiveness of the current Part 192 repair requirements applicable to gas transmission pipelines. The Associations filed comments in response to the ANRPM on July 21, 2025, with limited information on Cost Benefit Analysis (CBA) associated with the proposed changes discussed in the comments.

The Associations submit these comments and calculations to support amending Part 192 regulations, allowing operators to implement performance-based integrity programs that include advanced technology, engineering evaluation methods, and data analytics.

II. EXECUTIVE SUMMARY

Pipeline safety is a top priority for the Associations and their members. While the Associations support strong pipeline safety requirements as they are a key aspect of facilitating the integrity and reliability of the nation's natural gas pipeline infrastructure, anomaly repair criteria are in significant need of reform. Current regulations compel operators to spend significant amounts of time and money investigating and repairing cracks, dents and other anomalies even though evidence and experience show they present a minimal safety threat. Incident data reported to PHMSA under 49 CFR 191.15, covering onshore gas transmission lines from 2010 through the

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[1] INGAA is a trade association that advocates regulatory and legislative positions of importance to the interstate natural gas pipeline industry. INGAA is comprised of 29 members, representing the vast majority of the U.S. interstate natural gas transmission pipeline companies. INGAA's members operate nearly 200,000 miles of pipelines.

[2] Founded in 1918, AGA represents more than 200 local energy companies committed to the safe and reliable delivery of clean natural gas to more than 180 million Americans. AGA is an advocate for natural gas utility companies and their customers and proves a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industrial associates. Today, natural gas meets more than one-third of the United States' energy needs.

[3] GPA Midstream is composed of approximately 50 corporate members that directly employ over 57,000 employees that are engaged in the gathering, transportation, processing, treating, storage and marketing of natural gas, natural gas liquids ("NGLs"), crude oil, and refined products, commonly referred to in the industry as "midstream activities." In 2024, GPA Midstream members operated more than 500,000 miles of pipelines, gathered nearly 91 Bcf/d of natural gas, and operated more than 340 natural gas processing facilities. Our members are an invisible link between raw natural gas and crude oil produced at the wellhead and the distribution of products to consumers for heating, electricity production, transportation, steelmaking, fertilizer production, plastics, high-tech devices, cosmetics, pharmaceuticals, and much more.

[4] 90 Fed. Reg. 21,715 (May 21, 2025).

first quarter of 2025[5], showed no incidents that were solely caused by dents, dents with metal loss, or dents intersecting a weld or seam.

The Associations recommend that PHMSA modernize the 49 CFR Part 192 regulations to recognize the advancement in technologies and analytical techniques that have occurred since the regulations were put in place. Modern inspection tools provide extensive information and data on pipeline conditions while advanced engineering assessment tools, such as Engineering Critical Assessment (ECA) and failure pressure calculations, characterize risks associated with specific defects. Together, these tools provide valuable information beyond what is found in the current regulations and deliver more information for operators to assess the condition of their pipeline systems. Obtaining and integrating these data sets allows operators to evaluate and more efficiently schedule necessary repairs, effectively committing resources to improve pipeline safety.

Updated industry standards account for improved repair methods; however, certain aspects of the current accepted analysis and repair requirements may limit the ability of operators to use ECAs, probabilistic modeling, and advanced in-line inspection (ILI) analytics. Further, current regulations do not account for improved methods for monitoring defect growth rates, predicting failure pressure, or ranking anomalies by actual risk.

Updating and modernizing the Part 192 regulations based on recent industry research, allowing for advanced tools and practices, will reduce unnecessary excavations, eliminate inconsistencies, update outdated requirements, and allow pipeline operators to focus time and resources on the most critical pipeline safety risks. PHMSA's adoption of the Associations' proposals would provide an opportunity for increasing the United States energy dominance by better allocating resources to improve pipeline safety, integrity, reliability, and expand infrastructure investment.

The ANPRM requested stakeholder input on, among other things, potential opportunities to improve the cost-effectiveness of the Part 192 repair requirements applicable to gas transmission pipelines. The Associations filed comments on July 21, 2025, providing limited CBA supporting information. These supplemental comments support the initial filing and provide calculations on the costs and benefits.

The Associations developed this framework to provide PHMSA with sufficient cost and benefit data to support necessary reforms, offering per-unit, aggregate, and programmatic information. The explanations and methodologies can provide PHMSA with accurate data estimates and impacts of modifying existing regulations as the Administration prepares a proposed rule and accompanying Preliminary Regulatory Impact Analysis (PRIA). Collectively, these analyses support PHMSA's mission to improve pipeline safety by providing a basis to modify existing

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[5] PHMSA Incident Data, https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data, Gas Transmission & Gathering Incident Data - January 2010 to present, Downloaded July 7, 2025.

regulations, allowing operators to reduce risk by allocating resources to improve pipeline safety, integrity, reliability, and expand infrastructure investment, rather than adhering to overly conservative, repair requirements. These approaches identify factors using currently available public data, including PHMSA Annual Report data[6], published Safety-Related Condition Reports (SRCRs)[7], Integrity Assurance Notification Data,[8] and Special Permit information[9]. Analyses of these datasets create a foundation and justification for sharing insights with PHMSA and are used throughout to support proposed regulatory reforms. In specific cost modeling, the data is combined with operator survey information.

The traditional cost-benefit analysis starts with the annual expenses that gas transmission operators will incur from 2027 through 2033 to comply with current repair criteria in Part 192, including the RIN 1[10] and 2[11] requirements that became effective in 2022. The traditional analysis compares the Associations' proposed repair criteria with current compliance activities. The difference represents the potential reduction in unnecessary and non-value-added expenditures.

To perform the analysis, the Associations surveyed 12 gas transmission operators, representing over 132,000 miles of onshore gas transmission mileage in the United States.[12] Operators provided data related to cracks, dents, corrosion, excavations, and repairs. Overall, this method captures the range of expected costs across different geographic locations, operator sizes, and systems. The analysis demonstrates the effectiveness of these measures based on established financial and operational metrics, enabling a comparison of costs and benefits.

The Associations offer the reliability approach as an alternative cost-benefit approach for this and future rulemakings. This is described in Appendix A. The calculations of the reliability method may be relatively new to PHMSA and to the U.S. pipeline industry; however, they have been applied to many other industries, including those with the concern of low likelihood/high consequence events. As described in Appendix A, the reliability-based method/analysis (R-CBA) relies on the use of more engineering, site-specific data that allows the method to apply less conservatism to achieve the same level of risk reduction. When comparing the results of the reliability method with the traditional approach, the delta is within 7.7%. This demonstrates that

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[6] https://portalpublic.phmsa.dot.gov/analytics/saw.dll?PortalPages&PortalPath=/shared/PDM%20Public%20Website/_portal/Public%20Reports&Page=GT%20IM%20Assess. Last accessed: Oct. 23, 2025.

[7] Leading Indicators - SRCR and Integrity Assurance (formerly IM) Notifications. Downloaded: Oct. 23, 2025.

[8] *Id*.

[9] https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-issued. Last accessed: Oct. 23, 2025.

[10] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," published on October 1, 2019.

[11] Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments, Final Rule, 87 Fed. Reg. 52,224, 52,248 (Aug. 24, 2022).

[12] The data was collected and the analysis was performed by a third-party to maintain confidentiality and anonymity and consistent with the Associations' respective anti-trust policies.

the reliability-based method should be considered a valid method because it provides results that are similar to the well-demonstrated approach that PHMSA and the industry have used for cost benefit analyses for many years. Further, this method is consistent with the risk based regulatory framework that PHMSA defined in the LNG ANPRM. The Associations believe PHMSA should consider using a reliability-based method for this and future rulemakings and are committed to providing PHMSA with support for using a reliability-based method throughout the rulemaking process.

The proposed reliability-based methodology is a "what-if" analyses. The proposed model uses real pipeline operator pipe attributes but creates corrosion and crack data by increasing the depth and length of each anomaly to evaluate the risk and create a risk profile. This approach identifies the cost required to achieve an accepted "as low as reasonably possible" risk profile compared to the current conservative prescriptive repair requirement that delivers less risk reduction. See Appendix A as a comparison analysis to the traditional cost benefit approach.

For both analyses, the Associations used the same operator-supplied dataset and excavation cost basis, reflecting average annual expenses for integrity excavation programs. The Associations' members provided their typical annual costs, including expenditures related to the gas pipeline rules under RINs 1 and 2, as well as low- and high-end costs per excavation. Because excavation costs vary depending on the depth, length, location, and complexity of the dig, the Associations used a quartile analysis to demonstrate sensitivities in the cost calculations by grouping data into lower, median, and upper quartiles, as well as showing the minimum and maximum values. This approach promotes transparency and reasonableness by reflecting the spread and variability of the cost range. This quartile analysis also aids in identifying and accounting for extreme outliers, leading to a more comprehensive and robust evaluation.

This cost benefit analysis further supports the safety and policy arguments that the Association made in its original comments.

Table 1: Summary of Cost and Benefits by Topic Area

Topic Area	Current Annual Compliance Cost	Traditional Method Benefit: Annual	Reliability Method Benefit: Annual (See Appendix A)
1a. Crack-like Excavation for reference only, based on 2024 values, non-annualized	$320,000,000 (Traditional)	$264,000,000 [1,3]	$245,000,000 [1,3]
	$355,000,000 (Performance-Based)[1]		
1b. Crack-like Feature 7-year Annualized (2027-2033)	$499,824,874	$413,283,676	$245,000,000 [2]
2. One Time Cost/Savings: Dent ECA § 192.18 Notifications Elimination	$962,948 (14 parent submissions)	$2,825,844 (42 parent future submissions avoided)	
3. Dents using ECA with Screening Method and no Finite Element Analysis (FEA)	$193,468,100	$145,101,075	
4. Discovery Occurs Only after Completed Engineering Evaluation	$190,906,418 (8,576 excavations)	$190,906,418 (8,576 future excavations avoided)	
5. Performance-based Approach for Corrosion and Dents, (See 1b for Cracking.)	$1,327,340,000[4]		$496,000,000
Total Annualized	$2,212,502,340[5]	$752,117,013	$741,000,000

1. The 2024 costs were calculated to illustrate the relative similarities between the traditional and the reliability methods.
2. $245M was used as an approximation of benefits for crack-like excavations but is not annualized over the 7-year period. We assume a similar year over year increase compared to the traditional analysis based on 2024 dollars.
3. There is a 7.7% savings difference between the Traditional Method and Reliability Method, which confirms validity of both methods
4. Performance-based costs include corrosion and dents only. The total performance based, with crack-like excavations, totaled $1.68B. The performance-based cost estimate is not annualized over the 7-year period but only reflects 2024 values.
5. This is the sum of annual compliance costs shown in 1b through 5.

Table 1 summarizes the total annualized current regulatory costs with a 3 percent discount rate and compares the findings to recalculations developed by the Associations based on proposed changes supported in the July 21 Association comments. The Associations utilized a 3 and 7 percent discount rate per OMB circular A-4 (2003).

Topic Areas

As explained in more detail below, the Associations used two CBA methodologies, and in some instances a combination of the two methods, for the recommended revisions to Part 192. The discussion below references tables that provide an overview of the most significant cost reductions that will be described in detail in specific topics in the Topic-by-Topic Cost Benefit Analysis section of this document.

The Associations evaluated crack-like excavations using both CBA methodologies. (Traditional is described below and Reliability-based is described in Appendix A.)

1. Crack-Like Excavations

The Associations' analysis of crack-like excavations addresses PHMSA's ANPRM questions III.A.1, III.A.3, and III.A.6 using both the traditional and reliability CBA methodologies. Specifically, this evaluation supports the following topics discussed:

- Required responses to crack-like anomalies in §§ 192.714 and 192.933 are overly prescriptive;
- Repairs required when the current crack depth plus any metal loss is greater than 50 percent;
- Immediate condition for cracking based on failure pressure;
- The toughness values in §§ 192.712(d)(3) and 192.712(e)(2)(i) should be revised using actual data; and
- Tool tolerance and predicted failure pressure.

Table 2 summarizes the baseline industry impact by estimating excavation costs under low, medium, and high-cost scenarios. As supported by data from the PHMSA Annual Report and the average increases in mileage inspected for cracks for the past three years, the Associations assume that pipeline operators will increase the mileage assessed for cracks each year at an average rate of 19 percent. To provide a realistic outlook, the projected 2027 mileage is based on 14,567 crack tool mileage (reported in 2024 without escalation), with the annual increase applied through 2033. Based on the analysis, the Associations estimate that the current impact on the industry over the seven years will result in over 22,000 crack-like excavations and cost industry over $4 billion.

