December 15, 2021

Alan K. Mayberry, P.E.
Associate Administrator
Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
1200 New Jersey Avenue, SE
Washington, DC 20590

Re: Petition for Reconsideration of Final Rule, "Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments", PHMSA-2011-0023 (Nov. 15, 2021)

Dear Mr. Mayberry:

GPA Midstream Association (GPA) and the American Petroleum Institute (API) (collectively, the Petitioners) respectfully submit this Petition for Reconsideration (Petition) of the Final Rule that the Pipeline and Hazardous Materials Safety Administration (PHMSA or the Agency) published in the *Federal Register* on November 15, 2021, in the above-captioned proceeding. The Final Rule contains new reporting requirements and safety standards for onshore gas gathering lines.

GPA and API appreciate the Agency's efforts to bring the rulemaking process to a conclusion. The Petitioners have been actively engaged in this proceeding for more than a decade, offering comments, participating in meetings, and developing two industry standards, API Recommended Practice 1182, *Construction, Operation, and Maintenance of Large Diameter Rural Gas Gathering Lines*, 1st Edition, and API Recommended Practice 80, *Definition of Onshore Gas Gathering Lines*, 2nd Edition, to advance the industry's shared interest in establishing reasonable, risk-based safety standards and reporting requirements for rural gas gathering lines. While the Final Rule achieves these objectives in some respects, the Petitioners are seeking reconsideration of several provisions due to PHMSA's failure to comply with the requirements in the Pipeline Safety Act and Administrative Procedure Act.

Of particular importance, GPA and API are respectfully requesting that the Agency address the significant cost information that the Petitioners submitted for the record, including the 312-page economic analysis developed by ICF International. GPA and API hope that the Agency takes this opportunity to reconsider that cost information and demonstrate its commitment to issuing pipeline safety standards in accordance with law and respecting the rights of the Petitioners and other hardworking Americans who safely and reliably transport energy products in the nation's gas gathering lines.

GPA and API appreciate your consideration of this Petition.

Sincerely,

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BEFORE THE
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

PETITION FOR RECONSIDERATION OF "Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments"

PHMSA-2011-0023
(Nov. 15, 2021)

FILED BY

GPA MIDSTREAM ASSOCIATION
AND
AMERICAN PETROLEUM INSTITUTE

December 15, 2021

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I. SUMMARY

On November 15, 2021, the Pipeline and Hazardous Materials Safety Administration (PHMSA or the Agency) published a Final Rule in the *Federal Register*, titled "Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments" (Final Rule).[1] The Final Rule, which goes into effect on May 16, 2022, contains certain amendments to the reporting requirements and safety standards for onshore gas gathering lines in 49 C.F.R. Parts 191 and 192. GPA Midstream Association[2] (GPA) and the American Petroleum Institute[3] (API) (collectively, the Petitioners) respectfully submit this Petition for Reconsideration (Petition) of §§ 191.3, 191.15(a)(1)-(2), 191.17(a)(1)-(2), 191.23(b)(1), 192.8(a)(5), (b)-(c), 192.9(e), (f), (g), 192.13(a)(3), (b), 192.18(c), and 192.619(a)(3), (c)(2) of the Final Rule under 49 C.F.R. § 190.335.

GPA and API support the objectives of this rulemaking process; namely, establishing reasonable, risk-based safety standards for large diameter, high pressure gas gathering lines in Class 1 locations, and extending reasonable reporting requirements to all onshore gas gathering lines, whether regulated or not. The Petitioners commitment in that regard is well documented in the record of this proceeding. GPA and API have submitted numerous comment letters and participated in various meetings with PHMSA, the Gas Pipeline Advisory Committee (GPAC), and the Office of Management and Budget (OMB). To complement the Agency's rulemaking initiative, API engaged the entire stakeholder community and successfully developed two industry standards for gas gathering lines, API Recommended Practice 1182, *Construction, Operation, and Maintenance of Large Diameter Rural Gas Gathering Lines*, 1st Edition, and API Recommended Practice 80, *Definition of Onshore Gas Gathering Lines*, 2nd Edition. The Petitioners made these efforts in good faith and share PHMSA's desire to bring this decade-long proceeding to a conclusion.

Furthermore, GPA and API recognize that the issuance of the Final Rule represents an important step forward for the Agency, pipeline industry, and other interested parties. The Petitioners support several of the provisions in the Final Rule, including the general framework that PHMSA used in establishing the new safety standards in 49 C.F.R. Part 192 for gas gathering

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[1] Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, 86 Fed. Reg. 63,266 (Nov. 15, 2021) (hereinafter "Gas Gathering Final Rule").

[2] GPA Midstream has served the U.S. energy industry since 1921 and has nearly 60 corporate members that directly employ more than 56,000 employees that are engaged in a wide variety of services that move vital energy products such as natural gas, natural gas liquids (NGLs), refined products and crude oil from production areas to markets across the United States, commonly referred to as "midstream activities." The work of our members indirectly creates or impacts an additional 320,000 jobs across the U.S. economy. GPA Midstream members recover close to 90% of the NGLs such as ethane, propane, butane, and natural gasoline produced in the United States from more than 380 natural gas processing facilities. In the 2017–2019 period, GPA Midstream members spent over $50 billion in capital improvements to serve the country's needs for reliable and affordable energy.

[3] API is the national trade association representing all facets of the oil and natural gas industry, which supports 10.3 million U.S. jobs and 8 percent of the U.S. economy. API's more than 625 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. They provide most of the nation's energy and are backed by a growing grassroots movement of more than 25 million Americans.

lines in Class 1 locations that are greater than 12.75 inches in outside diameter and the new reporting requirements in 49 C.F.R. Part 191 for gas gathering lines in Class 1 and 2 locations that are not otherwise subject to regulation under Part 192.

However, the Final Rule contains requirements that are not the product of reasoned decision making, supported by substantial evidence in the record, or likely to provide any appreciable benefit to public safety. GPA and API are respectfully requesting that PHMSA reconsider those requirements for the reasons summarized below and explained in greater detail in the remainder of this Petition:

- As part of the rulemaking process, PHMSA is required to prepare a risk assessment with the reasonably identifiable or estimated costs and benefits and to consider information and comments from the public. The Agency is also required to consider the risk assessment in making a reasoned determination that the benefits of a rule justify its costs. The record shows that PHMSA ignored reasonable alternatives, relied on outdated cost information, and made other significant errors in preparing the risk assessment for the Final Rule. The record also shows that Agency failed to consider significant cost information submitted by Petitioners, including a detailed third-party economic analysis. PHMSA could not make a reasoned cost-benefit determination in light of these deficiencies.

- The effective date of the new reporting requirements in 49 C.F.R. Part 191 must be clearly aligned with the deadline in 49 C.F.R. § 192.8(b) for determining the classification of existing onshore gas gathering lines. Otherwise, operators will have reporting obligations that arise before the obligation to determine if those lines qualify as Type C or Type R lines. An exception to the safety related condition reporting requirements in 49 C.F.R. § 191.23 is also required for Type C lines that are not required to establish maximum allowable operating pressure (MAOP) under 49 C.F.R. § 192.9. The Agency acknowledged that an exception was necessary in the preamble to the Final Rule.

- The limitation for incidental gathering lines in 49 C.F.R. § 192.8(a)(5) must be amended. Section 192.8(a)(5) applies to new pipelines installed after May 16, 2022, as well as to existing pipelines that are replaced, relocated, or otherwise changed, and requires operators to treat the entire incidental gathering line as a transmission line if the pipeline extends 10 or more miles in length. Operators that repair, replace, or otherwise change existing, but previously unregulated, incidental gathering lines that meet the 10-mile threshold will have to comply with the conversion-to-service requirements in 49 C.F.R. § 192.14. Moreover, the Final Rule does not account for existing Type A, Type B, or Type C incidental gathering lines that meet the 10-mile threshold and which become regulated as transmission lines due to a repair, replacement, or other change that occurs in the future. To avoid these results, 49 C.F.R. § 192.8(a)(5) must only apply to new incidental gathering lines that are constructed entirely after May 16, 2022.

- The 6-month deadline in 49 C.F.R. § 192.8(b) for determining if existing Class 1 gas gathering lines qualify as Type C lines is unreasonable. When PHMSA established the requirements for Type A and Type B gathering lines, the Agency did not impose a strict deadline for classifying existing pipelines and allowed operators of previously unregulated lines between 18 months and 36 months to achieve compliance. The Final Rule applies to far more pipeline mileage but provides operators with far less time (6 months) to classify existing gathering lines. A reasonable compliance deadline for pipelines greater than 12.75 inches in outside diameter is May 16, 2023, and a reasonable compliance deadline for pipelines 12.75 inches or less in outside diameter is May 16, 2026. These risk-based deadlines are supported by the record and consistent with the approach that Agency used in establishing the requirements for Type A and Type B lines. To facilitate PHMSA's data collection efforts, § 192.8(b) should be amended to require existing, but previously unregulated, gas gathering lines to be treated as Type R lines until Type C status is determined.

- The criteria in 49 C.F.R. § 192.8(c) for determining whether a Class 1 gas gathering line is a Type C line must be clarified to permit the use of the default yield strength in 49 C.F.R. § 192.107(b)(2) in calculating the specified minimum yield strength (SMYS) of steel pipe. Using the default yield strength of 24,000 psi (165 MPa) in determining the design pressure of steel pipe is appropriate in cases where an operator has information about the other relevant factors, including the nominal outside diameter and wall thickness.

- The 12-month compliance deadline in 49 C.F.R. § 192.9(g) for existing Type C gathering lines is unreasonable. When PHMSA established the requirements for Type A and Type B lines, the Agency afforded operators of existing gathering lines from 18 to 36 months to achieve compliance. The Final Rule applies to far more pipeline mileage but provides operators with far less time (12 months) to achieve compliance. A reasonable compliance deadline for pipelines greater than 12.75 inches in outside diameter is May 16, 2025, and a reasonable compliance deadline for pipelines 12.75 inches or less in outside diameter is May 16, 2028. These risk-based compliance deadlines are supported by the record and consistent with the approach that PHMSA used in establishing the requirements for Type A and Type B gathering lines.

- The new requirements in 49 C.F.R. § 192.9(e)-(f) for Type C lines must be modified to provide the necessary cost-benefit justification. Pipelines 12.75 inches or less in outside diameter do not present a significant risk to public safety, and the Agency ignored substantial cost information in concluding that the benefits of applying certain requirements to these pipelines justified the costs. Damage prevention, public awareness, and emergency response are the only requirements that should apply to these small diameter Type C lines. The requirement to use leak detection equipment in conducting leakage surveys must also be removed for all Type C lines. This requirement is not supported by the cost benefit analysis and is unnecessary for identification and repair of leaks on higher stress gathering lines.

- The exception to the applicability of the design, installation, construction, initial inspection, and initial testing requirements in 49 C.F.R. § 192.9(f)(2) for Type C pipelines in existence on the effective date of the Final Rule should be increased from 40 feet to at least 500 feet. The new requirements for Type C lines should also be reorganized into a single paragraph, 49 C.F.R. § 192.9(e), to provide greater clarity and consistency with the requirements for Type A and Type B lines. Finally, the definition of building intended for human occupancy conflicts with the class location regulations in 49 C.F.R. § 192.5 and should be removed. Operators using Method 2 should also be allowed to adjust the length of the class location unit using the distances provided in the cluster rule.

