IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

GPA MIDSTREAM ASSOCIATION	)	
Petitioners,	)	
v.	)	Case No. _____
U.S. DEPARTMENT OF TRANSPORTATION and	)	
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION,	)	
Respondents.	)	

PETITION FOR REVIEW

Pursuant to Rule 15(a) of the Federal Rules of Appellate Procedure, Circuit Rule 15, the Pipeline Safety Laws, 49 U.S.C. § 60119, and the Administrative Procedure Act, 5 U.S.C. § 702, the GPA Midstream Association ("GPA Midstream") hereby respectfully petitions this Court for review of the following final rule issued by the U.S. Department of Transportation and Pipeline and Hazardous Materials Safety Administration ("PHMSA"): Pipeline Safety: 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). GPA Midstream and the American Petroleum Institute timely filed a joint petition for reconsideration of the final rule on December 15, 2021, and PHMSA issued a response to the petition on April 1, 2022. For the convenience of the Court, a copy of the final rule, joint petition for reconsideration, and response are attached to this Petition as Exhibits 1, 2, and 3.

/s/ Keith J. Coyle
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Dated May 2, 2022

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Respondents.	)	

RULE 26.1 CORPORATE DISCLOSURE STATEMENT

Pursuant to Rule 26.1 of the Federal Rules of Appellate Procedure and D.C. Circuit Rule 26.1, Petitioner GPA Midstream Association ("GPA Midstream") submits the following Corporate Disclosure Statement.

GPA Midstream has served the U.S. energy industry since 1921. GPA Midstream is composed of nearly 60 corporate members that are engaged in the gathering and processing of natural gas into merchantable pipeline gas, commonly referred to as "midstream activities." Such processing includes the removal of impurities from the raw gas stream produced at the wellhead as well as the

extraction for sale of natural gas liquid products ("NGLs") such as ethane, propane, butane, and natural gasoline or in the manufacture, transportation, or further processing of liquid products from natural gas. GPA Midstream membership accounts for more than 90 percent of the NGLs produced in the United States from natural gas processing. GPA Midstream has no parent companies, and no publicly-held company has a 10 percent or greater ownership interest in GPA Midstream.

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CERTIFICATE OF SERVICE

Pursuant to Rules 15(c) and 25(d) of the Federal Rules of Appellate Procedure, I hereby certify that I have this day caused the foregoing "Petition for Review" and "Corporate Disclosure Statement" to be served upon the following parties by Federal Express overnight:

Pete Buttigieg, Secretary
United States Department of Transportation
Office of the Secretary
1200 New Jersey Ave., SE
Washington, DC 20590

Tristan Brown, Deputy Administrator
Pipeline and Hazardous Materials Safety Administration
Office of the Administrator
1200 New Jersey Ave., SE
Washington, DC 20590

Merrick B. Garland
Attorney General of the United States
U.S. Department of Justice
950 Pennsylvania Ave., NW
Washington, DC 20530

Dated at Washington, DC this 2nd day of May 2022.

/s/ Keith J. Coyle
Keith J. Coyle

EXHIBIT 1

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191 and 192

[Docket No. PHMSA–2011–0023; Amdt. Nos. 191–30; 192–129]

RIN 2137–AF38

Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments

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

ACTION: Final rule.

SUMMARY: PHMSA is revising the Federal Pipeline Safety Regulations to improve the safety of onshore gas gathering pipelines. This final rule addresses Congressional mandates, Government Accountability Office recommendations, and public input received as part of the rulemaking process. The amendments in this final rule extend reporting requirements to all gas gathering operators and apply a set of minimum safety requirements to certain gas gathering pipelines with large diameters and high operating pressures. The rule does not affect offshore gas gathering pipelines.

DATES: The effective date of this final rule is May 16, 2022. The Director of the Federal Register approved the incorporation by reference of certain material listed in this rule as of April 14, 2006.

FOR FURTHER INFORMATION CONTACT:

Technical questions: Steve Nanney, Project Manager, by telephone at 713–272–2855.

General information: Sayler Palabrica, Transportation Specialist, by telephone at 202–366–0559.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of the Final Rule

This final rule responds to Government Accountability Office (GAO) recommendations and a Congressional mandate by extending existing design, operational and maintenance, and reporting requirements under the Federal Pipeline Safety Regulations to onshore natural gas gathering pipelines (''gathering lines'') in rural areas. Increasingly, many of these gathering lines have design and operating parameters that are similar to natural gas transmission lines (''transmission lines''), which pose an increased risk to public safety and the environment. PHMSA expects the regulatory amendments in this final rule will reduce the frequency and consequences of failures of onshore gas gathering lines and in turn reduce the likelihood of gas-related releases and incidents. The requirements in the final rule are designed to prevent and detect threats to pipeline integrity, improve public awareness of pipeline safety, and improve emergency response to pipeline incidents. PHMSA expects this final rule, therefore, will (1) improve public safety; (2) reduce threats to the physical environment (including, but not limited to, greenhouse gas emissions released during natural gas gathering line incidents); and (3) promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities.