To understand the impact of the Associations' proposal, operator survey data was analyzed to determine the percentage of excavations avoided as unnecessary. Table 4 summarizes these reductions by applying the percentage reductions to the number of future crack-like excavations. Collectively, these reductions result in a 61 percent decrease in the number of crack-like excavations. Table 5 calculates the benefits of eliminating unnecessary excavations, estimated to be $3.3 billion over a seven-year period.

The Associations evaluated the topic areas below using the traditional methodology only:

2. Dent ECA § 192.18 Notifications Elimination

The Associations analyzed the time from submission of a § 192.18 notification to resolution. Separately, the Associations analyzed the time to resolve ECA dent notifications under § 192.18. Between 2023 and 2025, operators submitted fourteen § 192.18 notifications for ECA dents.[13] As shown in Table 8, the Associations found the ECA Dent submissions take an average of over 400 days to resolve—a significantly longer time than the anticipated 90 days. There is no requirement for PHMSA to resolve these notifications within any timeframe. The Associations estimate that operators and PHMSA staff—combined—spent over 8,400 hours on dent ECA notifications, amounting to more than $0.96 million in costs.

The significant delays involved should persuade PHMSA to exclude ECA Dents from the § 192.18 notification process—or improve the process—as the current process discourages the use of advanced technologies and methods and delay compliance activities. This topic answers PHMSA's ANPRM Questions III.A.1, III.C.1, and III.C.2.

3. Acceptance of Other Analytical or Empirical Models to Evaluate Strain in Lieu of FEA

The Associations analyzed the current regulatory environment using PHMSA Annual Report Data Part F to estimate future dent tool miles. The Associations assumed that dent tool mileage will continue to grow at an average rate of 5 percent year over year. Based on this analysis, the Associations estimate that over seven years, industry will be required to perform over 8,600 dent excavations, with costs of $1.15 billion. Table 14 summarizes these reductions by applying a 75 percent decrease to the number of future dent excavations, achieved through incorporating the Association proposal to allow a dent ECA procedure that allows the use of other analytical techniques for dent evaluation in lieu of FEA, as allowed by § 192.712(c)(9). The Associations estimate that this results in a net benefit of $1.1 billion over seven years. This cost savings analysis supports PHMSA's ANPRM Question III.A.1.

4. Discovery Based on Engineering Evaluation

As outlined in the Associations' July 21 comments, clarifying the discovery date as being after operators complete engineering analyses ensures that anomalies are

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[13] Leading Indicators - SRCR and Integrity Assurance (formerly IM) Notifications. Downloaded: Oct. 23, 2025.

accurately characterized and conditions meet repair criteria. Applying proper engineering analysis to all identified conditions decreases unnecessary excavations when response conditions can be avoided based on preliminary report data. Table 17 summarizes the benefit of clarifying that the discovery date is when engineering analyses are completed, which results in a benefit of $1.5 billion. See PHMSA's ANPRM Question III.A.4.

The Associations evaluated the topic areas below using an alternative reliability-based methodology only. See Appendix A:

5. Performance-Based Approach for Corrosion, Dents, and Cracking

The Associations proposed using a risk-based approach in place of the prescriptive requirements of 49 CFR Part 192.714 and 192.933. This answers PHMSA's ANPRM Questions III.A.1, III.A.3, III.A.6, III.A.10, and III.C.4.

As described above, this analysis focused on the areas with the most significant cost savings opportunities. The Associations will provide cost benefit data on the topics below as the rulemaking process continues.

- . Authorize Eddy Current Technology to eliminate redundant inspections. See PHMSA's ANPRM Question III.A.1.
- Clarify that operators have up to 10 years to assess newly activated threats. See PHMSA's ANPRM Question III.A.5.
- PHMSA Should Clarify or Define the Meaning of "Susceptible." See PHMSA's ANPRM Question III.A.5.
- PHMSA Should Clarify or Define Excavation Requirements for Internal Corrosion Direct Assessments. See PHMSA's ANPRM Question III.A.5.
- PHMSA should revise regulations to Avoid Discouraging Use of ECA. See PHMSA's ANPRM Questions III.C.1, III.C.2, III.C.3.
- ECA Re-Assessment Intervals Should be Eliminated. PHMSA's ANPRM Question III.C.5.
- Associations request that PHMSA preserve and enhance flexibility in repair method selection and establish a pathway for innovative technologies and techniques. See PHMSA's ANPRM Questions III.A.3 and III.A.7.

III. SUMMARY OF COST METHODOLOGY

The Associations estimated costs based on the average expenses of operators' integrity excavation programs. As described earlier, the Associations surveyed 12 gas transmission operators, who submitted their average annual costs, including expenditures related to compliance with gas pipeline repair rules under RINs 1 and 2. Operators also provided low- and high-end costs per excavation. However, as PHMSA is aware, excavation costs vary depending on the depth, diameter, length, location, and complexity of the dig. To address these differences, the Associations used a quartile analysis to demonstrate sensitivities in the cost calculations by grouping data into lower, median, and upper quartiles, as well as showing the minimum and maximum values. This approach promotes transparency and reasonableness by reflecting the spread and variability of the cost range. This also aids in identifying and accounting for extreme outliers, leading to a more comprehensive and robust evaluation.

Below describes the factors that the Associations considered in establishing the quartile approach, based on the operator provided dataset (low and high costs), to more accurately demonstrate the range of costs.

The **low end** of the excavation costs could be based on factors such as:

- The operator has immediate access to the right of way with minimal landowner impacts;
- Excavations may be only 1,000 feet apart and would reduce mobilization and demobilization costs as resources and equipment could be shared between both excavation sites; or
- Internal resources may be able to conduct the excavations and would typically yield lower excavation costs than using a contractor.

The Associations assumed that most excavation costs would be the **medium cost**, which would represent a typical access excavation using contractor resources and a three-foot deep pipeline.

The **high end** of the excavation costs would be based on the factors such as:

- The anomaly requires horizontal directional drilling or a more specialized repair process, such as for segments located underneath or near rivers, railroad rights of way, or steep terrain, or in densely populated urban areas, or requiring specialized or high-cost contractor support;
- An excavation site requires a large quantity of timber matting for access;
- Excavations beyond typical depth that might require an engineered excavation with shoring to ensure stable and safe excavations and pipeline evaluation;
- Repairs on steep terrain that require additional geotechnical review, shoring, and other support to limit earth movement once soils are restored to their original contour;
- Excavations that require greater payment for landowner impacts, (e.g., tree cutting for access, temporary bridge installation for creek crossing for access and associated cleanup costs, crop damages, payments for additional work area); or
- States that have higher landowner access costs for temporary laydown or payment for property impacts, labor costs, permitting costs, or a combination of these that can significantly increase costs.

Table 2 summarizes the annual excavation program costs for 12 operators. Examining the costs of one low-end and one high-end excavation shows a range from $18,000 to $10 million, respectively. The Associations acknowledge that some excavations can incur significant costs, but such cases are less common. Overall, it is reasonable to estimate that most excavations would fall between the average low-end and high-end bounds: average quartile 1 ($87,688), average quartile 2 ($180,000), and average quartile 3 ($421,688). The Associations used excavation costs in both the traditional and reliability calculations.

Table 2: Excavation Costs Derived from Data of 2,900 Excavations Across 12 Operators

	Min	Max	Q_1 (lower bound at the 25th percentile)	Q_2 (middle bound at the 50th percentile)	Q_3 (upper bound at the 75th percentile)
Low End per Excavation Cost[2]	$18,022[1]	$210,195	$37,875	$47,500	$106,875
Average High and Low End[5]			$87,688	$180,000	$421,688
High End per Excavation Cost[4]	$80,000	$10,000,000[3]	$137,500	$312,500	$736,500

1. Based on an ideal scenario, such as easy mobilization, immediate access to roads, flat excavation, no additional resources needed, minimal crew.
2. See low-cost examples above.
3. Based on a difficult scenario, such as horizontal directional drilling (HDD) under a waterway on a pipe that cannot be taken out of service due to customer requirements.
4. See high-end excavation costs above.
5. The Associations used the average costs of the low-end and high-end excavation value.

A. Traditional Methodology

This document includes a comprehensive framework for assessing repair criteria using a traditional approach. The Associations developed this framework to provide PHMSA with sufficient cost and benefit data to support industry positions, offering per-unit, aggregate, and programmatic information. Collectively, these supplemental comments and accompanying analyses support PHMSA's mission to improve pipeline safety by providing a basis for modifying existing regulations. allowing operators to reduce risk by prioritizing higher risk anomalies rather than devoting resources based on overly conservative repair requirements.

The traditional approach identifies data using currently available public data, including 2024 PHMSA Annual Report data[14], published Safety-Related Condition Reports[15], Integrity Assurance Notification Data, and Special Permit information[16]. Analyzing these datasets creates a foundation and justification for sharing insights with PHMSA and is used throughout to

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[14] https://portalpublic.phmsa.dot.gov/analytics/saw.dll?PortalPages&PortalPath=/shared/PDM%20Publi… downloaded on October 23, 2025

[15] https://www.phmsa.dot.gov/data-and-statistics/pipeline/leading-indicators-srcr-and-im-notifications downloaded on October 23, 2025

[16] https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-issued accessed on October 23, 2025

support industry positions. In specific cost modeling, the data is combined with operator survey information.

The traditional cost approach estimates the annual expenses that gas transmission operators incur to meet and comply with repair criteria in Part 192, including the RIN 1 and 2 requirements. It then assesses the removal of outdated and ineffective, non-value-added compliance activities. Eliminating such requirements contributes to the United States' energy dominance by providing opportunities to more efficiently allocate resources to pipeline safety, integrity, reliability, and infrastructure investment. This efficiency helps keep energy costs lower, fostering business growth and development while reducing residential energy expenses.

To perform the analysis, the Associations surveyed 12 gas transmission operators, representing over 132,000 miles of gas transmission mileage in the United States. Operators provided various annual average data related to cracks, dents, corrosion, excavations, and repairs. Overall, this method captures the range of expected costs across different geographic locations, operator sizes, and systems. The analysis demonstrates the effectiveness of these measures based on established financial and operational metrics, enabling a comparison of costs and benefits.

IV. TOPIC-BY-TOPIC COST BENEFIT ANALYSIS

A. Required Responses to Crack-like Anomalies in §§ 192.714 and 192.933 are Overly Prescriptive

Engineering Analysis on Benign Manufacturing-related Crack-Like Anomalies

Currently, gas transmission pipeline operators allocate significant resources to excavations to investigate crack-like anomalies. Sections 192.714(d)(1)(v)(A) and 192.933(d)(1)(v)(A) do not allow an operator to perform an engineering analysis to discern between benign stable manufacturing-related crack-like anomalies and time-dependent crack-like anomalies that may be associated with more serious cracking conditions. As a result, operators often must perform unnecessary excavations that can cause service disruptions and potentially have adverse impacts. Many of these excavations are unnecessary and do not improve pipeline safety. The Associations support reducing the number of these unnecessary excavations by applying engineering analysis to discern crack-like anomalies defined as "stable anomalies" that occur during the manufacturing process and pass a pressure test. As discussed in the Associations comments on the Repair Criteria ANPRM, these crack-like features are often time-independent manufacturing-related anomalies (e.g., hook cracks, lack of fusion, and laminations) that have existed in the pipeline since construction, and they do not pose a real threat to pipeline integrity. Some of these features have survived mill testing and post-construction pressure testing. According to § 192.917(e)(3), within an HCA, an operator can consider this type of threat as a stable manufacturing defect if the pipeline has been subjected to a pressure test to at least 1.25 times maximum allowable operating pressure (MAOP), has not experienced an incident since that pressure test, the MAOP has not increased, the stresses leading to cyclic fatigue have not increased, and no interacting threats destabilized a stable manufacturing defect, per § 192.917(c)(2).

1.1 x MAOP with 70% Depth Threshold

The Associations noted in their ANPRM comments that INGAA asserted throughout the 2022 Gas Transmission Repair rulemaking process and ensuing litigation that 1.1 x MAOP was a sufficient and a technically supported standard.[17] The Associations remain steadfast in their support of 1.1 x MAOP for cracking and in line with the current recommendations in API RP 1176, Assessment and Management of Cracking in Pipelines, and specifically, section 11.7.2, Immediate Response Conditions, which is the same section that cites the 70% depth threshold.[18]

Charpy V-Notch (CVN)

Lastly, as noted in the original comments, the Associations recommend removing the prescriptive CVN toughness values set forth in § 192.712(e)(2) and request that PHMSA allow operators the option to use the more appropriate CVN and toughness values reflected in the PRCI report entitled PR276-223814-R01 Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values or use the processes defined in PR-276-223814 Pragmatic Application of MegaRule RIN 1 - 192.712 Toughness Values L1 Procedures or similar processes when more information is known about the material. These reports provide comprehensive guidance based on established science and a large dataset of CVN values from several pipeline operators covering various vintages, manufacturing methods, and pipe types. Operators should be able to utilize more pipe specific values from industry databases or newer research to assist in obtaining values that meet the requirements of § 192.712(e)(2)(i)(A). Additionally, reliance on CVN values ignores more accurate fracture toughness methods (e.g., ASTM E1820) and fails to account for quasi-static loading conditions, making requirements unnecessarily restrictive.