II. PROCEDURAL HISTORY

A. Notice of Proposed Rulemaking

On April 8, 2016, PHMSA published a notice of proposed rulemaking (NPRM) in the *Federal Register* containing suggested changes to the safety standards and reporting requirements for onshore gas gathering lines in 49 C.F.R. Parts 191 and 192.[4] The proposed changes included repealing API Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines," 1st edition, April 2000, (RP 80), the industry standard for defining onshore gas gathering operations that is incorporated into Part 192 by reference, and adopting new definitions; applying certain safety standards to onshore gas gathering lines in Class 1 locations with a nominal outside diameter of 8 inches or greater and a MAOP producing a hoop stress of 20 percent or more of SMYS for metallic lines or more than 125 psig for non-metallic lines; and applying the reporting requirements in 49 C.F.R. Part 191 to operators of all gathering lines, whether regulated or not.[5]

1. Preliminary Regulatory Impact Analysis

PHMSA released a Preliminary Regulatory Impact Analysis (PRIA) with the NPRM that evaluated the potential costs and benefits of the proposed rule.[6] In the PRIA's problem statement, the Agency explained that additional regulations were needed due to the increase in larger diameter, higher pressure gas gathering lines.[7] PHMSA stated that these gathering lines exceeded

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[4] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722 (Apr. 8, 2016).
[5] *Id.* at 20,827-20,828. As the primary support for these proposals, PHMSA pointed to recent changes in the operating parameters of gas gathering lines in the nation's shale plays, as well as concerns with the enforcement and application of API RP 80. *Id.* at 20,801-20,808. PHMSA also asserted that its proposals were consistent with a 2010 National Association of Pipeline Safety Representatives resolution and more recent U.S. Government Accountability Office recommendations relating to gas gathering lines. *Id.* at 20,808; PHMSA, Preliminary Regulatory Impact Assessment at 101 (Mar. 2016) (hereinafter "PRIA"), https://www.regulations.gov/document?D=PHMSA-2011-0023-0117. *See* U.S. Gov't Accountability Off., GAO-12-388, PIPELINE SAFETY: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety (Mar. 2012), https://www.gao.gov/assets/gao-12-388.pdf; U.S. Gov't Accountability Off., GAO-14-667, OIL AND GAS TRANSPORTATION: Department of Transportation Is Taking Actions to Address Rail Safety, but Additional Actions Are Needed to Improve Pipeline Safety (Aug. 2014), https://www.gao.gov/assets/gao-14-667.pdf.
[6] PRIA at 27.
[7] *Id.* 101.

historical design and operating parameters, creating the need for additional safety requirements and data collection.[8]

After stating that the impact of the proposed regulations would be "limited to higher-risk lines (*i.e.*, larger lines that operate at higher pressures) and the most likely causes . . . of pipeline failure [(corrosion and excavation damage)],"[9] the Agency estimated that the average annualized safety and environmental benefits of its proposals would be $11.3 million[10] and that the average annualized costs would be $12.6 million.[11] These estimates included the cost of benefits of both extending safety requirements and repealing the gathering line exception from reporting requirements.

According to the PRIA, the Agency considered two groups of operators in estimating the potential costs of the NPRM: (1) operators that currently have regulated pipeline facilities and (2) operators that do not currently have regulated pipeline facilities.[12] PHMSA assumed that the NPRM would impose fewer costs on the former group of operators, which would presumably already have regulatory compliance programs in place and might be applying safety practices to unregulated Class 1 gathering lines on a voluntary basis.[13] PHMSA acknowledged that its cost estimates were based on a 2006 study by the Independent Petroleum Association of America (IPAA).[14]

In identifying the potential benefits of the NPRM, PHMSA stated that there would be a reduction in the potential for corrosion and excavation damage incidents, which are the leading causes of pipeline incidents.[15] The Agency estimated, based on incident data from regulated gathering lines in Class 2, 3, and 4 locations and transmission lines in Class 1 and 2 locations, that the expanded regulations would result in avoided incidents valued at an average $9.7 million annually,[16] and estimated the environmental benefits would be $1.6 million annually.[17]

With regard to alternatives to the expanded safety regulations, PHMSA said it considered applying safety regulations to all unregulated lines, but decided against that approach given the substantial costs and fewer benefits associated with regulating the additional mileage (*i.e.*, smaller, lower pressure, and more rural lines).[18] The Agency did not consider any other alternatives in the PRIA, such as regulating only those Class 1 gathering lines with larger diameters (*e.g.*, only those greater than 12.75 or 16 inches in outside diameter).

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8 *Id.*
9 *Id.* at 102.
10 *Id.* at 151 (using a 7% discount rate).
11 *Id.* at 7, 117 (using a 7% discount rate).
12 *Id.* at 102.
13 *Id.*
14 *Id.* at 103.
15 *Id.* at 144.
16 *Id.* at 147.
17 *Id.* at 151.
18 *Id.* at 152.

2. Industry Comments

The Petitioners and other industry stakeholders submitted detailed comments in response to the NPRM.[19] The industry commenters generally stated that the new definitions would adversely impact producers and gatherers by extending the Agency's jurisdiction closer to the wellhead and requiring the widespread reclassification of pipeline facilities. The industry commenters also stated that PHMSA's proposal to extend Part 192 requirements to onshore gas gathering lines as small as 8 inches in outside diameter was unjustified and would impose undue economic burdens. The industry commenters specifically indicated that the PRIA significantly underestimated the costs—and significantly overestimated the benefits—of the proposed rule.

For example, GPA stated that the Agency's proposal would likely "result in little or no safety benefit" and included "provisions that may be impracticable to implement."[20] GPA also commented that the actual total costs of PHMSA's proposal would far exceed the $12.6 million annual cost to industry asserted by PHMSA.[21] Throughout its comments, GPA noted certain costs of compliance with the proposed regulations that were not either considered in the PRIA or were grossly underestimated.[22] GPA maintained that the costs of compliance with the proposed regulations would be more reasonable if PHMSA used a higher diameter threshold for determining regulated gathering lines.[23]

API emphasized in its comments that PHMSA grossly underestimated the costs of the proposed rule while overestimating the benefits.[24] In support of that position, API submitted a detailed economic analysis that ICF International (ICF) prepared after reviewing the NPRM.[25] ICF's analysis indicated that the total costs of the NPRM would far exceed PHMSA's estimates, *i.e.*, ICF estimated the NPRM would cost industry $28 billion over the initial 15-year compliance period, as compared to PHMSA's estimate of $189 million. ICF identified various errors and omissions in the PRIA, including PHMSA's failure to include all of the costs of compliance and to properly estimate the costs associated with the new safety and reporting requirements.[26] ICF further found that PHMSA's assumptions regarding costs to operators with existing regulated assets to be inaccurate and the incident data that the Agency relied upon to be flawed.[27] ICF's analysis showed that the NPRM would have a disproportionate impact on small operators as well,

[19] Comments of GPA Midstream Ass'n, Docket No. PHMSA-2011-0023 (July 7, 2016) (hereinafter "GPA 2016 Comments"), https://www.regulations.gov/document?D=PHMSA-2011-0023-0290; Comments of American Petroleum Institute, Docket No. PHMSA-2011-0023 (July 7, 2016), (hereinafter "API 2016 Comments"), https://www.regulations.gov/document?D=PHMSA-2011-0023-0381.
[20] GPA 2016 Comments at 2.
[21] *Id.*
[22] *Id.* at 5, 8, 23 (including costs associated with public awareness programs, emergency response, operator qualification, establishing MAOP, reporting costs, administrative costs, pipe replacement costs, corrosion control costs).
[23] *Id.* at 25.
[24] API 2016 Comments at 2, 16-17.
[25] API 2016 Comments at 2.
[26] ICF International, Cost and Benefit Impact Analysis of the PHMSA Natural Gas Gathering and Transmission Safety Regulation Proposal at 2-3 (hereinafter "API 2016 ICF Study"), https://www.regulations.gov/comment/PHMSA-2011-0023-0381.
[27] *Id.*

leading to annual compliance costs that would consume about 90% of the revenue generated by small gathering companies.[28]

3. Other Industry Efforts

To complement PHMSA's rulemaking process, API began an effort in January 2018 to develop additional industry standards for gas gathering lines. The first effort involved creating a new recommended practice for the design, construction, testing, operation, and maintenance of larger diameter, higher stress gas gathering lines in Class 1 locations. The second effort involved updating an existing recommended practice for defining onshore gas gathering lines. Representatives from a range of stakeholder groups participated in the standards development process, including API and GPA member companies, PHMSA and state pipeline safety authorities, and environmental and other advocacy organizations. Both efforts concluded with API's successful publication of recommended practices, API Recommended Practice 1182, *Construction, Operation, and Maintenance of Large Diameter Rural Gas Gathering Lines*, 1st Edition (Mar. 2020) and API Recommended Practice 80, *Definition of Onshore Gas Gathering Lines*, 2nd Edition (Mar. 2020).

At PHMSA's request, in September 2018 GPA, API, and another industry trade organization also provided a detailed briefing to the GPAC. The GPAC is a 15-person federal advisory committee charged with reviewing and providing PHMSA with recommendations on "the technical feasibility, reasonableness, cost-effectiveness, and practicability" of proposed changes to the gas pipeline safety regulations.[29] During that briefing, GPA, API, and the other attendees shared information about the midstream industry, the history, design, construction, and operation of gas gathering lines, and the critical role that these pipelines serve in the energy transportation sector.

B. Gas Pipeline Advisory Committee Meeting

In December 2018, PHMSA released a modified version of the NPRM's proposals for consideration by the GPAC.[30] Acknowledging the comments previously received, the modified

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[28] *Id.* at 6.

[29] 49 U.S.C. § 60115(c)(2).

[30] PHMSA, Safety of Gas Gathering Pipelines, GPAC Meeting at 80 (Jan. 8-9, 2019) (GPAC Presentation), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/standards-rulemaking/pipeline/70276/gas-gathering-lines-gpac-meeting-jan-8-9-2019-presentation-version-12-21-2019.pdf. In early December 2018, Petitioners filed a joint position paper with PHMSA in anticipation of the GPAC's review of the NPRM. API and GPA, Joint Position Paper, Docket No. PHMSA-2011-0023 (Dec. 4, 2018), https://www.regulations.gov/document?D=PHMSA-2011-0023-0452; API and GPA, Joint Clarification Letter, Docket No. PHMSA-2011-0023 (Dec. 6, 2018), https://www.regulations.gov/document?D=PHMSA-2011-0023-0454. Petitioners reiterated that they did not support repealing RP 80 and adopting new gathering definitions. Petitioners also expressed support for extending certain safety standards to Class 1 gathering lines but asked PHMSA to limit those provisions to higher-stress pipelines greater than 16 inches in diameter and to incorporate other risk-based concepts to make the regulations more efficient and cost effective. GPA submitted a separate letter on the latter point urging PHMSA to provide an exception for Class 1 gas gathering lines that did not contain any buildings intended for human occupancy or identified sites within the PIR. GPA Supplemental Position Paper on "Pipeline Safety: Safety of Gas Gathering Pipelines," RIN 2137-AF38 (Dec. 4, 2018). Finally, Petitioners asked PHMSA to limit the applicability of the federal reporting requirements for unregulated Class 1 gathering lines to incident and annual reports only.

proposal recommended that the proposed changes to the gas gathering definitions be withdrawn; that the minimum diameter threshold for regulated Class 1 gas gathering lines be increased from 8 inches or greater to greater than 12 inches;[31] and that at least one dwelling be located within the potential impact radius (PIR) for pipelines at the lowest end of the diameter threshold (greater than 12 inches and less than or equal to 16 inches) to be regulated. As for the other aspects of the NPRM, PHMSA recommended that the requirements for Type B gathering lines and the emergency response provisions in 49 C.F.R. § 192.615 apply to regulated Class 1 gas gathering lines; that operators of existing regulated Class 1 gas gathering lines be given two years to achieve compliance with those regulations; and that a "letter of no objection" process be added to allow for the continued use of composite pipe in regulated systems. Lastly, the Agency recommended that operators of regulated Class 1 gas gathering lines comply with the same Part 191 reporting requirements as operators of other regulated gathering lines; but that operators of unregulated Class 1 gas gathering lines only comply with the incident and annual reporting requirements in Part 191, and that the annual reporting form for unregulated Class 1 gas gathering lines be modified to only require certain specific information.[32]

On June 25 and 26, 2019, the GPAC met to consider the Agency's modified proposal.[33] During that meeting, the GPAC endorsed PHMSA's recommendations to retain the current gathering definitions and limit the federal reporting requirements for unregulated Class 1 gas gathering lines to incident and annual reporting only. However, the GPAC recommended that PHMSA consider establishing a minimum set of safety standards for Class 1 gas gathering lines 8 inches or greater in diameter, and that the Agency use a PIR concept in determining whether additional safety standards should apply to larger diameter gathering lines, *e.g.*, greater than 12 inches in diameter. The GPAC did not consider the PRIA (or any of the evidence in the record disputing the methodology and merits of that assessment) in making either of the latter recommendations.[34]

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[31] GPAC Presentation at 93. PHMSA said that the comments received in response to the NPRM indicated that a minimum nominal diameter threshold of greater than 12 inches would be sufficient to capture the larger diameter, higher pressure associated with unconventional shale gas production. *Id.* at 94.