1. Traditional Cost Benefit Methodology: Cracks

To project current costs related to crack-like excavations, the Associations analyzed the existing regulatory environment. This analysis estimates the future number of crack tool miles inspected starting in 2027, assuming a final NPRM is issued in 2026, and a final rule takes effect in 2027. Therefore, the analysis considers a baseline scenario where PHMSA chooses not to make any changes to Part 192 that impact crack-like excavations.

Table 3 summarizes the baseline industry impact by estimating the number of future excavations under low-, medium-, and high-cost scenarios. The Associations assume that crack-tool mileage assessments will continue to grow at an average rate of 19 percent, supported by data from the PHMSA Annual Report and the averages for the past three years. To provide a realistic outlook,

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[17] *See INGAA v. PHMSA*, 114 F.4th 744, 751-52 (D.C. Cir. 2024).

[18] See the Associations comments in response to the Repair Criteria ANPRM for a full discussion on this 70% depth threshold.

the 2027 mileage is based on 14,567 crack tool mileage (reported in 2024 without escalation), with the annual increase applied through 2033. The year-over-year increase in mileage is supported by recent changes in RINs 1 and 2, which approved the use of EMAT technology, requires reconfirmation of MAOP, and mandates assessing for threats of § 192.710 segments. Based on the analysis, the Associations estimate that the impact on the industry over the seven years will result in over 22,000 crack-like excavations, collectively costing operators over $4 billion.

Table 3: Baseline Crack Excavations

	Crack Tool Miles Inspected[1]	Current Crack-Like Excavations[2]	Low Excavation Cost ($87,688) (x) Excavations[3,7,]	Mid Excavation Cost ($180k) (x) Excavations[4,7,]	High Excavation Cost ($421,688) (x) Excavations[5,7,]	Total Cost[6]
2027	14,567	1,815	$47,746,116	$196,020,000	$76,536,372	$320,302,488
2028	17,335	2,160	$56,819,387	$233,269,995	$91,080,701	$381,170,083
2029	20,628	2,570	$67,615,070	$277,591,294	$108,386,035	$453,592,399
2030	24,548	3,059	$80,461,934	$330,333,639	$128,979,381	$539,774,955
2031	29,212	3,640	$95,749,701	$393,097,031	$153,485,464	$642,332,196
2032	34,762	4,331	$113,942,144	$467,785,467	$182,647,702	$764,375,313
2033	41,367	5,154	$135,591,152	$556,664,706	$217,350,765	$909,606,623
Total	182,418	22,729	$597,926,773	$2,454,767,337	$958,468,452	$4,011,162,562
3% Discount 7-Year Total						$3,498,774,116
7% Discount 7-Year Total						$2,948,101,886
3% Discount Annual						$499,824,874
7% Discount Annual						$421,157,412

1. Based on an average 19% annual increase in crack tool inspections (based on average % increase using PHMSA Annual Report Data: 14,567 in 2024, 11,812 in 2023, 10,036 in 2022)
2. Assumes a 0.1246 excavations per mile based on operator survey: annual crack excavations/crack tool inspections miles (886 excavations/7,110 inspection miles)
3. Based on 30% of excavations at the low-end excavation cost
4. Based on 60% of excavations at the middle excavation cost
5. Based on 10% of excavations at the high-end excavation cost
6. Total excavation cost of low, med, and high excavations
7. Excavation costs do not include CPI related escalation, but Associations anticipate higher escalation rates than CPI

To understand the impact of the Associations' proposal, operator survey data was analyzed to determine the percentage reductions in excavations that could be expected if PHMSA implemented the proposal. Table 4 summarizes these reductions by applying the percentage reductions to the number of future crack-like excavations. To prevent overestimating the reduction or double counting, the analysis first accounts for the reduction in total excavations minus "Reduction A," then applies "Reduction B" to the remaining excavations, followed by the application of "Reduction C" and "Reduction D."

Table 4: Reduction of Excavations Based on the Association Crack-Like Proposal

	Current Immediate Crack-Like Excavations	A. Excavations of crack-like manufacturing excavations with ECA[1]	B. Excavations from crack-like indications with metal loss between 50-70%[2]	C. Excavations with crack-like indication with failure pressure 1.1-1.25 MAOP[3]	D. Excavations with conservative CVN thresholds[4]	TOTAL Immediate Excavation Reductions (A+B+C+D)
2027	1,815	309	648	120	37	1,113
2028	2,160	367	771	143	44	1,325
2029	2,570	437	917	170	52	1,577
2030	3,059	520	1,092	203	62	1,876
2031	3,640	619	1,299	241	74	2,233
2032	4,331	736	1,546	287	88	2,657
2033	5,154	876	1,840	341	105	3,162
Total	22,749	3,864	8,112	1,505	462	13,944

1. Reductions are based on a 17% reduction calculated from operator survey data, which is applied to the number of crack-like excavations from Table 3.
2. Reductions are calculated from the remaining excavations (less A), with 43% reductions based on operator survey data of those excavations that are due to crack-like indications with metal loss between 50-70%
3. Reductions are calculated from the remaining excavations (less A and B) with 14% reductions based on operator survey data
4. Reductions are calculated from the remaining excavations (less A, B, C), with an assumed 5% impact on excavations (operators report that 10% currently of excavations are due to CVN requirements)

As shown, implementing the Associations' proposed changes to reclassify specific criteria and thresholds results in a 61 percent decrease in immediate crack-like excavations without a significant decrease in pipeline safety. This will enable industry to more effectively prioritize and allocate resources to threats commensurate with their level of risk. The industry views this as a safety advantage. This could be achieved by directing resources toward pipeline safety, integrity, reliability, and infrastructure investment. The Associations argue that only 39 percent of current immediate crack-like excavations should be excavated and evaluated for repair. In contrast, the remaining 61 percent should be deferred or eliminated based on thorough engineering analyses and assessments. To evaluate the overall benefit of reducing unnecessary excavations, the Associations calculated excavation costs using both low and high estimates.

Table 5 highlights the benefits, estimated to be $3.3 billion over a seven-year period. Providing operators with flexibility in how anomalies are reviewed enables them to improve the efficiency of their operations and invest their resources appropriately.

Table 5: Reduction of Crack-Like Excavation Benefits

	Current Crack-Like Excavations[2]	TOTAL Reductions (A+B+C+D)	Low Excavation Benefit[1, 5]	Medium Excavation Benefit[2, 5]	High Excavation Benefit[3, 5]	Total Excavation Benefit[4, 5]
2027	1,815	1,113	$97,637,194	$120,253,820	$46,953,327	$264,844,342
2028	2,160	1,325	$116,191,347	$143,105,846	$55,875,943	$315,173,136
2029	2,570	1,577	$138,267,703	$170,295,957	$66,492,372	$375,056,032
2030	3,059	1,876	$164,538,566	$202,652,189	$79,125,923	$446,316,678
2031	3,640	2,233	$195,800,894	$241,156,105	$94,159,848	$531,116,847
2032	4,331	2,657	$233,003,064	$286,975,765	$112,050,219	$632,029,048
2033	5,154	3,162	$277,273,646	$341,501,161	$133,339,761	$752,114,567
Total	22,749	13,944	$1,222,715,007	$1,505,944,038	$587,998,638	$3,316,657,683
3% Discount over 7-Year Total						$2,892,985,730
7% Discount over 7-Year Total						$2,437,658,565
3% Discount Annual						$413,283,676
7% Discount Annual						$348,236,938

1. Based on 30% of reductions at the low-end excavation cost
2. Based on 60% of reductions at the middle excavation cost
3. Based on 10% of reductions at the high-end excavation cost
4. Total Excavation Benefit includes low, medium and high benefits
5. Total excavation benefits do not include Consumer Price Index (CPI) related escalation, but Associations anticipate higher escalation rates than CPI.

Table 6 summarizes the total annualized incremental costs calculated by the Associations and compares these findings to the calculations in Table 3 and Table 5. The new total compliance cost is the difference between the current prescriptive regulatory environment and the changes proposed by the Associations.

Table 6: Comparison of Crack-Like Excavation

Annual Discount	Current Baseline Prescriptive Crack Excavation Requirements	Associations Proposed Crack Excavation Benefits	New Total Compliance Cost
3% Annual	$499,824,874	$413,283,676	$86,541,198
7% Annual	$421,157,412	$348,236,938	$72,920,475

B. Reduction in the Use of § 192.18 Notifications

Operators should be able to implement new technologies and processes based on sound engineering justification. The current PHMSA § 192.18 notification process hampers operators' ability to deploy these innovative technologies and methods, as PHMSA often delays the use of these technologies and methods beyond 91 days following the submission of the advance notification. Operators should be able to implement new technologies or processes as they are already required to maintain thorough documentation of their procedures and processes and are required to provide sound engineering technical justifications. Operators’ procedures, processes, and evaluations are subject to audit and enforcement if PHMSA finds that they do not comply with the regulations. To alleviate the § 192.18 bottleneck, the Associations recommend that PHMSA provide for conditional or performance-based acceptance of new technologies to enable their implementation while maintaining safety oversight. Further, the Associations request that PHMSA implement a timeline by which the Administration must respond or put limitations on reasons it can object to a notification.

Based on a review of the PHMSA Gas Transmission Integrity Assurance Notification database, the following notifications have been submitted by year and their status. However, when analyzing the database, it was also necessary to examine the data by operator notification numbers to determine when operators submitted the same notification requests with different operator IDs.

Since 2020, operators have submitted a total of 372 Integrity Assurance Notifications from 206 parent company submissions (extracted from “Integrity Assurance Notif”). This indicates that some parent companies have submitted multiple notifications for the same issue. For example, 18 submissions were made for the same Mechanical Dent ECA notification, which would be considered a single overall submission.

Table 7: PHMSA Gas Transmission Integrity Assurance Notification by Status

Year	Objection Resolved Submission	Resolved Submissions	Under Review Submissions	Total Submissions	Total Parent Operator Submissions[1]	# of Parent Operator Submissions Over 90 Days (including UR)[2]
2020	5	32	12	49	25	12
2021	2	32	7	41	29	17
2022		17	12	29	24	24
2023	1	78	7	86	40	24
2024	13	92	16	121	51	28
2025		24	22	46	37	2[3]
Total	21	275	76	372	206	107

1. When multiple submissions were submitted for the same notification by the same parent company with different Operator IDs, these submissions are considered to be one submission.
2. Includes those notifications under review.
3. 2025 excludes the number of submissions under review.

Based on analysis of the database, the Associations find that approximately 52% of parent operator submissions result in resolutions after the 90-day threshold. This finding suggests that the current § 192.18 notification process is not achieving the desired level of efficiency. Furthermore, when specifically examining the ECA Mechanical Damage Evaluation numbers, the average number of days to resolution exceeds a year (nearly 400 days), which is significant. When operators were surveyed, only 4 operators responded and the effect of these time limitations resulted in 74 unnecessary excavations that required digging to comply with the 90-

day limit, resulting in 39 unnecessary repairs while operators waited for a response or resolution from PHMSA.

To reiterate this point, the Associations refer to Table 8 below, which shows the average number of days exceeding 91 days by notification type, excluding the under-review period.

Table 8: 2020-2025 PHMSA Gas Transmission Integrity Assurance Notification by Response Days

	Objections Resolved	Resolved Without Objections	Under Review	Total Average of Response Days
METAL LOSS LESS CONSERVATIVE		12		718
ECA MECHANICAL DAMAGE EVALUATION	11	38	15	404
RMV INSTALLATION DELAY NEW		1		324
PRESSURE	1	9	4	267
MAOP RECONFIRMATION OTHER ECA TECHNOLOGY		3		246
ASSUMED TOUGHNESS		27	1	203
TECHNOLOGY		7		164
ILI RESULTS EXTENSION		2	1	154
PRESSURE OUTSIDE HCA		1	1	109
REASSESSMENT INTERVAL BELOW 30% SMYS		4	4	99
MAOP RECONFIRMATION METHOD 6		32	8	94
TOTAL	12	136	34	

The Associations recommend that PHMSA allow for conditional or performance-based acceptance of new technologies and methods. Doing so would save operator and PHMSA personnel time and resources by avoiding unnecessary hours developing and responding to questions, as well as planning and completing unnecessary excavations and repairs.

Another consideration is the amount of operator time needed to submit and respond to PHMSA notification questions or to plan and complete unnecessary excavations. According to operator feedback, they spend from 80 to 2,000 hours per notification unnecessarily planning an excavation to meet a conservative prescriptive deadline due to the extremely long PHMSA response times. Table 9 shows the activities and personnel involved in submitting a dent ECA notification, which took approximately 400 hours of staff time. For this cost benefit analysis, the Associations used the publicly available data from the U.S. Bureau of Labor Statistics for the Pipeline Transportation of Natural Gas Industry.[19,20] However, the Associations find that these labor costs are understated for the experience level of the engineers that its members would employ to submit these notifications. Additionally, these costs do not include additional employee benefits.

Table 9: Hours Associated with Handling an ECA Mechanical Damage Evaluation Notification

Activity	Labor Category	Labor Cost ($/hr.)	Hours	Cost per Activity
Various engineers participate in discussions with a service provider, internal meetings, procedure creation and review process, and arrange meetings for executive and attorney review of proposed submission/PHMSA response.	Engineers (Code 17-2000)	$57.42	306	$17,571
Management Review: Manager and Director review of § 192.18 Notification and supporting materials prior to PHMSA submission. This group assists in reviewing draft responses to PHMSA's questions and participates in any meetings or calls.	Top Executives (Code 11-1000)	$78.68	50	$3,934
GIS or other records may be necessary to demonstrate examples of remediation, new technologies being applied, locations of planned remediation, generate engineering design drawings, or other support functions to ensure successful review of § 192.18 notification	Drafters, Engineering, Technicians, Mapping Tech (Code 17-3000	$42.71	2	$85.42
Includes Supply Chain Management Support, Purchase Order Creation, invoice reconciliation for service provider to respond and assist in building procedures, supporting the use of new technologies.	Other Office and Administrative Support Workers (Code 43-9000)	$26.37	2	$52.74

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[19] Pipeline Transportation of Natural Gas - May 2023 OEWS Industry-Specific Occupational Employment and Wage Estimates

[20] https://www.bls.gov/bls/wages.htm

Assists in the response submittal, ensuring clear communications, builds presentations for discussion with PHMSA and internal/external stakeholders.	Media and Communication Workers (Code 27-3000)	$53.97	10	$540
An attorney typically reviews submittals, possibly procedures, reviews contractual language for new vendors or service providers to use new technologies and supports as needed for documentation review.	Legal Occupations (Code 23-0000)	$121.56	30	$3,647
Total			400	$25,830

In 2024, parent company operators submitted 51 notifications. Of these, 3 had objections, 39 were resolved, and nine are still under review. To illustrate the inefficiency of the process, Table 10 presents the number of parent company ECA Dent submissions (a subset of the total notifications) by status along with the hours associated with each. Operator hours are determined based on the complexity of the submission, as outlined in Table 9, with those under lengthy review or with objections requiring more time. The Associations assume that PHMSA would spend half the amount of time reviewing or commenting on a notification. According to these assumptions, between 2023 and 2025, operators and PHMSA staff spent over 8,400 unnecessary hours on notifications, even though operators' procedures, processes, and evaluations are already subject to audit and enforcement if PHMSA identifies non-compliance with regulations or operators not following their procedures.

Table 10: Operator and PHMSA Hours Associated with ECA Notifications

Notification Type	Notification Status	Parent Company Submissions	Operator Hours	PHMSA Hours	Total Hours
2023	3 resolved 2 under review	5	400	200	3,000
2024	2 resolved 1 objection resolved 3 under review	6	400	200	3,600
2025	1 resolved 2 under review	3	400	200	1,800
Total		14		600	8,400

Conversely, since these hours are distributed among multiple employees—such as engineers, directors, field technicians, project management specialists, and office support staff—they must be integrated into their daily work schedules.

To calculate the cost of submitting and responding to ECA notifications, the number of submissions was multiplied by the operator unit cost, and then the PHMSA cost was added based on the number of hours multiplied by the engineer's hourly rate of $57.42.

Table 16: Costs Associated with ECA Mechanical Damage Evaluation Notification

Year	ECA Submissions	Cost Operator per notification[1]	External Vendor Support	Operator Cost	PHMSA Cost ($57.42/hr.)[2]	Total
2023	5	$25,830	$7,000	$164,150	$172,260	$343,410
2024	6	$25,830	$7,000	$196,980	$206,712	$410,692
2025	3	$25,830	$7,000	$98,490	$103,356	$208,846
Total	14			$459,620	$482,328	$962,948

1. Labor costs are based on Table 14
2. PHMSA hours are based on Table 15 at a rate of $57.42 per hour

The Associations support an engineering evaluation process for dents to determine if a dent is injurious to the pipeline instead of the current § 192.18 PHMSA notification process. As supported in the original comments, analyzing incidents during 2010 through 1Q of 2025 resulted in no incidents caused by dents:

- No incidents that were solely a result of plain dents
- No incidents attributable to dents with metal loss
- No incidents attributable to dents intersecting a weld/seam (girth and long)

Additionally, as noted from the original comments, the Associations evaluated incidents involving dents with cracking and determined that they posed a lower risk. The Associations support including engineering analyses when evaluating dents to include site specific conditions in the evaluation process. Together, industry and PHMSA have invested significant time and resources in developing a reliable ECA dent process that presents very low risk from an incident perspective.

The Associations assume that the number of dent ECA submissions will more than triple by 2027 due to recent dent ECA approvals by PHMSA and indications of future submissions by the Associations' members. Table 17 summarizes the cost impacts and resources for 42 submissions anticipated in 2027.

Table 17: Submissions on Dent ECA in Annual Submissions

Year	ECA Submissions	Cost per submission	Vendor Cost	Operator Cost	PHMSA Cost	Total
2027	42	$25,830	$7,000	$1,378,860	$1,446,984	$2,825,844

C. Acceptance of Other Analytical or Empirical Models to Evaluate Strain in Lieu of FEA

The Associations suggest that PHMSA allow the inclusion of "other technology" or "other analytical methods" as suitable options for a dent ECA, without requiring a FEA to evaluate strain levels and fatigue life. According to surveyed operators, 64 percent of them have an ECA dent process that involves FEA. Of these, three operators requested exemptions from using FEA; however, no companies have been approved to use alternative technologies or analytical methods even though 49 CFR 192.712(c)(9) allows for other methods to be used.

Based on the Associations' member data, the operators estimated that if they could utilize the ECA dent process without an FEA, they could eliminate between 50 and 95 percent of dent excavations.

The Associations used PHMSA Annual Report Data Part F to estimate future dent tool miles. We assumed that dent tool mileage will continue to grow at an average rate of 5 percent. A similar approach was used, starting with the 33,284 miles reported in 2024 without escalation in 2027, and applying the annual increase through 2033. Based on this analysis, the Associations estimate that over seven years, the industry will see over 8,600 dent excavations, costing approximately $1.5 billion for a threat that has historically posed a low risk.

Table 18: Baseline Dent Excavations

	Dent Tool Miles Inspected[1]	Current Dent Excavations[2]	Low Excavation Cost ($87,688) (x) Excavations[3]	Mid Excavation Cost ($180k) (x) Excavations[4]	High Excavation Cost ($421,688) (x) Excavations[5]	Total Excavation Cost[6]
2027	33,284	1,065	$28,018,631	$115,029,504	$44,913,483	$187,961,618
2028	34,948	1,118	$29,419,563	$120,780,979	$47,159,157	$197,359,699
2029	36,696	1,174	$30,890,541	$126,820,028	$49,517,115	$207,227,684
2030	38,530	1,233	$32,435,068	$133,161,030	$51,992,971	$217,589,068
2031	40,457	1,295	$34,056,821	$139,819,081	$54,592,619	$228,468,521
2032	42,480	1,359	$35,759,662	$146,810,035	$57,322,250	$239,891,947
2033	44,604	1,427	$37,547,645	$154,150,537	$60,188,363	$251,886,545
Total	270,999	8,672	$228,127,930	$936,571,194	$365,685,957	$1,530,385,081
3% Discount 7-Year Total						$1,354,276,701
7% Discount 7-Year Total						$1,162,811,156
3% Discount Annual						$193,468,100
7% Discount Annual						$166,115,879

1. Based on an average 5% increase in dent tool inspections annually (based on average % increase using PHMSA Annual Report Data: 33,284 in 2024, 35,147 in 2023, 33,262 in 2022).
2. Assumes 0.032 excavations per mile based on operator survey: annual dent excavations/dent tool inspections miles (operator input provided the following - 638 excavations/20,046 inspection miles).
3. Based on 30% of excavations at the low-end excavation cost.
4. Based on 60% of excavations at the middle excavation cost.
5. Based on 10% of excavations at the high-end excavation cost.
6. Total cost of low, med, high excavation costs.

To understand the impact of eliminating between 50 and 95 percent of unnecessary dent excavations, the Associations conservatively estimated cost savings. Table 14 summarizes these savings by evaluating a 75 percent decrease in dent excavations, achieved through incorporating a dent ECA procedure that allows the use of other analytical techniques, in lieu of FEA. The Associations estimate that this results in a net benefit of $1.1 billion over seven years.

Table 14: Reduction of Excavations Based on the Application of ECA That Allows the Use of Other Analytical Techniques in Lieu of an FEA, as allowed by § 192.712(c)(9)

	Current Dent Excavations	Reduction of Dent Excavations (ECA wo FEA)[1]	Savings of Excavations (Low)[2]	Savings of Excavations (Med)[3]	Savings of Excavations (High)[4]	Total Excavation Savings[5]
2027	1,065	799	$21,013,973	$86,272,128	$33,685,112	$140,971,213
2028	1,118	839	$22,064,672	$90,585,734	$35,369,368	$148,019,774
2029	1,174	881	$23,167,905	$95,115,021	$37,137,836	$155,420,763
2030	1,233	925	$24,326,301	$99,870,772	$38,994,728	$163,191,801
2031	1,295	971	$25,542,616	$104,864,311	$40,944,464	$171,351,391
2032	1,359	1,020	$26,819,747	$110,107,526	$42,991,688	$179,918,960
2033	1,427	1,070	$28,160,734	$115,612,903	$45,141,272	$188,914,908
Total	8,672	6,504	$171,095,948	$702,428,395	$274,264,468	$1,147,788,811
3% Discount 7-Year Total						$1,015,707,526
7% Discount 7-Year Total						$872,108,367
3% Discount Annual						$145,101,075
7% Discount Annual						$124,586,910

1. Based on 75% reduction, which is the average of the range between 50-95%.
2. Based on 30% of excavations at the low-end excavation cost.
3. Based on 60% of excavations at the middle excavation cost.
4. Based on 10% of excavations at the high-end excavation cost.
5. Total cost of low, med, high excavation costs.

Table 15 summarizes the total annualized incremental costs calculated by the Associations and compares these findings to the calculations in Tables 13 and 14. The new total compliance cost is the difference between the current prescriptive regulations and the changes proposed by the Associations.

Table 15: Comparison of Dent Excavations

Annual Discount	Prescriptive	Dent ECA Excavation Savings	New Total Compliance Cost
3% Annual	$193,468,100	$145,101,075	$48,367,025
7% Annual	$166,115,879	$124,586,910	$41,528,970

D. Discovery of a Condition

As noted in the Associations' comments, the regulations do not specify what constitutes "adequate information," but they do require operators to remediate anomalous conditions on defined schedules, pursuant to §§ 192.714 and 192.933, once such information has been obtained (not to exceed 180-days absent a showing of impracticability, and approval from PHMSA of such showing when in an HCA). As such, the date of discovery, triggered once adequate information is obtained, is vitally important for regulatory compliance regarding remediation of anomalous threats within the requisite timeframe. The absence of clear regulatory language on this triggering event has led to ambiguity and uncertainty in the industry about PHMSA's expectations regarding the start date for remediating anomalous conditions. This, in turn, has led to disparate processes in the industry for when "discovery" occurs, and disparate treatment across PHMSA's regional offices in enforcement against compliance with repair timelines.

Specifically, the Associations recommended that PHMSA revise §§ 192.710(e) and 192.933(b) to clarify that the date of discovery is when engineering analyses are completed to properly characterize the severity of the anomaly.