[32] In early June 2019, Petitioners submitted another joint comment letter responding to PHMSA's GPAC proposal. Petitioners expressed strong support for the Agency's recommendation to retain the current gathering definitions. Petitioners also expressed support for increasing the minimum diameter threshold for regulated Class 1 gas gathering lines to greater than 12 inches and adding a PIR exception (although GPA asked PHMSA to remove the 16-inch-diameter limitation and apply the latter provision to pipelines 24 inches or less in diameter). Petitioners expressed general support for applying the requirements for Type B gathering lines and emergency plans to regulated Class 1 gas gathering lines, so long as the Agency took appropriate action to accommodate the use of composite pipe materials and extended the compliance deadlines for certain provisions. Finally, Petitioners expressed general support for extending the federal incident and annual reporting requirement to unregulated Class 1 gas gathering lines. API and GPA, Supplemental Comment Letter PHMSA GPAC Presentation, Docket. No. PHMSA-2011-0023 (Jun. 10, 2019) https://www.regulations.gov/document?D=PHMSA-2011-0023-0460.

[33] GPAC Meeting (June 25-26, 2019), https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=143. As a result of an unexpected lapse in federal government funding, PHMSA had to postpone the GPAC meeting from early January 2019 until late June 2019.

[34] Petitioners submitted another supplemental comment letter to PHMSA following the GPAC meeting. Supplemental Comment of GPA and API on "Pipeline Safety: Safety of Gas Gathering Pipelines," RIN 2137-AF38, June 2019 Gas Pipeline Advisory Committee Meeting (Sept. 30, 2019). In that joint letter, Petitioners urged PHMSA to accept the GPAC's recommendation to retain the existing definitions for onshore gas gathering lines and to regulate only Class 1 gas gathering lines greater than 12 inches in diameter. However, Petitioners urged PHMSA to reject the GPAC's recommendation to consider establishing new safety standards for Class 1 gathering lines that are 12-inches or less in

C. Office of Information and Regulatory Affairs Review

On August 31, 2021, PHMSA sent a draft version of the Final Rule to the Office of Information and Regulatory Affairs (OIRA) within OMB[35] for review pursuant to Executive Order 12866,[36] as amended.[37] Petitioners requested separate meetings with OIRA to discuss the Final Rule, which occurred on October 4 and 5, 2021, respectively.[38] API and GPA both reiterated their longstanding concerns with the PRIA during these meetings and the absence of an adequate cost-benefit justification for applying Part 192 requirements to smaller diameter gas gathering lines. On November 2, 2021, one day after being returned by OMB with minor revisions,[39] PHMSA released a pre-publication version of the Final Rule.[40]

D. Final Rule

On November 15, 2021, PHMSA published the Final Rule in the *Federal Register*. The Final Rule amended 49 C.F.R. Parts 191 and 192 in the following respects, effective as of May 16, 2022.

- The Final Rule creates a new category of regulated onshore gas gathering lines known as Type C lines. Type C lines include onshore gas gathering lines in Class 1 locations with an outside diameter greater than or equal to 8.625 inches and an MAOP that produces a hoop stress of 20 percent or more of SMYS for metallic lines, or more than

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diameter, explaining that "there is no data to suggest that these lines present a sufficient risk to public safety to warrant regulation, nor is there any indication that the benefits of applying the proposed safety standards to these lines would justify the costs." *Id.* at 7. Petitioners also asserted that the GPAC failed to meet its statutory obligation to prepare and submit a report on the "'technical feasibility, reasonableness, cost-effectiveness, and practicability' of the proposed standard" and include in the report recommended actions within 90 days of receiving the proposed standard and supporting analyses from PHMSA. *Id.* at 9 (quoting 49 U.S.C. § 60115(c)(2)). Finally, Petitioners stated that the GPAC failed to consider the cost effectiveness of the proposed regulations, including failing to review the PRIA or public comments challenging the PRIA.

[35] PIPES Act 2020 Web Chart (Nov. 10, 2021), https://www.phmsa.dot.gov/legislative-mandates/pipes-act-web-chart (OPS: Safety of Gas Gathering Pipelines).

[36] Executive Order No. 12866, Regulatory Planning and Review, 58 Fed. Reg. 51,735 (Oct. 4, 1993).

[37] *See* Executive Order No. 13258, Amending Executive Order 12866 on Regulatory Planning and Review, 67 Fed. Reg. 9,385 (Feb. 28, 2002) and Executive Order No. 13422, Further Amendment to Executive Order 12866 on Regulatory Planning and Review, 72 Fed. Reg. 2,763 (Jan. 23, 2007).

[38] EO12866 Meeting Summary – Gas Gathering – API (Oct. 4, 2021), https://www.regulations.gov/document/PHMSA-2011-0023-0482; EO 12866 Meeting Summary – Gas Gathering – GPA (Oct. 5, 2021) https://www.regulations.gov/document/PHMSA-2011-0023-0483.

[39] https://www.reginfo.gov (Office of Information and Regulatory Affairs Executive Order Reviews Completed between January 01, 2021 to November 30, 2021).

[40] Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2021-11/Gas%20Gathering%20Final%20Rule%20Submission%20-%2011.2.2021.pdf. PHMSA's release of the Final Rule was apparently timed to coincide with the release of a separate rulemaking proposal from the U.S. Environmental Protection Agency and other federal actions targeting potential reductions in methane emissions that U.S. officials highlighted while attending the 2021 United Nations Climate Change Conference in Glasgow, Scotland. Dino Grandoni and Steven Mufson, *Biden unveils new rules to curb methane, a potent greenhouse gas, from oil and gas operations*, Washington Post (Nov. 2, 2021), https://www.washingtonpost.com/climate-environment/2021/11/02/biden-methane-rule-epa/

125 psig for non-metallic lines or metallic lines if the stress level is unknown. Operators of Type C lines are subject to the same Part 191 requirements as Type A and Type B lines and must comply with certain Part 192 requirements for gas transmission lines. Operators of Type C lines in existence on or before May 16, 2022, that were not previously regulated must comply with all applicable requirements within 1 year, or on or before May 16, 2023, but may request an alternative compliance deadline.

- The Final Rule also creates a new category of reporting-only regulated gathering lines known as Type R lines. Type R lines include any onshore gas gathering lines that do not meet the definition of a Type A, Type B, or Type C line. Operators of Type R lines must comply with the incident and annual reporting requirements in Part 191 using a modified form. The amendments to Part 191 go into effect on May 16, 2022.

- The Final Rule contains additional amendment to Part 192. One of those amendments requires operators of gathering lines to establish records of the beginning and endpoints of gathering lines by November 16, 2022, subject to a request for an alternative compliance deadline. Another amendment imposes a 10-mile limit on the use of the incidental gathering designation for pipelines that are new, replaced, relocated, or otherwise changed. Finally, the Final Rule authorizes the use of composite materials in new or replaced Type C lines if certain requirements are met.

The Agency released the Final Regulatory Impact Analysis (FRIA) with the Final Rule, which provided "an assessment of the benefits (including safety and environmental benefits) and costs of the final rule as well as reasonable alternatives."[41] The FRIA estimated that the Final Rule will impact approximately 426,000 miles of gas gathering lines that have historically been excluded from regulation, of which 91,000 miles will be subject to new safety requirements.[42] According to the FRIA, PHMSA determined that the Final Rule:

> (1) has benefits that justify its costs; (2) is a "significant regulatory action" as defined in section 3(f) of Executive Order 12866, (3) would not have a significant economic impact on a substantial number of small entities; (4) would not constitute an unfunded mandate; (5) would not have Federalism implications because it does not impose substantial direct compliance costs on State or local governments; [sic] and (6) satisfies the risk-assessment requirements of 49 U.S.C. 60102(b)(2)(d), 60102(b)(2)(e), and 60102(b)(3).[43]

PHMSA estimated that the annualized costs of compliance with the Final Rule would be $13.7 million per year.[44] PHMSA's cost calculations are based on information provided by the IPAA in 2006.[45] PHMSA stated that IPAA's data "was the best available information for many

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[41] Gas Gathering Final Rule, 86 Fed. Reg. at 63,286.
[42] PHMSA, Regulatory Impact Analysis, Pipeline Safety: Expansion of Gas Gathering Regulation Final Rule at 3, 5 (Nov. 2021) (hereinafter "FRIA"), https://www.regulations.gov/document/PHMSA-2011-0023-0488.
[43] *Id.* at 4.
[44] Gas Gathering Final Rule, 86 Fed. Reg. at 63,268; FRIA at 5.
[45] FRIA at 16.

of the cost estimates for this rule."[46] The Agency included the following chart in estimating the costs associated with the major provisions of the Final Rule.[47]

Provision	**Estimated Annualized Cost (7%)**
Right-of-Way Surveillance	$170,087
Corrosion Control	$2,043,260
Damage Prevention	$285,011
Public Awareness	$550,464
Line Markers	$1,680,870
Emergency Plan	$312,167
Leakage Surveys	$7,626,075
Incident reporting	$134,556
Annual reporting	$943,408
Construction	Negligible
Total	**$13,745,898**

PHMSA stated that it "expects benefits of the final rule to consist of improved safety and avoided environmental harms (including methane emissions) from reduction of the frequency and consequences of failures of onshore natural gas gathering lines that could result in releases and incidents."[48] PHMSA stated that the avoided failures will result in "avoided deaths, injuries, evacuations, commodity loss, repairs, and environmental damages."[49] In citing the lack of incident data from gathering lines, PHMSA relied on transmission line incident data to project the benefits of the Final Rule.[50] However, the Agency concluded that it could not estimate the total value of the benefit given that it did not have a projection of the number of incidents that would be avoided due to the Final Rule.[51] Other benefits of the Final Rule, PHMSA said, include emissions reductions from avoided natural gas releases, decreased supply disruptions, and improved reporting.[52] However, given that the Agency did not have data on the magnitude of gas release during gathering line incidents, it could not estimate the value of reduced emissions.[53]

PHMSA noted in the Final Rule that GPA raised concern with the proposed reporting requirements, but the Agency did not respond in any way to those comments.[54] The Agency also stated that Petitioners, along with other commenters, "submitted comments noting issues and uncertainty with the regulatory impact assessment."[55] Specifically, PHMSA noted that GPA commented "that the cost analysis underestimated the time and cost to identify newly regulated gathering lines in a short amount of time and comply with the new requirements, especially MAOP determination and public awareness."[56] The Agency also noted that Petitioners commented that

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[46] *Id.*
[47] Gas Gathering Final Rule, 86 Fed. Reg. at 63,268; FRIA at 4.
[48] Gas Gathering Final Rule, 86 Fed. Reg. at 63,286; *see also* FRIA at 4.
[49] FRIA at 32.
[50] *Id.* at 31.
[51] *Id.* at 32.
[52] *Id.* at 5.
[53] *Id.* at 32.
[54] Gas Gathering Final Rule, 86 Fed. Reg. at 63,274.
[55] *Id.* at 63,279.
[56] *Id.*

"the compliance cost estimates used in the RIA for . . . Type C . . . regulated gathering lines were underestimated and contained erroneous assumptions."[57] PHMSA did not respond to these concerns in any meaningful or significant way, except to say that "[i]n response to comments and additional analysis, PHMSA has also updated the RIA. The revisions and clarifications [to the Final Rule] reduce the cost of the requirements in § 192.9."[58] The Agency also asserted that "clarifying that the recordkeeping, material verification, and MAOP reconfirmation requirements proposed in the NPRM were not intended to apply to gathering or distribution lines addresses a large share of the cost concerns raised in the comments."[59]

Concerning the requirements of Executive Order 12866, PHMSA explained in the Final Rule that the Agency "sought public comment on the proposals in the NPRM (including preliminary cost and cost savings analyses pertaining to those proposals), as well as any information that could assist in evaluating the benefits and costs of this rulemaking. Those comments are addressed, and additional discussion about the economic impacts of the final rule are provided, within the final regulatory impact analysis (RIA) posted in the docket."[60] As for the requirements in the Regulatory Flexibility Act, PHMSA summarily stated that the economic impact on small entities would be limited "as the annualized costs of the final rule represent only approximately 0.1 percent of annual industry revenues for the entire crude oil transportation industry . . . illustrating the minor financial impact on firms operating within this space."[61]

III. LEGAL FRAMEWORK

The Pipeline Safety Act provides PHMSA with the authority to prescribe minimum safety standards for pipeline transportation and for pipeline facilities.[62] Each standard must be practicable and designed to meet the need for gas pipeline safety and protection of the environment.[63] When prescribing a standard, the Pipeline Safety Act requires PHMSA to consider certain factors, including:

> (A) relevant available—(i) gas pipeline safety information; (ii) hazardous liquid pipeline safety information; and (iii) environmental information; (B) the appropriateness of the standard for the particular type of pipeline transportation or facility; (C) the reasonableness of the standard; (D) **based on a risk assessment, the reasonably identifiable or estimated benefits** expected to result from implementation or compliance with the standard; (E) **based on a risk assessment, the reasonably identifiable or estimated costs** expected to result from implementation or compliance with the standard; (F) **comments and information received from the public**; and (G) the comments and recommendations of the Technical Pipeline Safety Standards Committee, the Technical Hazardous Liquid Pipeline Safety Standards Committee, or both, as appropriate.[64]

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[57] *Id.* at 63,281.
[58] *Id.* at 63,286.
[59] *Id.* at 63,286-87.
[60] *Id.* at 63,291.
[61] *Id.* at 63,292.
[62] 49 U.S.C. § 60102(a)(2).
[63] 49 U.S.C. § 60102(b).
[64] 49 U.S.C. § 60102(b)(2)(A)-(G) (emphasis added).