Table 16: Impact of Applying Engineering Evaluation and Discovery Timeframe

	Annual ILI Tool Miles Inspected	**A. Number of annual occurrences when discovery results in a response condition (immediate, 1 year, 2 year)[1]**	**B. Number of annual occurrences when applying Engineering Evaluation would avoid a response condition is classified during the ILI tool run (192.714, 192.933)[2]**	**Total number of response conditions after applying Engineering Evaluation (A-B)**	**% of anomalies that could be repaired within the timeframe If PHMSA interpretation agrees that discovery begins after the anomaly evaluation[3]**
Operator Survey Data (crack, dent, corrosion)	47,323[4]	2,449[5]	488[6]	1,961	99%
Total 2024 Number of GT ILI Tool Mileage Inspected	95,748[7]	4,955[1]	991[2]	3,964	99%

1. Based on a .0518 rate of discovery that results in a response condition.
2. Based on a .20 reduction rate when applying Engineering Evaluation that would avoid a response condition.
3. Operators report that 99% of anomalies can be repaired in the timeframe if PHMSA agrees with the discovery time period beginning once the anomaly is evaluated. The 1% represent those instances, such as a river crossings, where it requires more than 5 days to mobilize and evaluate the anomaly.
4. Based on Association member survey data, 12 companies with an annual inspection mileage of 47,323 (all ILI data).
5. Number of annual occurrences when discovery results in a response condition (immediate, 1 year, 2 year).
6. Number of annual occurrences when applying engineering evaluation would avoid a response condition as classified during the ILI tool run (§§ 192.714, 192.933).
7. All ILI corrosion (34,301), cracking (14,567), dent (33,284), and other (13,595) mileage inspected in 2024 equals a total of 95,748

As outlined in the Associations' comments, clarifying the discovery date after completing engineering analyses ensures that anomalies are accurately characterized and conditions meet repair criteria. Applying proper engineering analysis to all identified conditions decreases unnecessary excavations when response conditions can be avoided based on preliminary report data. Table 17 summarizes the benefit of clarifying that the discovery date is when engineering analyses are completed, not tentative or preliminary.

Table 17: Avoided Excavations When Applying Engineering Evaluation

	GT ILI Tool Mileage	Discovery results in a response condition (immediate, 1 year, 2 year)[1]	Avoided condition by applying Engineering Evaluation[2]	Savings from Applying Engineering Evaluation (Low)[3, 7]	Savings from Applying Engineering Evaluation (Med)[4, 7]	Savings from Applying Engineering Evaluation (High)[5, 7]	Total Savings
2027	95,748	4,955	991	$26,069,683	$107,028,167	$41,789,346	$174,887,196
2028	102,450	5,302	1,060	$27,894,561	$114,520,139	$44,714,600	$187,129,300
2029	109,621	5,673	1,135	$29,847,180	$122,536,548	$47,844,622	$200,228,351
2030	117,295	6,070	1,214	$31,936,483	$131,114,107	$51,193,746	$214,244,335
2031	125,506	6,495	1,299	$34,172,037	$140,292,094	$54,777,308	$229,241,439
2032	134,291	6,950	1,390	$36,564,079	$150,112,541	$58,611,720	$245,288,339
2033	143,691	7,436	1,487	$39,123,565	$160,620,419	$62,714,540	$262,458,523
Total	828,602	42,881	8,576	$225,607,587	$926,224,014	$361,645,882	$1,513,477,483
3% Discount 7-Year Total							$1,336,344,927
7% Discount 7-Year Total							$1,144,121,843
3% Discount Annual							$190,906,418
7% Discount Annual							$163,445,978

1. Based on operator survey data of .0518 response condition per mile.
2. Operator survey data indicated that 20% of conditions would be avoided by applying Engineering Evaluation.
3. Based on 30% of conditions at the low-end excavation cost.
4. Based on 60% of conditions at the middle excavation cost.
5. Based on 10% of conditions at the high-end excavation cost.
6. Total cost of low, med, high conditions savings.
7. Does not include excavation CPI related escalation but Associations anticipate higher escalation rates than CPI.

V. CONCLUSION

In summary, the Associations urge PHMSA to revise Part 192 repair criteria, remediation guidelines, and integrity management, taking into consideration the costs and impacts outlined in this analysis. The Associations support eliminating internal inconsistencies and competing priorities that currently exist within the federal pipeline safety code. The changes included in this filing promote the adoption of cost-effective, efficient technologies, processes, and recent research that enlightens the industry how best to manage pipeline excavations and discovered anomalies.

As PHMSA develops a proposed rulemaking and accompanying PRIA, the Associations suggest using the empirical unit cost data and the mileage impacts as outlined throughout this analysis in this manner:

- PHMSA should adopt the Associations' excavation cost modeling presented in this analysis, including using the low, medium, and high excavation cost ranges. The Associations also believe that the excavation reductions within each of these cost ranges—30% (low-end), 60% (average), and 10% (high-end)—provide a reasonable basis for assessing the impacts. This is an assumption that a majority of the excavation costs would fall in the average range.
    - As shown in Table 1, the Associations estimate that gas transmission operators will spend about $499 million annually on current crack-like excavation compliance requirements. By adopting the Associations' proposals, the industry could eliminate $413 million each year of unnecessary spending. Some operators may direct some of these savings toward addressing higher system-wide risks. This will vary by operator, but such activities could include increasing ILI mileage, conducting more geohazard surveys, and exploring new technologies.

    - The Associations forecast that pipeline operators will increase the mileage assessed for cracks by 19 percent each year. This technology can detect smaller, less concerning features within the pipeline's body and seam, such as minor wall thickness variations, previously undetected geometric formations within manufacturing tolerances, and seam-related anomalies. The Associations believe that the suggested updates to crack-like anomalies will encourage more operators to adopt the latest, more sensitive technologies.

- Adopting a performance-based processes allows operators allocate resources more effectively, balancing safety benefits and compliance costs. For example, they could use an appropriate ECA with or without the FEA process to evaluate dents, which pose very low risk, and eliminating overly conservative criteria. Based on the Associations' analysis, adopting this provision alone would result in annual cost benefit of approximately $145 million.

- The ILI mileage estimates provided throughout this analysis, combined with the actual excavation rate data, should be used in the PHMSA analysis. Industry considers this an accurate estimate that includes over 2,900 total excavations (over the last 7-year reassessment period) across 132,000 miles of gas transmission, including interstate and intrastate gas operators.

The Associations support working with PHMSA to determine the reasonable effectiveness of the proposed rule or appropriate regulatory alternatives.

Respectfully submitted,

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VI. APPENDEX A: Reliability-Based Cost Benefit Analysis

A. Reliability Methodology

A reliability-based cost-benefit analysis (R-CBA) integrates probabilistic reliability modeling into traditional CBA to better inform decision-making under uncertainty.

The R-CBA -methodology is illustrated in Figure 1 below. This approach has been applied to the Associations' supplemental comments related to proposed changes to the prescriptive criteria within 49 CFR 192.712, 192.714, and 192.933. A full range of possible pipeline attributes (e.g. Nominal Pipe Size (NPS), Specified Minimum Yield Strength (SMYS), class location) and all their possible combinations were derived from data reported by gas transmission pipeline operators as part of the 2024 annual reporting process. Defect attributes were combined into a case matrix representing all possible combinations of pipe attributes and defect dimensions.

The Failure Pressure Ratio (FPR) was calculated for each case using RSTRENG for metal loss and CorLAS for crack defects. These are well documented models used by engineers to estimate the ultimate pressure a metal loss or crack would survive before leading to a large leak or rupture. The case matrix was then filtered for FPRs within the actionable range 1.1 (immediate) to 1.5 (scheduled) as outlined in §§ 192.714 and 192.933. For each case meeting the filtering criterion, the probabilistic versions of the RSTRENG and CorLAS calculations were conducted to evaluate the Ultimate Limit State probability of failure (PoF), which represents that chance that the case could result in a rupture or a large leak[21].

The consequence of failure was calculated using assumed population densities based on class location. Combined with the PoF, the risk for each case was evaluated against an established risk tolerance criteria to assess the adequacy of the current repair criteria versus the Associations' proposed changes.

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[21] Zhang, X., Zheng, Q., Leung, J., Adeeb, S. (2022). Reliability-Based Assessment of Cracked Pipelines Using Monte Carlo Simulation Technique With CorLAS™. ASME PVP Conference, PVP2022-80412.
Referenced in API RP 1176 (2016) and PHMSA 2019 rulemaking, and validated in publications like *IPC2018-78251* and *IPC2014-33563*. [store.veracity.com]

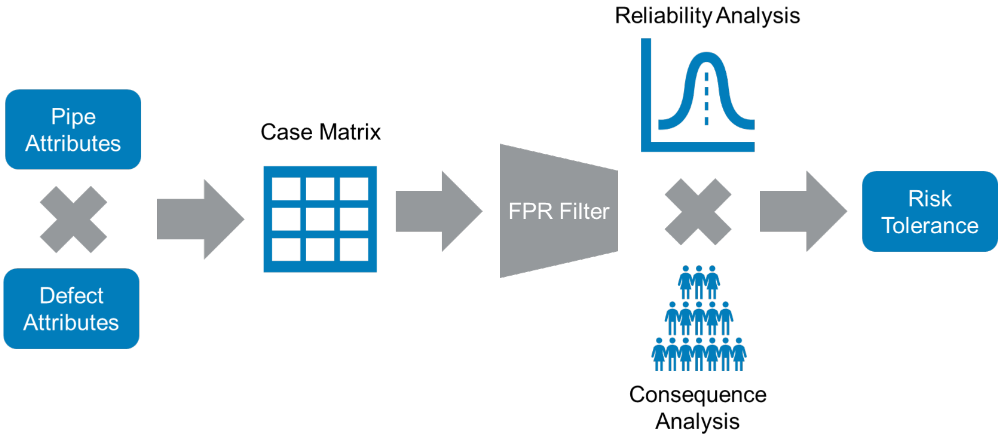

Figure 1. R-CBA Methodology Overview

The final step is to take the reliability results, shown as a percentage representing the difference between both scenarios (current vs. proposed) and multiply it to the cost associated with the criteria. This will typically involve the cost of all excavation activities associated with the criteria. The remainder of the document provides additional details on each aspect of the methodology described above, and Appendix B presents information on the data sources, assumptions, and process steps needed to complete an R-CBA.

Linking an R-CBA with the evaluation of regulatory criteria provides a powerful framework for ensuring that engineering and risk management recommendations are not only economically sound but also compliant with legal and safety mandates. It is a proven methodology to demonstrate that a requirement meets the as-low-as-reasonably practicable concept by comparing the value of risk reductions to their costs.

This model looks at consequences and failures associated with class locations. Combined with the PoF, the risk for each case was evaluated against an established risk tolerance criteria to assess the performance of current repair criteria to reduce risk for metal loss and crack/crack-like anomalies versus the Associations' proposed criteria.

B. Relationship Between Traditional and Reliability Methodologies

The Associations acknowledge the R-CBA methodology is new to the U.S. pipeline industry; however, they have been applied to many other industries, including those with the concern of low likelihood/high consequence events. As described above, R-CBA relies on the use of site-specific engineering data that requires less conservatism to achieve the same level of risk reduction. The fact that the reliability method is within 7.7% of the traditional method demonstrates that R-CBA provides results similar to traditional CBA approaches. The Associations believe R-CBA is appropriate for this and future rulemakings and is consistent with the risk based regulatory framework that PHMSA defined in the LNG ANPRM. The R-CBA results provided herein support the traditional CBA results presented in the body of the Association' submission.

C. Reliability-Based Methodology: Cracks

The Associations' applied a Hierarchical Monte Carlo Simulation to model the U.S. regulated gas transmission pipeline network. Using PHMSA's 2024 annual report data for each class location, the model generated 10 million unique pipeline attribute scenarios, reflecting the proportional distribution of key characteristics within the system for a given class location. The Associations then enriched the dataset by mapping each nominal pipeline size to a distribution of potential wall thicknesses, and each different pipeline decade of installation to a distribution of potential pipeline strengths. For each scenario, the operating pressure was assigned in accordance with the design standards specified in 49 CFR § 192.111.

Further, the Associations considered the guidelines from *API 579 Fitness for Service,* 2021 edition, on depth and length aspect ratios of crack anomalies on pipelines when modelling these potential anomalies. Upon reviewing these ratios and considering EMAT detection thresholds, the Associations applied crack anomalies with peak depths between 15% (EMAT general detection threshold) to 70 % of wall thickness (proposed threshold) at 1% of wall thickness increments, and total lengths between 1 to 20 inches at 1-inch increments. To account for all possible crack anomaly aspect ratios described in *API 579,* the Associations selected a 1% wall thickness increment on peak depths for cracks. Using this model allowed the Associations to use a larger data set collected from member companies. The model examined over 1,000 different crack-like anomalies as part of this study, providing a representative picture for crack management. Finally, the Associations applied the pipeline burst model CorLAS towards determining the failure pressure of the cracks under a semi-ellipse profile assumption.

The Associations used a generalized assessment methodology developed by CFER[22] to account for the probability of a pipeline rupture ignition, the potential impact radius of a jet fire, and the population density and occupancy rate within that radius [23]. The Associations calculated the consequence from a rupture event using Equation 1, where population density (p) is in people per hectare (ha), P is pressure in psi, and D is outer diameter in inches.

Equation 1

$$N_{rupt} = 4.4\ x\ 10^{-8} pPD^{3}$$

The associations derived this methodology by applying a probability of ignition model of 0.0125 D, calculating the hazard area for impact to human life for indoor and outdoor heat intensity thresholds, and applying the average probability of occupancy and average proportion of time spent indoors and outdoors.