As discussed in more detail below, PHMSA failed to conduct the required cost benefit analysis and address comments and information received from the public in promulgating the Final Rule.

A. The Pipeline Safety Act Requires PHMSA to Make a Reasoned Determination that the Benefits of a Rule Justify Its Costs

Section 60102(b)(5) of the Pipeline Safety Act states that PHMSA "shall propose or issue a standard under this chapter only upon a reasoned determination that the benefits, including safety and environmental benefits, of the intended standard justify its costs."[65] It further states that the Agency "shall consider . . . based on a risk assessment, the reasonably identifiable or estimated benefits [and costs] expected to result from implementation or compliance with the standard."[66] In conducting the risk assessment, PHMSA must:

> (A) identify the regulatory and nonregulatory options that [PHMSA] considered in prescribing a proposed standard; (B) identify the costs and benefits associated with the proposed standard; (C) include—(i) an explanation of the reasons for the selection of the proposed standard in lieu of the other options identified; and (ii) with respect to each of those other options, a brief explanation of the reasons that [PHMSA] did not select the option; and (D) identify technical data or other information upon which the risk assessment information and proposed standard is based.[67]

PHMSA must provide "the risk assessment information and other analyses supporting each proposed standard" to the Pipeline Advisory Committee, the federal advisory committee that reviews and provides recommendations on pipeline safety rulemaking proposals.[68] The Pipeline Advisory Committee is then required to "prepare and submit to [PHMSA] a report on the technical feasibility, reasonableness, cost-effectiveness, and practicability of the proposed standard and include in the report recommended actions" within 90 days of receiving the proposed standard and supporting analyses.[69] The Agency is required to "publish each report, including any recommended actions and minority views." PHMSA is "is not bound by the conclusions of the

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[65] 49 U.S.C. § 60102(b)(5). The Pipeline Safety Act recognizes three exceptions to the cost-benefit determination that PHMSA is required to make in a rulemaking proceeding. None of those exceptions appears to apply to the final rule for onshore gas gathering lines. *Id.* § 60102(b)(6) ("Exceptions from application.—The requirements of subparagraphs (D) and (E) of paragraph (2) do not apply when— (A) the standard is the product of a negotiated rulemaking, or other rulemaking including the adoption of industry standards that receives no significant adverse comment within 60 days of notice in the Federal Register; (B) based on a recommendation (in which three-fourths of the members voting concur) by the Technical Pipeline Safety Standards Committee, the Technical Hazardous Liquid Pipeline Safety Standards Committee, or both, as applicable, the Secretary waives the requirements; or (C) the Secretary finds, pursuant to section 553(b)(3)(B) of title 5, United States Code, that notice and public procedure are not required.").

[66] *Id.* § 60102(b)(2)(D), (E).

[67] *Id.* § 60102(b)(3).

[68] *Id.* § 60115(c)(1)(A).

[69] *Id.* § 60115(c)(2).

[Pipeline Advisory Committee]" on a proposed rule but must "publish the reasons" for rejecting its conclusions.[70]

Congress added the requirement to consider cost-effectiveness in promulgating new regulations as part of the Accountable Pipeline Safety and Partnership Act of 1996.[71] The fundamental purpose of the provision was to "ensure that most safety and environmental risks are addressed with the most cost-effective solutions," and to "identify the most rational, cost-effective alternatives, if any, to a given proposed safety requirement."[72] Congress explained that the risk assessment "would identify or estimate the benefits expected to result from a proposed standard, as well as identify or estimate the expected costs to result from the proposed standard" and would complement PHMSA's existing risk assessment prioritization model.[73] Congress also added the requirement for peer review of proposed standards by the Pipeline Advisory Committee "to bring more rationality to federal pipeline safety standard setting and broaden participation by requiring [Office of Pipeline Safety] to consider more carefully comments received from these bodies."[74]

B. The Administrative Procedure Act Requires Agency Actions to be the Product of Reasoned Decision Making and Supported by Substantial Evidence in the Record

The Administrative Procedure Act (APA) requires agency actions to be the product of reasoned decision making and supported by substantial evidence in the record. In the rulemaking context, a cost-benefit analysis must show a "rational connection between the facts found and the choice made"[75] and be "based on a consideration of the relevant factors."[76] In other words, an agency must engage in reasoned decision making and reach reasonable conclusions.[77] A cost-benefit analysis that fails to meet these standards provides a basis for invalidating a final rule.[78]

When an agency such as PHMSA is required by law to use a cost-benefit analysis in promulgating regulations, particular focus is paid to statutorily-mandated factors in evaluating reasonableness and adequacy.[79] Agencies must provide equal treatment to identifying the costs

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[70] *Id.*
[71] Pub. L. No. 104-304, §§ 4, 10, 110 Stat. 3793, 3794, 3801-02 (1996).
[72] Report of the Committee on Commerce, Science, and Transportation on S. 1505, S. Rept. 104-334 at 2-3 (July 26, 1996).
[73] *Id.* at 3.
[74] *Id.* at 3-4.
[75] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)); *Pub. Citizen v. Federal Motor Carrier Safety Admin.*, 374 F.3d 1209, 1216 (D.C. Cir. 2004).
[76] *State Farm,* 463 U.S. at 43; *Bowman Transp., Inc. v. Arkansas-Best Freight System, Inc.*, 419 U.S. 281 (1974).
[77] *State Farm,* 463 U.S. at 43; *City of Portland v. EPA*, 507 F.3d 706, 713 (D.C. Cir. 2007).
[78] 5 U.S.C. § 706(2)(A). *See also Weyerhaeuser Co. vs. U.S. Fish & Wildlife Serv.*, 139 S. Ct. 361, 371 (2018); *Nat'l Ass'n of Home Builders v. EPA*, 682 F.3d 1032, 1039 (D.C. Cir. 2012); *City of Portland*, 507 F.3d at 712-713; *Ctr. For Auto Safety v. Peck*, 751 F.2d 1336, 1370 (D.C. Cir. 1985); *Am. Textile Mfrs. Institute v. Donovan,* 452 U.S. 490, 528-529 & n. 52 (1981).
[79] *See, e.g., Business Roundtable v. SEC*, 647 F.3d 1144, 1148-49 (D.C. Cir. 2011)

and benefits of a regulation,[80] and consider all relevant categories of costs and benefits.[81] Where costs are unknown or vary, agencies are expected to use their expertise to estimate the costs.[82] Agencies are further expected to evaluate less burdensome and less costly regulatory alternatives.[83] And, an agency's choice of model and methodology must bear a "rational relationship to the characteristics of the data to which it is applied."[84]

Cost benefit analyses may be found arbitrary and capricious where "the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise."[85]

C. The Administrative Procedure Act and Pipeline Safety Act Require PHMSA to Respond to Significant Comments Submitted During the Rulemaking Process

The APA requires agencies to "consider and respond to significant comments received during the period for public comment," including by examining the relevant data and articulating an explanation in response to comments that, if adopted, would require a change to the final rule.[86] The Pipeline Safety Act also requires PHMSA to consider "comments and information received from the public" in deciding whether to promulgate a new safety requirement.[87] The D.C. Circuit Court of Appeals recently explained that "an agency must respond to comments 'that can be thought to challenge a fundamental premise' underlying the proposed agency decision."[88] Further, "[a]n agency's response to public comments . . . must be sufficient to enable the courts 'to see what major issues of policy were ventilated . . . and why the agency reacted to them as it did.'"[89]

D. Petition for Reconsideration Standard

The Pipeline Safety Regulations at 49 C.F.R. § 190.335 provide that "any interested person may petition the Associate Administrator for reconsideration of any regulation."[90] The petition must be received no later than 30 days after the rule is published in the Federal Register.[91]

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[80] *See, e.g. id.*; *Ctr for Biological Diversity v. NHTSA*, 538 F.3d 1172 (9th Cir. 2008); *Sierra Club v. Sigler*, 695 F.2d 957 (5th Cir. 1983); *Corrosion Proof Fittings v. EPA*, 947 F.2d 1201 (5th Cir. 1991).
[81] *See, e.g., Business Roundtable*, 647 F.3d at 1148-49.
[82] *Pub. Citizen*, 374 F.3d at 1221; *Consumer Elec. Ass'n v. FCC*, 347 F.3d 291, 302 (D.C. Cir. 2003).
[83] *Corrosion Proof Fittings*, 947 F.2d at 1216-17.
[84] *Nat'l Wildlife Federation v. EPA*, 286 F.3d 554 (D.C. Cir. 2002) (quoting *Appalachian Power Co. v. EPA*, 135 F.3d 791, 802 (D.C. Cir. 1998)).
[85] *State Farm*, 463 U.S. at 43; *Huawei Technologies USA, Inc. v. FCC*, 2 F.4th 421, 452 (5th Cir. 2021).
[86] *Perez v. Mortgage Bankers Ass'n*, 575 U.S. 92, 96 (2015); *Carlson v. Postal Reg. Comm'n*, 938 F.3d 337, 343 (D.C. Cir. 2019); *Altera Corp. & Subsidiaries v. IRS*, 926 F.3d 1061, 1080-81 (9th Cir. 2019); *La. Fed. Land Bank Ass'n, FCLA v. Farm Credit Admin.*, 336 F.3d 1075, 1080 (D.C. Cir. 2003); *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 393-94 (D.C. Cir. 1973),
[87] 49 U.S.C. § 60102(b)(2)(F).
[88] *Carlson*, 938 F.3d at 344 (quoting *MCI WorldCom, Inc. v. FCC*, 209 F.3d 760, 765 (D.C. Cir. 2000)).
[89] *Id.* (citing *Del. Dep't of Nat. Res. & Env't Control v. EPA*, 785 F.3d 1, 17 (D.C. Cir. 2015)).
[90] 49 C.F.R. § 190.335(a).
[91] *Id.*

PHMSA's rules require that the petition "contain a brief statement of the complaint and an explanation as to why compliance with the rule is not practicable, is unreasonable, or is not in the public interest."[92] And, "[i]f the petitioner requests the consideration of additional facts, the petitioner must state the reason they were not presented to the Associate Administrator or the Chief Counsel within the prescribed time."[93]

In response, the Associate Administrator "may grant or deny, in whole or in part, any petition for reconsideration without further proceedings, except where a grant of the petition would result in issuance of a new final rule. In the event that the Associate Administrator . . . determines to reconsider any regulation, a final decision on reconsideration may be issued without further proceedings, or an opportunity to submit comment or information and data as deemed appropriate, may be provided."[94] PHMSA's rules provide that its policy is to issue "notice of the action taken on a petition for reconsideration within 90 days after the date on which the regulation in question is published in the Federal Register."[95]

IV. RECONSIDERATION

Petitioners respectfully request that PHMSA reconsider certain requirements in the Final Rule that are not the product of reasoned decision making or supported by substantial evidence in the record. As discussed in more detail below, PHMSA failed to comply with the requirements in the Pipeline Safety Act and APA in promulgating the Final Rule in several respects. The Agency did not consider the significant cost information submitted by Petitioners or prepare an adequate risk assessment. PHMSA also ignored reasonable alternatives, relied on outdated cost information, and made other errors in evaluating the costs and benefits of the Final Rule.[96] In short, reconsideration is warranted because the Agency did not make the reasoned determination required under the Pipeline Safety Act and APA in developing the requirements in the Final Rule.[97]

A. PHMSA Failed to Meet its Statutory Obligations in Promulgating the Final Rule

The Pipeline Safety Act requires PHMSA not only to consider comments and information provided in the rulemaking processes, but to make a reasoned determination that the benefits of the intended standard justify the costs.[98] PHMSA did neither when promulgating the Final Rule.