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[22] IPC2004-321 *TARGET RELIABILITY LEVELS FOR DESIGN AND ASSESSMENT OF ONSHORE NATURAL GAS PIPELINES,* Maher Nessim, Wenxing Zhou, Joe Zhou, Brian Rothwell, Martin McLamb, 2004 ASME

[23] Target Reliability Levels for Design and Assessment of Onshore Natural Gas Pipeline

Representative population densities[24] were applied to each class location at non-high consequence area (HCA) locations to represent the average population near the potential impact radius of pipelines for each class locations. More information on defining population densities is provided in Appendix B. For this study, HCAs were defined as areas with occupancy levels comparable to a Class 3 location, as specified in 49 CFR § 192.903(1)(i). Accordingly, a Class 3 population density was applied to Class 1 and Class 2 pipelines designated as HCAs, as summarized in Table 1. Although these HCA segments are located within Class 1 or 2 areas, they were analyzed using Class 3 population densities while retaining their original design factors of 72% or 60% SMYS for MAOP modeling.

Table 1: Population Density for Pipelines of Different Class Location and HCA Status

Class Location	Population Density (people/ha)	HCA Population Density (people/ha)
1	0.04	18
2	3.3	18
3	18	18
4	100	100

The reliability of each crack-like anomaly has been analyzed using a Monte Carlo simulation of 1 million samples with a similar approach for corrosion. Material uncertainties were modelled using the uncertainties specified in Table 2, while toughness measurements were modeled using the same statistical distributions applied by PHMSA to establish an acceptable deterministic limit for toughness without material testing results available, as specified in 49 CFR 192.712.[25] At the pipe body, CVN was modelled as a Weibull distribution[26] with a shape parameter of 1.552 and a scale parameter of 54 ft-lbs. Similarly, at the seam weld, a CVN Weibull distribution has been applied with a slope parameter of 1.587 and scale parameter of 17 ft-lbs.

Table 12: Uncertainty in Material Properties

Material	Mean	COV (%)
Wall Thickness	1.01*Nominal Wall Thickness	1
Diameter	Nominal Outer Diameter	0.1
Young Modulus	29,500 ksi	4
Yield Strength	1.10*SMYS	3.5

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[24] CSA Group, Oil and Gas Pipeline Systems, Z662:2023 Annex O (Reliability-based design and assessment (RBDA) of onshore non-sour service natural gas transmission and LVP liquid hydrocarbon pipelines), *available at*, https://haisms.ir/images/iso/638893916081092974CAN%20CSA%20Z662-2024%20,%20Oil%20and%20Gas%20Pipeline%20Systems.pdf.

[25] Statistical Evaluation of Charpy Toughness Levels for Gas Transmission Pipelines

[26] A Weibull distribution best represent toughness because CVN toughness is always positive and the shape and scale parameters allow to model the right-skewed nature of the data, where most values cluster near the mean but there's a long tail of higher toughness values.

The defect measurement uncertainty has been modelled using the EMAT depth sizing uncertainty represented as +/- 15% WT at 80% confidence. The length sizing uncertainty was 0.787 inches at 80% confidence. The reliability of the cracks was examined without growth for the immediate criteria. For the scheduled criteria, two years of growth were applied to model non-HCA conditions, and 1 year of growth to model HCA conditions. A probabilistic growth rate was applied to model stress corrosion cracking (SCC) growth. For details on depth growth uncertainty, see Appendix B. It was modelled as a Gumbel[27] distribution with a mean of 4.63 mils per year (mpy) and standard deviation of 3.84 mpy. Length growth uncertainty was also modelled with a Gumbel distribution using a mean of 63 mpy and standard deviation of 90.5 mpy.

The Associations examined the reliability of the crack-like anomalies by estimating the likelihood of a pipeline rupture or large leak before mitigation. These failure probabilities are correlated to the EMAT ILI detected FPRs to determine what immediate and scheduled FPR conditions provide acceptable levels of reliability for each class location.

The Associations developed reliability targets to determine appropriate FPR criteria for the various threats and situations. These reliability targets define acceptable pipeline reliability tolerances for different class locations and HCA status, where more tolerance is acceptable at lower consequence areas. The Associations calculated reliability targets for each pipeline attribute by applying the societal risk maximum tolerable threshold from Oil and Gas Pipeline Systems CSA Z662: 2023 Annex B with an additional minimum reliability limit constraint of 10^{-3} failure per year. The reliability target was calculated as:

Equation 2

$$Reliability\,Target = MIN(10^{-3}, 10^{-LOG10(Fatality)-3})$$

The U.S. Department of Energy (DOE) uses a similar benchmark for nuclear facilities, where the allowable risk of cancer fatality from operations must not exceed 10^{-3} per year. This demonstrates clear alignment with risk-tolerability practices for other critical energy infrastructure. While DOE criteria could be used directly, the CSA Z662 Annex B approach offers two advantages:

1. **Consistency** with the 10^{-3} limit at low-population (Class 1) locations.

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[27] The Gumbel distribution often appears in contexts involving extreme values or maximum/minimum deviations. Gumbel captures the heavy tail behavior better than normal or lognormal distributions, meaning it accounts for rare but significant outliers. EMAT depth errors often skew toward overestimation or underestimation, not perfectly centered hence why the Gumbel distribution is a better goodness-of-fit for depth error than normal or uniform distributions.

2. **More granularity** for higher-class locations, which is important for natural-gas pipelines with varying population densities.

Once the reliability target is calculated for a modelled pipeline attribute, the average reliability target of the U.S. gas transmission system is taken per class location and HCA status.

The reliability of various FPR criteria was evaluated using advanced statistical regression modeling. Separate regressions were performed for each pipeline threat, class location, and HCA/non-HCA condition. For each FPR criterion, the logarithmic-weighted mean burst probability was estimated. These burst probabilities were then compared across the potential FPR criteria to develop a statistical regression model representing the mean predicted reliability and its associated prediction interval. The FPR limit was defined as the intersection point between the 80th percentile of the regression prediction interval and the reliability target.

For the consideration of a failure pressure ratio for immediate repair, the reliability results evaluated the efficacy of a 1.1 x MAOP criteria for each class location, a Monte Carlo simulation was run across the U.S. gas transmission system. The results from this analysis case at the pipe body are summarized in Table 3. It shows that a criterion of 1.1 is well suited for class locations 1 to 4. While the analysis shows that the safety factor is conservative for class 1 to 3, class 4 is very close, i.e., a very small safety margin. A detailed review of site-specific consequences should be factored into the decision to account for very highly populated areas when using a performance-based approach.

Table 3: Reliability Results alignment to proposed Safety Factors for Burst Pressure Criteria for Crack Immediate Repair Per Class Location

Class Location	Reliability Target	Corresponding FPR
1	10^{-3}	less than 1.1
2		less than 1.1
3		1.1
4		1.1*

*Class 4 locations would require a thorough review of site-specific circumstances to ensure risk is fully captured.

Using the same sample data as described in Reliability-Based Cost Benefit Detailed Analysis Inputs and Assumptions section below, the Associations computed an estimate of relative cost reduction. Here, the population of crack anomalies sampled across the representative pipe attributes were assessed considering all related proposed crack criteria (immediate and scheduled) resulting in a significant cost reduction, as outlined below. As expected, the addition of an immediate FPR criterion will result in a slight increase in relative cost compared to the option of only revising the depth criteria.

The reliability assessment demonstrates that the proposed threshold of 70% would equate to a probability of failure for small leak (i.e. a risk threshold) of 10^{-3} maintaining safe operating conditions using the reliability limits from CSA Z662 Annex B as a reference.

The study leverages data from the Association membership survey, which collected responses representing 132,000 miles of gas transmission pipelines—nearly **44% of the U.S. gas transmission system** (approximately 300,000 miles). This provides a robust sample for extrapolating industry-wide implications.

Current Prescriptive Approach

Under prescriptive crack criteria, the number of digs driven by these requirements averages **885 excavations annually** for the Associations' membership.

The average cost per excavation ranges from **$87,688 to $421,688**, depending on complexity and location. Therefore, the **annual cost** for the surveyed mileage considering a weighted distribution for the cost per dig is (Cost data from Table 2: Excavation Costs Derived from Data of 2900 Excavations Across 12 Operators, from the main document):

Table 4: Calculation of the Total Cost of Excavations for the Gas Transmission System – Current Criteria

	Lower bound	Average	Upper bound	Total
Weighted distribution	.30	0.60	0.10	1
Total crack dig - survey	885			
Cost per dig	$87,688	$180,000	$421,688	$176,475
Estimate dig program for crack - survey	$23,281,164	$95,580,000	$37,319,388	$156,180,552

When scaled to the entire U.S. gas transmission system, the total cost of prescriptive crack criteria is estimated at **$355 million per year** in 2024 dollars (~$156 million x (1-0.44)).

Impact of Performance-Based Approach

Reliability-based methods allow operators to prioritize digs based on actual risk rather than rigid prescriptive thresholds. The analysis indicates that adopting a performance-based approach could **reduce spending on crack-related digs by approximately 69%**. For each class location, the ratio is calculated by examining the Monte-Carlo crack anomaly combinations and defining how many anomalies would meet the current depth and fitness for purpose thresholds for both immediate and scheduled criteria. This is then compared to the number of anomalies that would fail the reliability criteria of 10^{-3}, which represent the performance approach. Finally, each class location results are aggregated to a total accounting for the class location distribution in the gas transmission system (see Table 17 later in the Appendix).

Applying this reduction to the industry-wide cost, i.e., 31% remaining:

$355 million× (0.31) =$ 110 million

This represents a potential **annual savings of $245 million**, while maintaining or improving safety outcomes through risk-informed decision-making, and by reducing unnecessary construction activities.

Table 5: Crack-Like Excavations Traditional Versus Performance-Based Methods

Topic Area	Current Annual Cost	Traditional Method Savings: Annual	Reliability Method Savings: Annual
1a. Crack-like Excavation (2024)	$320,000,000 (Traditional) $355,000,000 (Performance-Based)[1]	$264,000,000[1]	$245,000,000[1]
1b. 7-year Annualized (2027-2033)	$499,824,874	$413,283,676	

5. Risk based approach in place of prescriptive repair requirements of 192.714 and 192.933 (focused on corrosion and dent, cracking analyses completed in Section 1)

The following analysis is similar to the crack evaluation shown earlier in the document and includes the results of that evaluation in its final summary of costs and benefits below. A Hierarchical Monte Carlo Simulation was employed to model the U.S. regulated gas transmission pipeline network. Using the reported data from PHMSA for each class location, 10 million unique pipeline attribute scenarios were generated, reflecting the proportional distribution of key characteristics within the system for a given class location. The gas transmission pipeline dataset available to the Associations further enriched the dataset by mapping each nominal pipeline sizes to a distribution of potential wall thicknesses, and each different pipeline installation decades to a distribution of potential pipeline strengths. For each scenario, the operating pressure was assigned in accordance with the design standards specified in 49 CFR 192.111.

The population of corrosion flaws modelled was defined using guidelines from *ASME B31G-2012*[28] where a corrosion anomaly can have a depth range between 10% to 80% of the wall thickness and a length range between 1 and 20 inches. An increment of 5% of the wall thickness

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[28] This is the version that was available when the model was initially developed. In term of the topic, nothing has materially changed in the standard.

was applied to depth and a 1-inch increment was applied to length, representing 300 different plausible corrosion anomaly scenario to be inputs in the model.

A generalized assessment methodology that was developed by CFER[29] has been applied for this study accounting for the probability of ignition of a pipeline rupture, the potential impact radius of a jet fire, and the population density and occupancy rate within that radius [30]. The expected impact to human life from a rupture event was calculated using Equation 1 where population density (p) is in people per hectare (ha), P is pressure in psi, D is outer diameter in inches.

Equation 3

$$N_{rupt} = 4.4\ x\ 10^{-8} pPD^{3}$$

This methodology was derived by applying a probability of ignition model of 0.0125 D, calculating the hazard area for impact to human life for indoor and outdoor heat intensity thresholds, as well as applying the average probability of occupancy and average proportion of time spent indoors and outdoors.

Representative population densities[31] were applied to each class location at non-HCA locations to represent the average population near the potential impact radius of pipelines for each class locations. For this study, HCAs were defined as areas with occupancy levels comparable to a Class 3 location, as specified in 49 CFR 192.903(1)(i). Accordingly, a Class 3 population density was applied to Class 1 and Class 2 pipelines designated as HCAs, as summarized in Table 6. Although these HCA segments are located within Class 1 or 2 areas, they were analyzed using Class 3 population densities while retaining their original design factors of 72% or 60% SMYS for MAOP modeling.