1. PHMSA Failed to Consider Significant Cost Information Submitted by Petitioners in Promulgating the Final Rule

Petitioners' comments and cost data submitted in response to the NPRM challenged the fundamental underpinnings of the proposed regulations. Yet, PHMSA did not recognize or

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[92] *Id.*
[93] *Id.* § 190.335(b).
[94] *Id.* § 190.337(a).
[95] *Id.* § 190.337(b).
[96] 49 U.S.C. § 60102(b)(3).
[97] *Id.* § 60102(b)(5).
[98] *Id.* § 60102(b)(3), (b)(5)

significantly address these comments in the Final Rule or FRIA.[99] Petitioners' comments raised significant concerns with the Agency's cost benefit analysis, including that PHMSA failed to consider all of the costs of compliance, that the cost estimates were inaccurate, that the PRIA understated the impact to operators, and that the PRIA overstated the benefits.[100] API's independent economic analysis put forth significant cost data that called into questions PHMSA's PRIA, and similarly calls into question the FRIA.[101]

PHMSA completely overlooked the Petitioners comments raising concerns with the costs of the Final Rule. The Agency merely noted that industry commenters expressed concern with the costs of compliance with the proposed regulations, without providing any articulated reason or justification for not evaluating those comments and cost data.[102] There is no avenue for a court or interested parties to assess or determine what PHMSA's reaction was to the Petitioners' comments and cost data and whether that information was even considered.

PHMSA's failure to address, comment on, or engage with any of Petitioners' comments and data on cost violates the APA and Pipeline Safety Act. Agencies are required to "consider and respond to significant comments received during the period for public comment," including by examining the relevant data and articulating an explanation in response to comments that, if adopted, would require a change to the final rule.[103] In order to meet these obligations, PHMSA must reconsider the Final Rule in light of the evidence put forth by Petitioners on the costs of the Final Rule during the rulemaking proceeding.

2. PHMSA Failed to Conduct a Compliant and Rational Risk Assessment in Considering the Costs and Benefits of the Final Rule

The Final Rule is not supported by "a reasoned determination that the benefits, including safety and environmental benefits, of the intended standard justify its costs."[104] As such, PHMSA must reconsider the Final Rule because compliance with the Final Rule is not practicable, is unreasonable, and not in the public interest given that the benefits are not justified by the costs. In addition to their prior comments, Petitioners raise the following concerns with the FRIA and whether PHMSA's analysis demonstrates that the benefits of the Final Rule justify its costs.

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[99] *See* Gas Gathering Final Rule, 86 Fed. Reg. at 63,274, 63,277, 63,279-280, 63,281-282.

[100] GPA 2016 Comments, https://www.regulations.gov/document?D=PHMSA-2011-0023-0290; API 2016 Comments, https://www.regulations.gov/document?D=PHMSA-2011-0023-0381; API and GPA, Joint Position Paper, https://www.regulations.gov/document?D=PHMSA-2011-0023-0452; API and GPA, Joint Clarification Letter, https://www.regulations.gov/document?D=PHMSA-2011-0023-0454; API and GPA, Supplemental Comment Letter PHMSA GPAC Presentation, https://www.regulations.gov/document?D=PHMSA-2011-0023-0460; GPA Supplemental Position Paper on "Pipeline Safety: Safety of Gas Gathering Pipelines," RIN 2137-AF38 (Dec. 4, 2018); Supplemental Comment of GPA and API on "Pipeline Safety: Safety of Gas Gathering Pipelines," RIN 2137-AF38, June 2019 Gas Pipeline Advisory Committee Meeting (Sept. 30, 2019).

[101] API 2016 ICF Study at 2

[102] Gas Gathering Final Rule, 86 Fed. Reg. at 63,274, 63,279, 63,281, 62,286, 63,291.

[103] *Perez*, 575 U.S. at 96; *Altera Corp. & Subsidiaries*, 926 F.3d at 1080-81; *La. Fed. Land Bank Ass'n, FCLA*, 336 F.3d at 1080; *Portland Cement Ass'n*, 486 F.2d at 393-94.

[104] *See* 49 U.S.C. § 60102(b)(5).

a) Failure to Consider Alternatives

The Pipeline Safety Act requires PHMSA to explain the reasons for selecting the final regulations in lieu of other alternatives. Executive Order 12866 also requires agencies to consider alternatives and select the regulatory approach that maximizes net benefits.

When compared to the alternatives, PHMSA said that the safety and environmental benefits are categorically the same, but the magnitude of the benefits vary based on the mileage subject to safety requirements under each alternative.[105] However, PHMSA did find that while "Alternative 2 covers the fewest miles of pipeline, . . . ***it would offer the greatest safety benefits per mile*** as it would impose the most stringent safety requirements."[106] Alternative 2 would have cost industry $6 million in annualized compliance costs, while offering the most safety benefits according to PHMSA. Alternative 2 would have applied "all proposed Type C requirements to gathering lines greater than 12.75" up to and including 16" with a structure within the PIR, and to all gathering lines greater than 16 inches."[107]

Yet, PHMSA chose a different alternative that resulted in over double the costs to industry without explaining how such a large increase in costs justified the benefits of that alternative. Because PHMSA failed to place a valuation on the benefits in the FRIA (unlike its $11.3 million annualized estimate in the PRIA), it is difficult to tell how the benefits of the selected alternative outweigh the benefits of Alternative 2 and are justified by the near doubling of the costs. PHMSA did not provide a reasoned explanation on how the benefits of the Final Rule, and its associated costs, outweigh the benefits associated with any other alternative, specifically Alternative 2.[108]

While not required to consider every conceivable alternative, the APA requires that agencies address reasonable alternatives that are within the bounds of the rulemaking.[109] In this case, PHMSA failed to adequately explain why it chose the framework in the Final Rule as compared to Alternative 2. The Agency must reconsider whether its selected alternative is consistent with the requirements in the Pipeline Safety Act and Executive Order 12866.

b) Use of 2006 Data

PHMSA relied on data from 2006 to extrapolate the costs and benefits of the Final Rule. PHMSA found that cost information submitted by IPAA in 2006 provided "the best available information for many of the cost estimates for this rule."[110] API submitted cost data from 2015, yet PHMSA failed to even recognize that industry had placed more recent cost information before it during the rulemaking proceeding. API's independent economic analysis disputed certain cost calculations conducted by PHMSA and provided significant cost data gathered from operators for PHMSA's consideration. API's independent analysis also called into question PHMSA's monetization of the costs and benefits of the Final Rule and demonstrated that the costs would far

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105 FRIA at 33.
106 *Id.* (emphasis added).
107 *Id.* at 10.
108 *Id.*
109 *See State Farm*, 463 U.S. at 50-51; *Chamber of Commerce of the U.S. v. SEC*, 412 F.3d 133, 144 (D.C. 2005).
110 FRIA at 16.

exceed the benefits of the Final Rule.[111] Yet, PHMSA failed to mention the cost information and data submitted by API and any other commenter.[112] PHMSA provides no explanation or rational basis for using data 15 years old to justify the cost estimates underlying the Final Rule, while simultaneously ignoring more recent data submitted during the rulemaking proceeding. PHMSA must reconsider whether the data provide by API changes the FRIA, or at least provide an explanation as to why it has ignored that data.

c) Other Topics

There are several assumptions that underly PHMSA's FRIA that should be reconsidered. First, PHMSA assumed that only 10% of Type C gathering lines (those with diameters between 8 and 16 inches) "will have a structure intended for human occupancy [or other impacted site] within the PIR" or class location unit making the line subject to additional safety requirements.[113] Using this assumption, PHMSA found that the PIR criterion reduces the miles of regulated pipe and costs of the rule, while increasing benefits by focusing on those gathering lines that are most likely to have more severe consequences in the event of an incident.[114] However, it is unclear what data or basis PHMSA has for assuming that only 10% of Type C gathering lines (those with diameters between 8 and 16 inches) will have a structure intended for human occupancy or other impacted site within the PIR or class location unit. This assumption has significant impacts on the cost implications because if more mileage meets the Type C criteria, the costs of the Final Rule will be significantly higher. Nor does the Agency explain if its assumption accounts for the fact that operators will need to apply certain practices to segments outside of the potential impact circle to achieve compliance if a building intended for human occupancy or other impacted site exists within the PIR. The corrosion control requirements in subpart I, for example, will certainly require remedial measures that extend beyond the potential impact circle, increasing the compliance costs.

The Agency stated the Final Rule *reduced* the costs of compliance as compared to the proposed rule. PHMSA's basis for that statement was the fact that the Final Rule imposed the most significant requirements only on the large-diameter pipelines and certain small-diameter pipelines.[115] However, PHMSA's estimate of the costs of compliance listed in the Final Rule actually *exceeded* the costs included in the NPRM. The estimate in the NPRM was that the costs of compliance would be $12.6 million annually, compared with $13.7 million annually in the Final Rule.

PHMSA also assumed that of the Type C mileage that will become regulated, 97% of those pipelines are operated by operators of currently regulated lines.[116] Therefore, PHMSA assumes that the costs for those operators will be less. However, PHMSA does not explain how it reached this conclusion, nor does the Agency offer any views on the percentage of regulated gathering operators that operate Type R lines. Most of PHMSA's cost estimates consider that operators will already have the required programs, and as such, the costs are limited to including the newly

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[111] API 2016 ICF Study.
[112] *See* FRIA.
[113] *Id.* at 15.
[114] *Id.*
[115] Gas Gathering Final Rule at 63,286.
[116] FRIA at 15.

regulated Type C mileage into existing regulatory programs. Yet, it does not appear that PHMSA considered that even if operators have PHMSA-regulated compliance programs, those same operators may not have the required information needed to comply with the Final Rule on thousands of miles of previously unregulated pipelines. The costs of gathering that information far exceed the costs of simply extending regulatory programs to new pipeline mileage. Operators will need to hire new personnel and obtain additional equipment to achieve compliance.

Lastly, PHMSA's assumes the benefits of the Final Rule in terms of reduced incidents based on Class 1 and 2 transmission line incident data.[117] PHMSA does not attempt to estimate how many incidents will be avoided based on the transmission line data, which is odd given that it assumes the number of fatalities, injuries, excavations, and property damage associated with Class 1 and 2 transmission line incidents caused by corrosion or excavation damage.[118] PHMSA clearly based those figures off the number of transmission line incidents, but does not include that number in the FRIA or address how it used that data to estimate the number of incidents or avoided incidents as a result of the Final Rule. Petitioners previously raised this issue in their comments.

B. PHMSA Must Revise the Final Rule to Reflect that the Benefits of the Requirements are Justified by the Costs.

Given Petitioners' prior comments during the rulemaking proceeding, ICF's economic analysis, and the comments above regarding the Final Rule and FRIA, Petitioners respectfully request the following revisions to the Final Rule that may support a reasoned determination that the cost benefit analysis is supported, and the new requirements are justified. GPA and API have attached proposed redlines to the Final Rule to this Petition for PHMSA's consideration.

1. PHMSA should align the reporting compliance deadlines with the requirement to classify onshore gas gathering lines in § 192.8(b) and provide an exception to the safety related condition reporting requirements for certain Type C lines.

The compliance deadlines for the new reporting requirements in Part 191 (49 C.F.R. §§ 191.15 and 191.17) for existing Type C gathering lines should be aligned with the compliance deadline for determining the classification of onshore gas gathering lines in 49 C.F.R. § 192.8(b). Otherwise, operators will have the obligation to comply with reporting requirements for existing onshore gas gathering lines that arise before the obligation to determine if those lines qualify as Type C lines.