Table 6: Population Density for Pipelines of Different Class Location and HCA Status

Class Location	Population Density (people/ha)	HCA Population Density (people/ha)
1	0.04	18
2	3.3	18
3	18	18
4	100	100

The pipeline attributes are used to model the pressure and diameter of pipelines system wide which impact the probability of ignition and hazard area of a pipeline failure. For *Corrosion*, the pipeline attributes matched to corrosion with an FPR between 1.10 to 1.50 were used with their representative count outlining how prominent the attribute is in the U.S System as a weighting

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[29] IPC2004-321 *TARGET RELIABILITY LEVELS FOR DESIGN AND ASSESSMENT OF ONSHORE NATURAL GAS PIPELINES,* Maher Nessim, Wenxing Zhou, Joe Zhou, Brian Rothwell, Martin McLamb, 2004 ASME

[30] Target Reliability Levels for Design and Assessment of Onshore Natural Gas Pipeline

[31] CSA Z662:2023 Annex O

factor. For each class location, and HCA/Non-HCA situation, the dataset was filtered prior to performing a consequence assessment and determining reliability targets. To complete the evaluation for repair criteria related to corrosion, uncertainty in pipeline material properties has been modelled by applying the mean bias and coefficient of variations (COV) shown in Table 7.

Table 7: Uncertainty in Material Properties

Material	Mean	COV (%)
Wall Thickness	1.01*Nominal Wall Thickness	1
Diameter	Nominal Outer Diameter	0.1
Young Modulus	29 500 ksi	4
Yield Strength	1.10*SMYS	3.5

The defect measurement uncertainty has been modelled with a general corrosion morphology sizing tool error. The effective depth sizing error is +/- 8 %WT with 80% confidence at the pipe body and +/- 12 %WT at the girth weld. The length error was modelled with a standard deviation of +/- 0.28 inches at 80% confidence at the pipe body and +/- 0.47 inches at the girth weld. The reliability of each corrosion anomaly combined with different pipe attributes has been analyzed using a Monte Carlo simulation with 1M samples.

The reliability of all corrosion-pipe attribute situations was examined without growth for the immediate criteria. For the scheduled criteria, two years of growth has been applied at non-HCA locations, and one year of growth at HCA locations to coincide with the remediation timelines within CFR 192.714 and 192.933. Two separate sets of depth growth rates have been applied to the effective depth of corrosion anomalies: 3 mpy to represent a moderate growth rate, and 6 mpy to represent high aggressive growth in the presence of cathodic protection shielding. For each of these corrosion-pipe combinations, the likelihood of a pipeline burst before mitigation has been estimated.

Reliability targets were developed to determine appropriate failure pressures ration (FPR) criteria for the various threats and situations. These reliability targets define acceptable pipeline reliability tolerances for different class locations and HCA status, where more tolerance is acceptable at lower consequence areas. The reliability target was calculated for each pipeline attribute by applying the societal risk maximum tolerable threshold from *CSA Z662: 2023 Annex B* with an additional minimum reliability limit constraint of 10^{-3} failure per year. The reliability target was calculated as:

Equation 4

$$Reliability\,Target = MIN(10^{-3}, 10^{-LOG10(Fatality)-3})$$

Once the reliability target is calculated for a modelled pipeline attribute, the average reliability target of the U.S. system is taken per class location and HCA status.

The reliability of various FPR criteria was evaluated using advanced statistical regression modeling. Separate regressions were performed for each pipeline threat, class location, and HCA/Non-HCA condition. For each FPR criterion, the logarithmic-weighted mean burst probability was estimated. These burst probabilities were then compared across the potential FPR criteria to develop a statistical regression model representing the mean predicted reliability and its associated prediction interval. The FPR limit was defined as the intersection point between the 80th percentile of the regression prediction interval and the reliability target.

Using the same sample data as described in the methodology section, an estimate of relative cost reduction was computed. Here, the population of crack anomalies sampled across the representative pipe attributes were assessed under the proposed criteria. A significant reduction in cost is expected as outlined in the table below. As expected, the addition of an immediate FPR criterion will result in a slight increase in relative cost compared to the option of only revising the depth criteria.

The reliability assessment demonstrates that the proposed threshold of 70% would equate to a probability of failure for small leak (i.e. a risk threshold) of 10^{-3} maintaining safe operating conditions in accordance with the reliability limits from CSA Z662 Annex B used as a reference.

The study leverages data from **the Associations' membership survey**, which collected responses representing **132,000 miles** of gas transmission pipelines—nearly **44% of the U.S. network** (approximately 300,000 miles).

Table 8: Operator Survey Excavations with Weighted Factor (proportion of digs per threat over total of digs for all threats).

Threat	Number of excavations	Weighted Factor
Cracking	886	0.30
Corrosion	1,380	0.48
Dent/Other	638	0.22
Total	2,904	1

Under the current prescriptive repair criteria, the total spending for mitigation activities driven by these requirements is $317,000,000 annually for the members that provided data. To define a low and high bound value, we took the spend, normalized as a cost per mile and define the 25% and 75% quartile and use the proportion to the average and applied this on the total estimated spend.

Table 9: Total Surveyed Cost of Excavations Survey Data

	Results
Total cost for integrity excavation	$317,000,000
Cost per mile average	$6768/mi
Low end cost per mile (25% quartile)	$2064/mi
High end cost per mile (75% quartile)	$9278/mi

Based on the quartile calculated in the table above, the scaled range of spending to the entire U.S. gas transmission system is:

Table 10: Calculation of the Total Cost of Excavations for Gas Transmission Systems

	Lower bound	Average	Upper bound	2024 Total
Weighted distribution aligned to cost per dig calculation of Table 2 Excavation Costs from the Main Document)	0.30	0.60	0.10	1
Total U.S. Transmission mileage	300,000 mi			
Cost per mile (from Table 9)	$2064	$6768	$9278	N/A
Estimated Dig program cracking				$355M[1]
Estimated Dig Program Dent & Corrosion				$1.327B[2]
Estimate dig program for 192.714 & 192.933 repairs	$185,760,000	$1,218,240,000	$278,340,000	$1,682,340,000

1. Based on reliability-based analyses in Section 1
2. Total cost of $1.682B minus $355M in crack program costs

Reliability-based methods allow operators to prioritize digs based on actual risk rather than rigid prescriptive thresholds. The analysis indicates that adopting a performance-based approach could reduce spending significantly.

Table 11: Calculation of the 2024 Cost of Excavation for the Proposed Criteria for all Threats on Gas Transmission System when Using a Performance-based Approach

All Threats	Weighted Factor	Relative Cost Ratio (Proposed / Current)	Adjusted Performance Based Cost	Total Reliability Method Benefit
Cracking	0.30	31%	$156,457,620	$245M
Corrosion	0.48	88%	$710,620,416	$496M
Dent/Other	0.22	20%	$74,022,960	
Total	1	N/A	$941,100,996	$741M

This represents savings in the order of $741 million per year for the gas pipeline transmission industry.

D. Reliability-Based Cost Benefit Detailed Analysis Inputs and Assumptions

1. Purpose

This section summarizes a reliability-based cost–benefit analysis (CBA) framework using Monte-Carlo simulation to support decisions for pipeline anomalies repair criteria. The method is designed to assess and compare repair criteria and integrity-management requirements in 49 CFR Part 192 while providing a defensible, quantitative basis for selecting between current and proposed regulatory language.

2. Overview of the Monte-Carlo Method

The CBA simulates thousands of possible future scenarios for the anomaly, capturing uncertainties in defect growth, failure timing, consequences, and repair logistics.

Monte-Carlo is well suited for this analysis for the following:

1. **Complex, Nonlinear Limit States**
    - defect growth and failure involve nonlinear fracture mechanics equations (e.g., stress intensity factor, toughness, residual stresses).
    - Monte Carlo can handle these nonlinearities without requiring simplifications.
2. **Multiple Uncertainties**
    - Inputs like material toughness (CVN), defect size, pressure, weld properties, and defect detection errors are all random variables.
    - Monte Carlo easily accommodates **any distribution type** (Weibull, lognormal, etc.) and correlation between variables.
3. **Rare Event Estimation**
    - Failure probabilities in pipelines are often very low (e.g., 10^{-4} or less).
    - Monte Carlo can estimate these probabilities accurately if enough samples are used (or with variance reduction techniques).
4. **No Need for Linearization**
    - Unlike other reliability methods like First Order Reliability Method or Second Order Reliability Method, Monte Carlo does not require approximating the limit state function.
    - This avoids errors when the failure surface is highly curved or discontinuous.
5. **Flexibility for Scenario Analysis**

  - Easy to incorporate **inspection data**, **growth models**, and **time-dependent reliability** without changing the core method.

2.1 Key Inputs

- **Defect characteristics:** type, size, remaining wall thickness, tool tolerance.
  - Uncertainty in ILI anomaly sizing contributes significantly to reliability calculations. For corrosion anomalies, the study applied the sizing uncertainty parameters associated with the Baker Hughes MF4 super high-resolution hall tri-axial tool. Under this tool specification, general corrosion has an 80% confidence depth sizing error of ±8% wall thickness at the pipe body and ±12% near the girth weld. The corresponding length sizing errors are ±0.28 inches at the pipe body and ±0.47 inches near the girth weld. For crack anomalies, Rosen's third-generation EMAT tool was used, which has an 80% confidence depth sizing error of ±15% wall thickness, with an additional ±5% error applied when wall thickness exceeds 0.40 inches.

    These specific tools have been selected as a representation of available tools and typical specifications for these technologies. Small variation in performance and specifications are expected between different vendors or different platform within a vendor service offering.

Table 12: Uncertainties Associated with Defect Characteristics

Variable	Source	Context
Corrosion ILI Depth Sizing Error	Baker Hughes: MF4 HD/HALL TRI AXIAL	±8% WT (pipe body) and ±12% WT (girth weld), 80% confidence.
Corrosion ILI Length Sizing Error	Baker Hughes: MF4 HD/HALL TRI AXIAL	±0.28 in (body), ±0.47 in (girth weld).
Crack ILI Depth Sizing Error	Rosen: Third Generation EMAT	±15% WT at 80% confidence + additional ±5% WT if wall thickness > 0.40 in.

- **Pipeline Properties and Operating conditions:** Diameter, wall thickness, MAOP, pressure cycles, soil/environmental factors, etc.

- The uncertainty associated with pipeline attributes was derived from two trusted sources. The first is the Canadian Standards Association, which provides guidance in CSA Z662 Annex O for characterizing uncertainty in transmission pipeline properties. As summarized in Table 13, a pipeline's wall thickness and diameter are represented with uncertainty relative to their nominal values. Similarly, uncertainty in yield strength is modelled from the material's specified minimum yield strength (SMYS), and Young's modulus is also treated as a stochastic parameter.

Table 13: Uncertainties Obtained from CSA Z662 Annex O

Material	**Mean**	**COV (%)**
Wall Thickness	1.01*Nominal Wall Thickness	1
Diameter	1*Nominal Outer Diameter	0.1
Yield Strength	1.10*SMYS	3.5
Young Modulus	29,500 ksi	4

- Additional uncertainty in pipeline toughness was characterized by distributions from the Statistical Evaluation of Charpy Toughness Levels for Gas Transmission Pipelines study, developed by Structural Integrity and adopted by PHMSA when establishing minimum CVN toughness requirements. Based on this work, pipe body toughness is modelled using a Weibull distribution with a shape parameter of 1.552 and a scale parameter of 54 ft-lbs, while seam toughness is modelled using a Weibull distribution with a shape parameter of 1.587 and a scale parameter of 17 ft-lbs. A Weibull distribution best represent toughness because CNV toughness is always positive and the shape and scale parameters allow to model the right-skewed nature of the data, where most values cluster near the mean but there's a long tail of higher toughness values.
- The PHMSA Annual Form data was digitized into a database environment. The worksheet "GT AR Part A to D" was filtered such that report_submission_type was set to "initial" and PartA5Commodity to "Natural Gas." The same commodity filter was applied to all other worksheets used in this study.

  NPS information was obtained from "GT AR Part H," where variables such as PARTHON20 and PARTON24 represent the onshore mileage of NPS 20 and NPS

24 pipelines. All NPS variables were aggregated by report_number and linked back to "GT AR Part A to D" using the Report_Number column. This produced two key metrics per operator:

- The total onshore mileage reported, and
- The relative mileage contribution of each NPS size.

Vintage information was sourced from "GT AR Part J." Variables such as PARTJON197079 and PARTJON198089 denote mileage installed in the 1970s and 1980s. These values were aggregated per report_number and linked to "GT AR Part A to D" to obtain relative mileage percentages by installation decade.