Petitioners recognize PHMSA's interest in gathering annual reports by March 15, 2023, and that the extension of the classification deadlines could affect operators' ability to supply the required data by that date. Petitioners propose that PHMSA allow operators to treat all existing Class 1 gathering lines as Type R and use the Type R Annual Report Form until May 16, 2023, for pipelines with an outside diameter equal to or greater than 12.75 inches, and May 16, 2026, for pipelines with an outside diameter of less than 12.75 inches. PHMSA should also permit operators to submit annual reports with unknown fields if such data has not been collected as of December

[117] *Id.* at 30-32.
[118] *Id.* at 31.

31, 2023, and December 31, 2026, respectively. This approach will allow PHMSA to gather initial information on previously unregulated Class 1 gas gathering lines while recognizing that operators need time to gather information to determine whether the Type C criteria are met.

Petitioners request that PHMSA also clarify that the safety related condition reporting requirements in 49 C.F.R § 191.23 do not apply to Type C gathering lines that are not required to establish MAOP under 49 C.F.R. § 192.9. The Agency stated in the Preamble to the Final Rule that the Agency "is not requiring operators who are not required to establish an MAOP under part 192 to comply with requirements to report MAOP exceedances and other safety-related condition reports."[119] However, PHMSA did not codify this exception. Accordingly, because operators of many Type C lines are not required to establish MAOP, a foundation of most of the safety related conditions, these lines must be exempt from 49 C.F.R § 191.23.

2. PHMSA should clarify that the 10-mile incidental gathering limitation only applies to new pipelines.

The Final Rule adds a new limitation to 49 C.F.R. § 192.8(a) that requires operators to treat an incidental gathering line as a transmission line if the pipeline extends 10 or more miles in length. That limitation, according to the language in section § 192.8(a)(5), applies to new pipelines installed after May 16, 2022, as well as to existing pipelines that are replaced, relocated, or otherwise changed.

The Petitioners do not object to applying the 10-mile limitation to new pipelines. Operators of new incidental gathering lines can be reasonably expected to comply with the regulations for gas transmission lines if the pipeline meets or exceeds the 10-mile threshold. However, the same cannot be said for operators of existing incidental gathering lines. Operators that repair, replace, or otherwise change existing, but previously unregulated, incidental gathering lines that are 10 or more miles long will have to comply with the conversion-to-service requirements in 49 C.F.R. § 192.14 if the entire pipeline becomes a transmission line. To satisfy those requirements, the operator will have to develop and implement a conversion-to-service plan, the provisions of which must include reviewing the design, construction, operation, and maintenance history of the pipeline and, if sufficient historical records are not available, performing appropriate tests, visually inspecting the pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments, correcting defects and conditions, and conducting a pressure test in accordance with subpart K to substantiate MAOP. PHMSA did not consider the costs associated with implementing these requirements in the FRIA or discuss any of the resulting impacts on operators of existing incidental gathering lines in the Final Rule.

Nor did the Agency consider the costs, benefits, or other impacts of applying the 10-mile limitation to existing Type A, Type B, or Type C incidental gathering lines that become transmission lines due to a repair, replacement, or other change that occurs in the future. Operators of these lines will experience additional compliance burdens, particularly for Type B and Type C lines that become subject to all of the operations, maintenance, integrity management, and other requirements for gas transmission lines in 49 C.F.R. Part 192. To avoid these unintended

[119] Gas Gathering Final Rule, 86 Fed. Reg. at 63,275.

consequences, the 10-mile limitation in section 192.8(a)(5) must only apply to new pipelines that are entirely constructed after May 16, 2022.

3. PHMSA should extend the deadline for classifying existing Type C gathering lines to May 16, 2023, for pipelines greater than 12.75 inches in diameter and May 16, 2026, for pipelines 12.75 inches or less in diameter.

The 6-month compliance deadline for determining if an existing onshore gas gathering line qualifies as a Type C line under 49 C.F.R. § 192.8(b) is unreasonable. In the final rule that created the two existing categories of regulated gas gathering lines, Type A and Type B ("2006 final rule"), PHMSA did not impose a deadline for determining the classification of existing pipelines.[120] In response to comments, PHMSA recognized that the proposed 6-month compliance deadline for certain safety requirements did not afford operators enough time to classify their gathering lines.[121] Accordingly, PHMSA extended all compliance deadlines by one year providing operators additional time to classify their lines.[122]

PHMSA should take the same approach here. The Final Rule requires operators to gather a substantial amount of new information on previously unregulated gathering lines to not only identify whether the line is Type C, but also to comply with the new safety requirements. Operators must become familiar with the regulations, train (or hire) the necessary personnel, and begin to assess at each configuration one-by-one on thousands of miles of pipe and related facilities. Petitioners' members are concerned with the ability to procure materials, and the necessary labor, to implement the Final Rule in accordance with the existing deadlines, particularly in light of the current global supply chain issues resulting from the COVID-19 pandemic. It also appears from the preamble of the Final Rule that the Agency actually intended to provide more than six months to classify Type C lines.[123] PHMSA should extend the deadline to classify and determine the beginning and endpoints of existing but previously unregulated gathering lines to May 16, 2023, for pipelines with an outside diameter equal to or greater than 12.75 inches, and to May 16, 2026, for pipelines with an outside diameter of less than 12.75 inches.

PHMSA asserts in the Final Rule that "most Type C gathering lines are relatively modern shale gas systems and [the] basic records should be readily accessible" to determine whether the line qualifies as Type C.[124] This assumption does not apply to the thousands of miles of Class 1 gathering lines that are located in other parts of the country. These lines, which are typically less than 12.75 inches in outside diameter, will require more time and resources to gather the information necessary to make the Type C classification. Requiring operators to treat these lines as Type R gathering lines until Type C determinations can be reasonably made satisfies the Agency's information collection needs. This framework reduces the costs of the Final Rule by providing operators additional time to conduct the necessary activities to gather information on over 400,000 miles of newly regulated gathering lines. The information gathering benefits of the

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[120] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 Fed. Reg. 13,289 (Mar. 15, 2006) (hereinafter "2006 Final Rule").
[121] *Id.* at 13,298.
[122] *Id.*
[123] Gas Gathering Final Rule, 86 Fed. Reg. at 63,276.
[124] *Id.* at 63,281.

Final Rule remain nearly the same as operators will report these lines as Type R until the Type C classification is finalized.

Allowing individual operators to ask the Agency to approve an alternative compliance deadline does not make the 6-month compliance deadline in 49 C.F.R. § 192.8 reasonable. In the 2006 final rule, PHMSA included a similar provision, allowing operators of existing Type A and Type B lines to ask the Administrator to find that later compliance deadline was justified in a particular case, but still refused to include a 6-month compliance deadline. Instead, the Agency established compliance deadlines of between 18 to 36 months. Nor does the availability of individualized relief provide the certainty necessary to address the adverse industrywide impacts that will result from the 6-month deadline. PHMSA retains the authority to deny an operator's request, and the record provides no information on the potential impact that could result from the Agency's decision to approve piecemeal requests.

4. PHMSA should extend the compliance deadlines for existing Type C gathering lines to May 16, 2025, for pipelines greater than 12.75 inches in diameter and May 16, 2028, for pipelines 12.75 inches or less in diameter.

The compliance deadlines in 49 C.F.R. § 192.9(g) for existing Type C gathering lines should be extended and staggered based on outside diameter to accommodate the significant impact that the new reporting requirements and safety standards will have on operators and other affected parties throughout the midstream industry. In the 2006 final rule, which affected considerably less pipeline mileage, PHMSA afforded existing gathering line operators between 18 months and 36 months to comply with the new safety standards for previously unregulated pipelines.[125] PHMSA explained that it "proposed the shorter timelines for provisions that require less time to implement, such as damage prevention. It proposed longer time frames for provisions that may require more time to procure and install materials."[126] Accordingly, it is appropriate to take the same approach to Type C lines. The Type C requirements apply to far more pipeline mileage, and the compliance deadlines must be extended to account for that fact.

For Type C lines with outside diameters equal to or greater than 12.75 inches, the compliance deadline should be extended to three years after the effective date of the Final rule, or until May 16, 2025. This deadline will allow operators adequate time to implement new compliance programs that involve capital and expanded operating costs, such as for corrosion control, leakage surveys, and line markers, and hiring additional personnel. Because PHMSA assumed that operators already had such programs in place for a majority of these pipelines, PHMSA significantly underestimated the impact of these requirements on operators of existing lines, both as to the overall cost of new equipment and as to the availability of resources to perform work within a short compliance period. The supply chain, labor issues, and other market distortions resulting from the ongoing COVID-19 pandemic makes these concerns even more acute.

For Type C lines with outside diameters less than 12.75 inches, the compliance deadline should be extended to six years after the effective date of the Final Rule, or until May 16, 2028.

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[125] 2006 Final Rule, 71 Fed. Reg. at 13,303.
[126] *Id.* at 13,298.

The purpose of the extension is to allow operators adequate time to identify Type C lines, which will require the collection of significant data (such as SMYS and steel type) that is not currently available in many cases for these smaller diameter rural lines. The extension also allows operators to first implement compliance requirements for larger Type C lines, such as cathodic protection and leakage surveys, as these lines present a higher risk. The compliance deadlines in Section 192.13 must also be revised accordingly.

As with the 6-month compliance in 49 C.F.R. § 192.8(b), the fact that individual operators can ask the Agency to approve an alternative compliance deadline does not make the 12-month compliance deadline in 49 C.F.R. § 192.9(g) reasonable. In the 2006 final rule, PHMSA included a similar provision, allowing operators of existing Type A and Type B lines to ask the Administrator to find that later compliance deadline was justified in a particular case, but still afforded operators between 18 to 36 months to achieve compliance. Nor does the availability of individualized relief address the industrywide impacts that will result from the 6-month deadline. PHMSA retains the authority to deny an operator's request, and the record provides no information on the potential impact of the Agency's decision to approve piecemeal requests.

The record demonstrates that the deadlines in 49 C.F.R. § 192.9(g) are unreasonable, inconsistent with previous rulemakings, and that the ability of operators to request individualized relief is inadequate given the industrywide impacts of the new requirements for existing Type C lines. The costs to gather the information needed to request alternative compliance deadlines are not considered in the FRIA and further add to the costs of compliance with the Final Rule. PHMSA failed to consider the significant cost to operators to comply with these short deadlines while also failing to consider whether the costs would be reduced if longer compliance deadlines were provided. PHMSA failed to explain how the costs associated with these compliance deadlines are justified by the benefits of the Final Rule.

5. PHMSA should extend the compliance deadlines for future Type C gathering lines to 24 months.

The compliance deadline in 49 C.F.R. § 192.9(g)(5) should be extended to 24 months to align with the class change deadline in § 192.611. Operators use the 24-month deadline in addressing pipelines that become subject to additional regulations due to a change in class location. As such, this change will provide more consistency in operators' programs.

6. PHMSA should change the requirements and exceptions for Type C lines.

a) Default Yield Strength

The criteria for determining whether a pipeline is a Type C regulated onshore gas gathering line under 49 C.F.R. § 192.8(e) should be clarified to acknowledge that operators can use a default yield strength of 24,000 psi (165 Mpa) in calculating the SMYS of steel pipe as provided in 49 C.F.R. § 192.107(b)(2). Using the default yield strength value in determining the design pressure of steel pipe is appropriate in cases where an operator has information about the other relevant factors, including the nominal outside diameter and wall thickness, but does not have access to the information necessary to calculate SMYS.

b) Type C gathering lines with outside diameters greater than or equal to 8.625 inches to 12.75 inches

The safety standards in 49 C.F.R. § 192.9(e)-(f) for Type C regulated onshore gas gathering lines should be modified to meet the necessary cost-benefit justification, particularly for pipelines between 8.625 and 12.75 inches in outside diameter. The record demonstrates that these small diameter pipelines do not present sufficient risk to warrant application of the requirements in the Final Rule, and that the Agency completely ignored substantial cost information in reaching a contrary conclusion. The only appropriate course of action in these circumstances is to limit the applicability of the Type C requirements for smaller diameter pipelines. Petitioners' proposal is consistent with the industry standard, API RP 1182 *Safety Provisions for Large Diameter Rural Gas Gathering Lines*, that PHMSA referenced in the preamble to the Final Rule. API RP 1182 contains recommended safety measures for Class 1 gathering lines that are greater than 12.75 inches in outside diameter.