Class location and HCA information were extracted from "GT AR Part L," where PARTLTONC1, PARTLTONC2, PARTLTONC3, and PARTLTONC4 represent class 1 through class 4 mileage, and PARTLTONHCA represents HCA mileage. These values were processed to obtain each operator's relative class distribution and HCA percentage. The system-wide mileage contribution of each operator for each class location was also estimated. The outcome of these processing steps is a consolidated PHMSA Annual Form Summary dataset.

Table 14: Source Data for Pipeline Attributes and Operating Conditions

Variable	Source	Context
Nominal Pipe Size (NPS)	PHMSA 2024 Gas Transmission & Gathering Annual Form – **GT AR Part H**	Variables like PARTHON20, PARTON24 represent onshore mileage for NPS 20 and NPS 24. Aggregated by report_number to compute each operator's NPS distribution.
Vintage (Installation Decade)	PHMSA 2024 Annual Form – **GT AR Part J**	Variables like PARTJON197079, PARTJON198089 represent pipeline mileage installed in the 1970s and 1980s. Used to determine operator-level decade distribution.
Class Location Mileage (1–4)	PHMSA 2024 Annual Form – **GT AR Part L**	PARTLTONC1 to PARTLTONC4 represent mileage by class location. Used for class distribution weighting in simulations.

HCA Mileage	PHMSA 2024 Annual Form – **GT AR Part L**	PARTLTONHCA represents high-consequence area mileage. Used to probabilistically assign HCA status.
Total Onshore Mileage	PHMSA 2024 Annual Form – **GT AR Part A to D**	Filtered on report_submission_type = "initial" and PartA5Commodity = "Natural Gas". Basis to calculate operator weighting.
Operator Mileage Weighting	PHMSA Annual Form Summary (merged dataset)	Used in Monte Carlo simulation to sample operators proportionally to their system mileage for each class location.
Wall Thickness Histogram	Association Operator Dataset	Wall thickness distributions by NPS × vintage used for probabilistic sampling in the simulation.
Pipe Grade Histogram	Association Operator Dataset	Pipeline grade distributions (e.g., X52, X60, X70) binned by NPS and vintage.
Outer Diameter	Deterministic conversion from NPS	Used to estimate MAOP and burst pressure.
MAOP Estimate	Barlow's Equation + Class Design Factors	Design factors: 72% (Class 1), 60% (Class 2), 50% (Class 3), 40% (Class 4).
Wall Thickness Uncertainty	CSA Z662 Annex O	Modelled as: Mean = *1.01 × nominal*, COV = 1%.
Outer Diameter Uncertainty	CSA Z662 Annex O	Mean = *1.00 × nominal*, COV = 0.1%.
Yield Strength Uncertainty	CSA Z662 Annex O	Mean = *1.10 × SMYS*, COV = 3.5%.
Young's Modulus	CSA Z662 Annex O	29,500 ksi with 4% COV.
Pipe Body Toughness Distribution	Structural Integrity / PHMSA – *Statistical Evaluation of Charpy Toughness Levels*	Weibull: Shape = 1.552, Scale = 54 ft-lbs. Used for pipe body toughness variability.
Seam Toughness Distribution	Structural Integrity / PHMSA – *Statistical Evaluation of Charpy Toughness Levels*	Weibull: Shape = 1.587, Scale = 17 ft-lbs.

- **Failure model parameters:** defect growth rate distribution, fracture-mechanics or empirical failure thresholds.
  - Another source of uncertainty is anomaly growth between ILI detection and remediation. For corrosion, a conservative deterministic growth rate of 6 mpy was applied to the average or effective depth of each cluster. According to NACE RP0775-2005, table 2, this represents a high-end growth rate, selected to ensure that even rare high-growth events are captured within the analysis.
  - For SCC, a probabilistic approach was applied using results from an internal INGAA operator study. SCC depth growth was modelled with a Gumbel distribution having a mean of 4.63 mpy and a standard deviation of 3.84 mpy. A corresponding Gumbel distribution was used for SCC length growth, with a mean of 63 mpy and a standard deviation of 90.5 mpy. The Gumbel distribution often appears in contexts involving extreme values or maximum/minimum deviations. Gumbel captures the heavy tail behavior better than normal or lognormal distributions, meaning it accounts for rare but significant outliers. EMAT depth errors often skew toward overestimation or underestimation, not perfectly centered hence why the Gumbel distribution is a better goodness-of-fit for depth error than normal or uniform distributions.

Table 15: Source Data and Assumptions for Defect Growth

Variable	Source	Context
Corrosion Growth Rate	NACE RP0775-2005	Deterministic 6 mpy depth growth applied to cluster effective depth. Represents high-end rare event growth.
SCC Growth Rate	INGAA Operator SCC Study	A probabilistic SCC growth rate was applied with a depth growth Gumbel distribution with a mean of 4.63 mpy and standard deviation of 3.84 mpy. A probabilistic length growth Gumbel distribution was also applied from this work with a mean of 63 mpy and standard deviation of 90.5 mpy.

- **Failure Pressure Ratio (FPR) Calculation**
  - The Failure Pressure Ratio (FPR) is defined as the ratio of predicted failure pressure to the Maximum Allowable Operating Pressure (MAOP).

    - For each sampled defect and pipeline attribute, the predicted failure pressure is calculated using industry models.
    - For corrosion/metal loss, FPR was calculated for each case using RSTRENG for metal loss. RStreng is a well documented model used by engineers to estimate the ultimate pressure a metal loss leading to a large leak or rupture. It is one of the acceptable model identified within CFR 192.712(b).
    - For cracking, FPR was calculated for each case using CorLAS. CorLAS is a well documented model used by engineers to estimate the ultimate pressure a cracking leading to a large leak or rupture. While not specifically reference in CFR 192.712(d), the model meets the requirements highlighted in CFR 192.712(d) and multiple articles provide validated assessment of its appropriateness to manage cracking. One such example is: *Zhang, X., Zheng, Q., Leung, J., Adeeb, S. (2022). Reliability-Based Assessment of Cracked Pipelines Using Monte Carlo Simulation Technique With CorLAS™*. ASME PVP Conference, PVP2022-80412. It is also included in the 2016 API RP 1176 *Assessment and Management of Cracking in Pipelines*.
    - The case matrix was then filtered for FPRs within the actionable range 1.1 (immediate) to 1.5 (Scheduled) as outlined in 49 CFR 192.714 and 192.933. For each case meeting the filtering criterion, the probabilistic versions of the RSTRENG and CorLAS calculations were conducted to evaluate the Ultimate Limit State probability of failure (PoF), which represents that chance that the case could result in a rupture or a large leak
    - Only defects with FPRs in the actionable range (typically 1.1 to 1.5) are considered for further analysis.
- **Consequence parameters:** ignition probability, expected casualties, property damage, environmental impact.
    - The consequence of failure was calculated using assumed population densities based on class location based on CSA Z662, Annex O, table O.2.
    - HCAs were defined as areas with minimum occupancy levels comparable to a Class 3 location, as specified in 49 CFR 192.903(1)(i).

Table 16: Population Density for Pipelines of Different Class Location and HCA Status

Class Location	Population Density (people/ha)	HCA Population Density (people/ha)
1	0.04	18
2	3.3	18
3	18	18

4	100	100

  - One Operator validated that the Population Density was representative of the US gas transmission system using cell phone usage data along their right of way. Results shown in Table 16 are aligned to the data presented in the second column of Table 17.

Table 17: Population Density for Pipelines of Different Class Location Using Cell Usage Data

Class Location	Population Density (people/ha)
1	0.16
2	1.32
3	8.09
4	99.04

  - A generalized assessment methodology that was developed by CFER has been applied for this study accounting for the probability of ignition of a pipeline rupture, the potential impact radius of a jet fire, and the population density and occupancy rate within that radius. The expected impact to consequence from a rupture event was calculated using Equation 1 where population density (p) is in people per hectare (ha), P is pressure in psi, D is outer diameter in inches. This methodology was derived by applying a probability of ignition model of 0.0125 D, calculating the hazard area for impact to human life for indoor and outdoor heat intensity thresholds, as well as applying the average probability of occupancy and average proportion of time spent indoors and outdoors.

Equation 1: N_rupt=4.4 x 10^(-8) pPD^3

- **Cost data:** Repair cost, excavation number per threats and associated cost.
  - Cost data and quantity units, when relevant, have been assessed by surveying the Association's membership.
  - Cost description and provenance have can be found describe in the body of the submission within the various relevant sections.

2.2 Simulation Steps - Hierarchical Monte Carlo Simulation

The U.S. gas transmission pipeline network was modelled using a hierarchical Monte Carlo simulation consisting of 10 million realizations per class location. The steps are as follows:

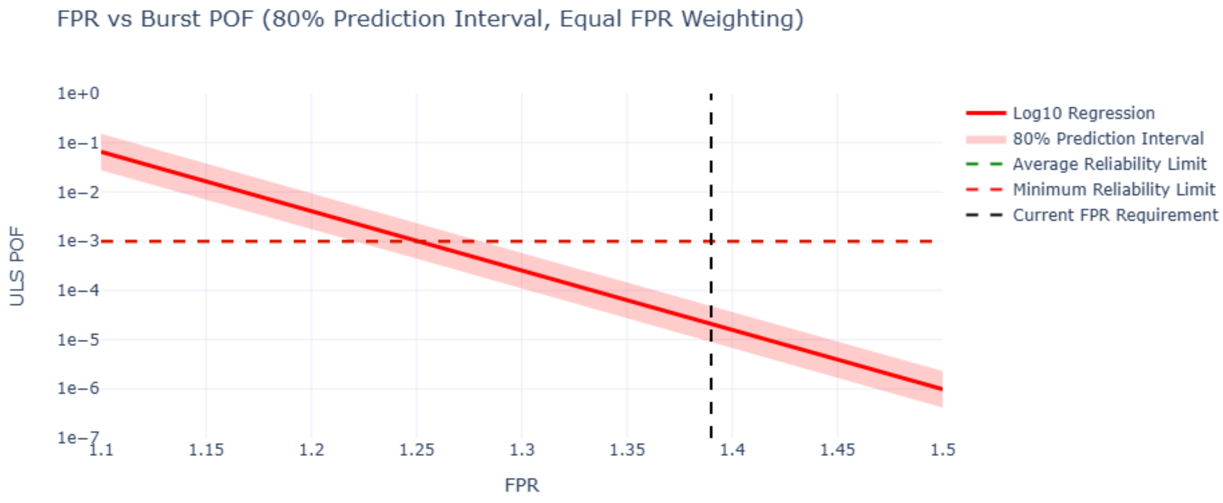
1. Select a class location of interest.
2. Sample one operator for each of the 10 million realizations based on that operator's mileage contribution to the selected class location.

3. For each sampled operator, probabilistically select an NPS and vintage according to that operator's relative mileage distributions.
4. For each selected NPS, sample a wall thickness from the corresponding histogram.
5. For each selected installation decade, sample a pipeline grade from the corresponding histogram.
6. Probabilistically assign an HCA status based on the sampled operator's percentage of HCA mileage.
7. Convert the selected NPS to an outer diameter deterministically.
8. Estimate MAOP using Barlow's equation with design factors of 72 percent SMYS for class 1, 60 percent for class 2, 50 percent for class 3, and 40 percent for class 4.

3. Defining the Reliability Benefit

- Using the results of the Monte-Carlo simulations
  - For each defect scenario, a Monte Carlo simulation is run to account for uncertainties in defect sizing, material properties, and model errors.
  - The simulation produces a distribution of possible outcomes, from which the Probability of Failure (POF) for each scenario is calculated.
  - The results are plotted as POF vs. FPR graph for each class location and defect type, with regression lines and prediction intervals, typically the 80th percentile. The 80th percentile was selected to match validation level 2 outlined in API 1163 Qualification of Inline-Inspection System.

Figure B1: Example of the POF vs. FPR graph. The example is for a Class 1/non-HCA corrosion scheduled FPR criteria with a 6 mpy growth rate growth to 2 years. It shows the scheduled criteria of 1.39 (vertical dash line) is equivalent to a risk target of $\sim 10^{-4.5}$, which is more conservative than the target set of 10^{-3}.



4. Defining Proposed vs. Current Criteria

- Based on the simulation results, proposed FPR criteria are set to align with risk limits (i.e., where the 80th percentile POF meets the reliability target).
- For each criterion (immediate, scheduled, monitored), the number of actionable defects under both current and proposed criteria is counted.
- The ratio of proposed vs. current is calculated as Relative Cost Ratio = Number of actionable defects under proposed criteria divided Number under current criteria
- This ratio quantifies the potential cost savings (or potential increase) from adopting risk-based criteria, independent of the actual cost per repair.
- For each criterion or group of criteria, the results for each class location are then aggregated based on the distribution of miles for each class location. That ration of proposed/current can then be used with the cost data to calculate the cost of the proposed criteria and the potential changes in cost compared to the current criteria.