Given the costs of compliance and reduced safety and environmental risks associated with Class 1 gathering lines between 8.625 and 12.75 inches in outside diameter, it is unreasonable to apply the full set of safety requirements applicable to larger Class 1 gathering lines to these smaller diameter gathering lines. These gathering lines are consistent with the design and operating parameters of typical gathering lines that both Congress and PHMSA had exempted from the federal Pipeline Safety Regulations for decades. PHMSA failed to explain or justify why the risks associated with these lines justify the significant costs placed on operators in applying the expanded set of safety requirements to these low-risk gathering lines. PHMSA even recognized in the FRIA that applying safety regulations to gathering lines with diameters greater than 12.75 would cost less and yield more safety benefits. PHMSA should revise the Final Rule to apply a smaller subset of requirements to gathering lines with outside diameters greater than or equal to 8.625 inches but less than 12.75 inches.

Petitioners propose that only the design, construction, and initial inspection and testing requirements, damage prevention, and emergency response requirements apply to Type C gathering lines greater than or equal to 8.625 inches but less than 12.75 inches. This revision would remove the requirements to install corrosion control, line markers, conduct leakage surveys, and establish a public awareness program for the smaller-diameter Type C lines that have one building intended for human occupancy or other impacted site within the PIR or class location unit.

c) Other Exceptions

The Final Rule exempts Type C gathering lines less than 40 feet in length that are replaced, relocated, or otherwise changed from the design, installation, construction, and initial inspection and testing requirements. The exception to the applicability of the design, installation, construction, initial inspection, and initial testing requirements in 49 C.F.R. § 192.9(f)(2) for Type C pipelines in existence on the effective date of the Final Rule should be increased from 40 feet to at least 500 feet. This threshold is more appropriate because pipe replacements often involve more than 40 feet of pipe. For example, in order to lower 40 feet of a 12-inch gathering line, an operator determined that it would be required to replace 230 feet of pipe in order to slope the line.

d) Leakage Surveys

PHMSA should remove the requirement to use leak detection equipment in conducting leakage surveys for Type C gathering lines. This requirement is stricter than the comparable requirement for transmission lines. Specifically, for unodorized transmission lines, operators are required to use leak detection equipment only for those transmission lines in Class 3 and 4 locations.[127] PHMSA erred in concluding in the Final Rule that "[l]eak detection equipment is already required for leakage surveys on gas transmission lines that are not odorized."[128] Such equipment is not required for unodorized gas transmission lines in Class 1 and 2 locations. Although leak detection equipment is required for Type B gas gathering lines, such lines operate at lower pressures making leaks harder to detect. The costs of requiring operators to use leak detection equipment versus not requiring such equipment was not addressed by PHMSA in the Final Rule or FRIA. Thus, such requirement is not supported by the agency's cost benefit analysis. Removing the leak detection equipment requirement will reduce the compliance costs to operators of Type C gathering lines while having little to no negative impacts on the benefits of requiring leakage surveys. Unlike Type B gathering lines, leaks on Type C lines will be easier to detect without the use of leak detection equipment.

7. PHMSA should clarify the Type C requirements in other respects.

PHMSA should reorganize the new requirements for Type C lines to provide greater clarity. The Final Rule adds provisions that only apply to Type C lines into three different paragraphs in § 192.9, paragraph (e), which contains the substantive safety requirements, paragraph (f), which contains certain exceptions, and paragraph (h), which contains the requirements for composite materials. Having these requirements consolidated into a single paragraph, § 192.9(e), avoids unnecessary confusion about the applicability of these provisions and is consistent with the requirements for Type A and Type B lines.

PHMSA should remove the definition of "building intended for human occupancy" in the Final Rule. That definition conflicts with existing guidance from the Agency on identifying buildings intended for human occupancy under the existing class location regulations. Using two different definitions and guidelines for identifying buildings intended for human occupancy could become difficult and confusing in practice. For clarity, PHMSA should remove the definition and continue to allow operators identify buildings intended for human occupancy in the normal course using the Agency's current guidance.

Finally, PHMSA should consider incorporating the concepts from the cluster rule in 49 C.F.R. § 192.5 into Method 2 of the Final Rule. Specifically, when a building intended for human occupancy or other impacted site requires application of additional safety requirements under 49 C.F.R. § 192.9, the application of those additional safety requirements ends 220 yards (200 meters) from the nearest building intended for human or other impacted site. Incorporating this concept into Method 2 is consistent with the class location rules and makes the new Type C requirements more cost beneficial.

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[127] 49 C.F.R. § 192.706.

[128] Gas Gathering Final Rule, 86 Fed. Reg. at 63,285.

V. Conclusion

GPA and API respectfully request that the PHMSA grant reconsideration of the Final Rule for the reasons provided in this Petition.

Appendix A
Proposed Revisions to 49 C.F.R. Parts 191 and 192

Blue underlined = new text
~~Red text~~ = deleted text

§ 191.3 Definitions.

* * *

Regulated onshore gathering means a Type A, Type B, or Type C gas gathering pipeline system as determined in § 192.8 of this chapter, subject to the deadlines provided in § 192.8(c) of this chapter for determining the status of gathering lines existing on or before May 16, 2022.

* * *

Reporting-regulated gathering means a Type R gathering line as determined in § 192.8 of this chapter, including gathering lines existing on or before May 16, 2022, which are covered by the provisions in § 192.8(d) of this chapter. A Type R gathering line is subject only to part 191.

* * *

§ 191.15 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident report.

(a) *Pipeline systems*

(1) *Transmission or regulated onshore gathering***.** Each operator of a transmission pipeline system or a regulated onshore gathering pipeline gathering system, subject to the deadlines provided in § 192.8(c) of this chapter for determining the status of gathering lines existing on or before May 16, 2022, must submit DOT Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 of this part.

(2) *Reporting-regulated gathering*. Each operator of a reporting-regulated gathering pipeline system, including gathering lines existing on or before May 16, 2022, which are covered by the provisions in § 192.8(d) of this chapter, must submit DOT Form PHMSA F 7100.2-2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 of this part that occurs after May 16, 2022.

(b) *LNG***.** Each operator of a liquefied natural gas plant or facility must submit DOT Form PHMSA F 7100.3 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5 of this part.

(c) *Underground natural gas storage facility.* Each operator of a UNGSF must submit DOT Form PHMSA F7100.2 as soon as practicable but not more than 30 days after the detection of an incident required to be reported under § 191.5.

(d) *Supplemental report.* Where additional related information is obtained after an operator submits a report under paragraph (a), (b), or (c) of this section, the operator must make a supplemental report as soon as practicable, with a clear reference by date to the original report.

* * *

§ 191.17 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Annual report.

(a) *Pipeline systems*

(1) *Transmission or regulated onshore gathering.* Each operator of a transmission or a regulated onshore gathering pipeline system, subject to the deadlines provided in § 192.8(c) of this chapter for determining the status of gathering lines existing on or before May 16, 2022, must submit an annual report for that system on DOT Form PHMSA 7100.2.1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(2) *Type R gathering.* Beginning with an initial annual report submitted in March 2023 for the 2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system, including gathering lines existing on or before May 16, 2022, which are covered by the provisions in § 192.8(d) of this chapter, must submit an annual report for that system on DOT Form PHMSA F 7100.2-3. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(b) *LNG.* Each operator of a liquefied natural gas facility must submit an annual report for that system on DOT Form PHMSA 7100.3-1 This report must be submitted each year, not later than March 15, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by June 15, 2011.

(c) *Underground natural gas storage facility.* Each operator of a UNGSF must submit an annual report through DOT Form PHMSA 7100.4-1. This report must be submitted each year, no later than March 15, for the preceding calendar year.

* * *

§ 191.23 Reporting safety-related conditions.

(a) …

(b) A report is not required for any safety-related condition that -

(1) Exists on a master meter system, a reporting-regulated gathering pipeline, a Type C gas gathering pipeline that is not subject to the MAOP requirements in § 192.619 as provided in § 192.9(c) of this chapter, or a customer-owned service line;

(2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;

(3) Exists on a pipeline (other than an UNGSF or an LNG facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report. Notwithstanding this exception, a report must be filed for:

(i) Conditions under paragraph (a)(1) of this section, unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline; and

(ii) Any condition under paragraph (a)(10) of this section.

(5) Exists on an UNGSF, where a well or wellhead is isolated, allowing the reservoir or cavern and all other components of the facility to continue to operate normally and without pressure restriction.

* * *

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

(a) An operator must use API RP 80 (incorporated by reference, see § 192.7), to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the onshore gathering line is a regulated onshore gathering line under paragraph (b) of this section.

(1) The beginning of gathering, under section 2.2(a)(1) of API RP 80, may not extend beyond the furthermost downstream point in a production operation as defined in section 2.3 of API RP 80. This furthermost downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is involved in the processes of "production and preparation for transportation or delivery of hydrocarbon gas" within the meaning of "production operation."

(2) The endpoint of gathering, under section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.

(3) If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR § 190.9).

(4) The endpoint of gathering, under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthermost downstream compressor used to increase gathering line pressure for delivery to another pipeline.

(5) For new~~, replaced, relocated, or otherwise changed~~ gas gathering pipelines installed after May 16, 2022, the endpoint of gathering under sections 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 (incorporated by reference, see § 192.7)—also known as "incidental gathering"—may not be used if the new pipeline terminates 10 or more miles downstream from the furthermost downstream endpoint as defined in paragraphs 2.2(a)(1)(A) through (a)(1)(D) of API RP 80 (incorporated by reference, see § 192.7) and this section. If a new "incidental gathering" pipeline is 10 miles or more in length, the entire portion of the new pipeline that is designated as an incidental gathering line under 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 shall be classified as a transmission pipeline for purposes of~~subject to all applicable regulations in~~ this chapter~~for transmission pipelines~~.

(b) ~~Each operator must determine and maintain for the life of the pipeline records documenting the methodology by which it calculated the beginning and end points of each onshore gathering pipeline it operates, as described in the second column of table 1 to paragraph (c)(2) below, by~~

~~(1) November 16, 2022 or before the pipeline is placed into operation, whichever is later, or~~

~~(2) An alternative deadline approved by PHMSA. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with § 192.18 and must include the following information:~~

~~(i) Description of the affected facilities and operating environment,~~

~~(ii)Justification for an alternative compliance deadline,~~

~~(iii) Proposed alternative deadline.~~

~~(c)~~ For purposes of part 191 of this chapter and § 192.9, "regulated onshore gathering pipeline" means:

(1) Each Type A, Type B, or Type C onshore gathering line (or segment of onshore gathering pipeline) with a feature described in the second column of table 1 to paragraph (b~~c~~)(2) below that lies in an area described in the third column; and

(2) As applicable, additional lengths of line described in the fourth column to provide a safety buffer:

Table 1 to paragraph (b~~c~~)(2)

Type	Feature	Area	Additional Safety Buffer
A	- Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS. - If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. - Non-metallic and the MAOP is more than 125 psig (862 kPa)	Class 2, 3, or 4 location (*see* § 192.5)	None.
B	- Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part. - Non-metallic and the MAOP is 125 psig (862 kPa) or less	*Area 1.* Class 3 or 4 location *Area 2.* An area within a Class 2 location the operator determines by using any of the following three methods: (a) A Class 2 location. (b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings; (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings	If the gathering pipeline is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in Area 2(b) or 2(c) qualifies a line as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.
C	Outside diameter greater than or equal to 8.625 inches and any of the following: - Metallic and the MAOP produces a hoop stress of 20 percent or more of	Class 1 location	None

	SMYS. Operators may use a yield strength of 24,000 p.s.i. (165 MPa) in determining SMYS if that value is unknown; − If the stress level is unknown, segment is metallic and the MAOP is more than 125 psig (862 kPa); or − Non-metallic and the MAOP is more than 125 psig (862 kPa).		
R	- All other onshore gathering lines	Class 1 and Class 2 locations	none

(3) A Type R gathering line is subject to reporting requirements under part 191 of this chapter but is not a regulated onshore gathering line under this part.

(c) An operator must determine if an onshore gathering line is a Type A, Type B, or Type C gathering line before the pipeline is placed into service, or by the following deadlines if a gathering line existing on or before May 16, 2022, in a Class 1 location was not previously subject to this part:

(1) May 16, 2023, if the pipeline is greater than 12.75 inches in outside diameter;

(2) May 16, 2026, if the pipeline is 12.75 inches or less in outside diameter; or

(3) An alternative deadline approved by PHMSA. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (c)(1) or (2) of this section. The notification must be made in accordance with § 192.18 and must include the following information:

(i) Description of the affected facilities and operating environment,

(ii) Justification for an alternative compliance deadline,

(iii) Proposed alternative deadline.

(d) Each onshore gathering line existing on or before May 16, 2022, in a Class 1 location that was not previously subject to this part shall be treated as a Type R gathering line until an operator makes the determination required under paragraph (c) of this section.

(e) An operator must maintain records documenting the methodology used in making the determinations required under this section for life of the pipeline.

* * *

§ 192.9 What requirements apply to gathering lines?

(a) . . .

(e) *Type C lines.* Except as provided in paragraphs (e)(5), (e)(6), and (e)(7) of this section, the requirements for Type C gathering lines are as follows.

(1) ~~An operator of a Type C onshore gathering line with an outside diameter greater than or equal to 8.625 inches must comply with the following requirements:~~

~~(i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials,~~ If a line is new, replaced, relocated, or otherwise changed after May 16, 2022, the design, installation, construction, initial inspection, and initial testing ~~of a new, replaced, relocated, or otherwise changed Type C gathering line,~~ must be done in accordance with the requirements in subparts B though G and subpart J of this part applicable to transmission lines~~.~~, except for the requirements in ~~Compliance with~~ §§ 192.67, 192.127, 192.205, 192.227(c), 192.285(e), and 192.506 ~~is not required~~;

~~(ii) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except for § 192.493;~~

(2)~~(iii)~~ Carry out a damage prevention program under § 192.614;

(3)~~(iv)~~ Develop and implement procedures for emergency plans in accordance with § 192.615;

(4) For a line with an outside diameter greater than 12.75 inches,

(i) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except for § 192.493;

~~(v)~~(ii) Develop and implement a written public awareness program in accordance with § 192.616; and

~~(vi)~~(iii) Install and maintain line markers according to the requirements for transmission lines in § 192.707.

~~(vii)~~(iv) Conduct leakage surveys in accordance with the requirements for transmission lines in § 192.706 ~~using leak-detection equipment~~, and promptly repair hazardous leaks in accordance with § 192.703(c); and

~~(2) An operator of a Type C onshore gathering line with an outside diameter greater than 12.75 inches must comply with the requirements in paragraph (e)(1) of this section and the following:~~

~~(i)~~ (v) If the pipeline contains plastic pipe, the operator must comply with all applicable requirements of this part for plastic pipe or components. This does not include pipe and components made of composite materials that incorporate plastic in the design; and

~~(ii)~~(vi) Establish the MAOP of the pipeline under § 192.619(a) or (c) and maintain records used to establish the MAOP for the life of the pipeline.

~~(f)~~(5) ~~Exceptions.(1)~~Compliance with paragraphs ~~(e)(1)(ii), (e)(1)(v), (e)(1)(vi), (e)(1)(vii), and (e)(2)~~ (e)(4)(v) and (e)(4)(vi) of this section is not required for pipeline segments that are greater than 12.75 inches but less than 16 inches ~~or less~~ in outside diameter if one of the following criteria are met:

(i) *Method 1*: The segment is not located within a potential impact circle containing a building intended for human occupancy or other impacted site. The potential impact circle must be calculated as specified in § 192.903, except that a factor of 0.73 must be used instead of 0.69. The MAOP used in this calculation must be determined and documented in accordance with paragraph (e)(2)(ii) of this section.

(ii) *Method 2*: The segment is not located within a class location unit (see § 192.5) containing a building intended for human occupancy or other impacted site. The length of the class location unit may be adjusted to end 220 yards from any building intended for human occupancy or other impacted site.

~~(2) Paragraph (e)(1)(i) of this section is not applicable to pipeline segments 40 feet or shorter in length that are replaced, relocated, or changed on a pipeline existing on or before May 16, 2022.~~

~~(3)~~(iii) For purposes of this section, the term "~~building intended for human occupancy or~~ other impacted site" means any of the following:

~~(i) Any building that may be occupied by humans, including homes, office buildings factories, outside recreation areas, plant facilities, etc.;~~

(i~~i~~) a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive); or

(ii~~i~~) any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1 (see: https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classific atio ns/fcauab.pdf).

(6) Paragraphs (e)(1)-(5) of this section do not apply to a pipeline existing on or before May 16, 2022, if a segment 500 feet or less in length is replaced, relocated, or otherwise changed.

(7) Pipe and components made with composite materials not otherwise authorized for use under this part may be used on a Type C gathering line if the following requirements are met:

(i) Steel and plastic pipe and components must meet the installation, construction, initial inspection, and initial testing requirements in subparts B though G and J of this part applicable to transmission lines.

(ii) The operator notifies PHMSA in accordance with § 192.18 at least 90 days prior to installing new or replacement pipe or components made of composite materials otherwise not authorized for use under this part. The notification must include a detailed description of the pipeline facilities in which pipe or components made of composite materials would be used, including:

(A) The beginning and end points (stationing by footage and mileage with latitude and longitude coordinates) of the pipeline segment containing composite pipeline material and the counties and States in which it is located;

(B) A general description of the right-of-way including high consequence areas, as defined in § 192.905;

(C) Relevant pipeline design and construction information including the year of installation, the specific composite material, diameter, wall thickness, and any manufacturing and construction specifications for the pipeline;

(D) Relevant operating information, including MAOP, leak and failure history, and the most recent pressure test (identification of the actual pipe tested, minimum and maximum test pressure, duration of test, any leaks and any test logs and charts) or assessment results;

(E) An explanation of the circumstances that the operator believes make the use of composite pipeline material appropriate and how the design, construction, operations, and maintenance will mitigate safety and environmental risks;

(F) An explanation of procedures and tests that will be conducted periodically over the life of the composite pipeline material to document that its strength is being maintained;

(G) Operations and maintenance procedures that will be applied to the alternative materials. These include procedures that will be used to evaluate and remediate anomalies and how the operator will determine safe operating pressures for composite pipe when defects are found;

(H) An explanation of how the use of composite pipeline material would be in the public interest; and

(I) A certification signed by a vice president (or equivalent or higher officer) of the operator's company that operation of the applicant's pipeline using composite pipeline material would be consistent with pipeline safety.

(iii) Repairs or replacements using materials authorized under this part do not require notification under this section.

~~(g)~~(f) ***Compliance deadlines.*** An operator of a regulated onshore gathering line must comply with the following deadlines, as applicable.

(1) . . .

(4) If a Type C gathering pipeline existing on or before May 16, 2022, was not previously subject to this part, an operator must comply with the applicable requirements of this section by~~, except for paragraph (h), on or before~~:

(i) ~~May 16, 2023, or~~ May 16, 2025, for a pipeline greater than 12.75 inches in outside diameter;

(ii) May 16, 2028, for a pipeline 12.75 inches or less in outside diameter; or

~~(ii)~~(iii) An alternative deadline approved by PHMSA. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with § 192.18 and must include a description of the affected facilities and operating environment, the proposed alternative deadline for each affected requirement, the justification for each alternative compliance deadline, and actions the operator will take to ensure the safety of affected facilities.

(5) If, after May 16, 2022, a change in class location, an increase in dwelling density, or an increase in MAOP causes a pipeline to become a Type C gathering pipeline, or causes a Type C gathering pipeline to become subject to additional Type C requirements (see § 192.9(f)), the operator has ~~1 year~~ 24 months after the pipeline becomes subject to the additional requirements to comply with this section.

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

(a) No person may operate a segment of pipeline listed in the first column of paragraph (a)(3) of this section that is readied for service after the date in the second column, unless:

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part according to the requirements in § 192.14.

(3) Compliance Deadlines

Pipeline	Date
(i) Offshore gathering line	July 31, 1977
(ii) Regulated onshore gathering pipeline to which this part did not apply until April 14, 2006	March 15, 2007
(iii) Regulated onshore gathering pipeline greater than 12.75 inches in outside diameter to which this part did not apply until May 16, 2022	May 16, ~~2023~~2025
(iv) Regulated onshore gathering pipeline 12.75 inches or less in outside diameter to which this part did not apply until May 16, 2022	May 16, 2028
All other pipelines	March 12, 1971

(b) No person may operate a segment of pipeline listed in the first column of this paragraph that is replaced, relocated, or otherwise changed after the date in the second column of this paragraph, unless the replacement, relocation or change has been made according to the requirements in this part.

Pipeline	Date
(1) Offshore gathering line	July 31, 1977
(2) Regulated onshore gathering line to which this part did not apply until April 14, 2006	March 15, 2007
(3) Regulated onshore gathering pipeline greater than 12.75 inches in outside diameter to which this part did not apply until May 16, 2022	May 16, ~~2023~~2025
(4) Regulated onshore gathering pipeline 12.75 inches or less in outside diameter to which this part did not apply until May 16, 2022	May 16, 2028
All other pipelines	November 12, 1970

(c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

§ 192.18 How to notify PHMSA.

(a) . . .

(c) Unless otherwise specified, if the notification is made pursuant to §§ 192.8~~(b)(2)~~(c)(3), 192.9~~(g)(4)~~(e)(7)(ii), 192.9~~(h)~~(f)(iii), 192.461(g), 192.506(b), § 192.607(e)(4), § 192.607(e)(5), 192.619(c)(2), § 192.624(c)(2)(iii), § 192.624(c)(6), § 192.632(b)(3), § 192.710(c)(7), § 192.712(d)(3)(iv), § 192.712(e)(2)(i)(E), § 192.921(a)(7), 192.927(b), or § 192.937(c)(7) to use a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (i.e., “other technology”) that differs from that prescribed in those sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct its review.

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

(a) . . .

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline Segment	Pressure date	Test date
(i) Onshore gathering line (Type A or Type B under § 192.9(d)) that first became subject to this part (other than § 192.612) after April 13, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
(ii) Onshore regulated gathering pipeline (Type C under § 192.9~~(d)~~(e)) greater than 12.75 inches in outside diameter that first became subject to this part (other than § 192.612) on or after May 16, 2022	May 16, ~~2023~~2025, or date pipeline becomes subject to this part, whichever is later	5 years preceding applicable date in second column
(iii) Onshore regulated gathering pipeline (Type C under § 192.9~~(d)~~(e)) 12.75 inches or less in outside diameter that first became subject to this part (other than § 192.612) on or after May 16, 2022	May 16, 2028, or date pipeline becomes subject to this part, whichever is later	5 years preceding applicable date in second column
~~(iii)~~(iv) Onshore transmission pipeline that was a gathering pipeline not subject to this part before March 15, 2006	March 15, 2006, or date pipeline becomes subject to this part, whichever is later.	5 years preceding date in second column
~~(iv)~~(v) Offshore gathering pipelines	July 1, 1976	July 1, 1971
~~(v)~~(vi) All other pipelines	July 1, 1970	July 1, 1965

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

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance.

(1) An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to

which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with § 192.611.

(2) For any Type C gas gathering pipeline under § 192.9 existing on or before May 16, 2022 that was not previously subject to this part and the operator cannot determine the actual operating pressure of the pipeline for the 5 years preceding ~~May 16, 2023~~ the applicable date in paragraph (a)(3) of this section, the operator may establish MAOP using other criteria based on a combination of operating conditions, other tests, and design with approval from PHMSA. The operator must notify PHMSA in accordance with § 192.18. The notification must include the following information:

(i) The proposed MAOP of the pipeline;

(ii) Description of pipeline segment for which alternate methods are used to establish MAOP, including diameter, wall thickness, pipe grade, seam type, location, endpoints, other pertinent material properties, and age;

(iii) Pipeline operating data, including operating history and maintenance history;

(iv) Description of methods being used to establish MAOP;

(v) Technical justification for use of the methods chosen to establish MAOP; and

(vi) Evidence of review and acceptance of the justification by a qualified technical subject matter expert.