Gas gathering lines are pipelines used to transport natural gas from a current production facility to a transmission line or distribution main lines (''main lines''). Generally, these pipelines are used to collect unprocessed gas from production facilities for transport to a gas treatment plant or other facility. From there, the natural gas is separated from petroleum liquids, water, and other impurities to prepare the gas for further transportation and sale. In the Federal Pipeline Safety Regulations (49 Code of Federal Regulations (CFR) parts 190 through 199), gas gathering lines are distinct from gas transmission pipelines which are defined in § 192.3 as pipelines that: (1) Transport gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center; (2) operate at a hoop stress of 20 percent or more of specified minimum yield strength (SMYS); [1] or (3) transport gas within a storage field.

Section 192.5 divides gas transmission and gathering lines into class locations based on the number of dwellings near the pipeline. These range from rural Class 1 to densely populated Class 4 locations. Class locations are defined in § 192.5. A Class 1 location is an offshore pipeline or an onshore pipeline that has 10 or fewer buildings intended for human occupancy within a 1-mile-long class-location unit. Unlike transmission lines, which are regulated regardless of location, gathering lines in rural Class 1 locations are exempt from Federal pipeline safety and reporting regulations in parts 191 and 192. However, PHMSA has authority under 49 U.S.C. 60102(a)(2) to issue safety regulations for pipeline transportation and pipeline facilities, including non-rural gathering lines and rural gathering lines designated by the Secretary as ''regulated gathering lines'' under 49 U.S.C. 60101(a)(21) and (b). Section 60117(b)(2) also authorizes DOT to require owners and operators of gathering lines, including rural gathering lines that have not been defined as regulated gathering lines, to submit information pertinent to its ability to make a determination as to whether and to what extent to regulate gathering lines.

Prior to 2005, U.S. gas production had been stagnant since a peak in the early 1970s.[2] The gathering lines that received gas from conventional wells typically had smaller diameters than gas transmission lines and operated at lower pressures. All else equal, a smaller diameter and lower pressure pipeline will release less gas and energy during an incident compared with a larger diameter pipeline with a greater operating pressure, such as a major transmission line. As a result, gathering lines located in Class 1 locations were

[1] SMYS is defined in § 192.3 and refers to the minimum force required to deform permanently the material as specified in the applicable design codes.

[2] *See* U.S. Energy Information Administration (EIA), ''Natural Gas Explained—U.S. natural gas consumption, dry production, and net imports, 1950–2019,'' *https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php* (accessed Nov. 3, 2020).

thought to pose relatively low risk to the public and the environment; therefore, gathering lines in Class 1 locations were exempt from reporting and safety requirements in the Federal Pipeline Safety Regulations. On the other hand, to account for the risks related to their physical, functional, and operational characteristics, transmission pipelines have been subject to PHMSA regulations regardless of their location.

Regardless of their size, regulated gathering lines are required to comply with safety reporting requirements and minimum safety standards in parts 191 and 192. Section 192.8(b) currently provides for two categories of regulated onshore gathering lines. Type A gathering lines are located in Class 2, Class 3, or Class 4 locations (see § 192.5) that operate at relatively higher stress levels. Section 192.9(c) subjects Type A regulated gathering lines to the same requirements as gas transmission pipelines, with a few exceptions, due to the high potential consequences of an incident on a high-stress pipeline in a populated area. Type B gathering lines are lower-stress pipelines in Class 3, Class 4, and certain Class 2 locations. Section 192.9(d) subjects Type B to a less comprehensive set of requirements since such pipelines operate at lower stress levels than transmission pipelines. As stated above, gathering lines in Class 1 locations are excluded from the reporting and safety standards contained in parts 191 and 192. In a 2006 final rule, PHMSA determined that the potential consequences of a release of a smaller-diameter pipeline with a lower maximum allowable operating pressure (''MAOP''), in a sparsely populated area, would be minimal.[3]

Due to new drilling technologies and changing demand factors, domestic gas production has been surging since approximately 2006.[4] Besides larger overall production volumes, new drilling technologies have also greatly increased the volume of gas that can be extracted from a single production site.[5] As a result, the volume of gas transported by gathering lines have also increased significantly. In order to transport this additional volume, some gas gathering lines are now constructed with large-diameter pipe and operating pressures comparable to large, interstate gas transmission pipelines. For example, the National Association of State Pipeline Safety Representatives (NAPSR)[6] Resolution 2010–2 AC–2 notes that members have observed rural gathering lines as large as 30 inches in diameter with a MAOP as high as 1480 psi.[7] The potential safety and environmental consequences of a gas pipeline rupture are proportional to the pipeline's diameter and operating pressure. Large diameter gathering lines are still exempt from the requirements in parts 191 and 192 if they are located in Class 1 locations despite their physical and functional similarities with transmission pipelines and their increased potential for adverse consequences in the event of incident.

Large diameter, high-pressure gathering lines are susceptible to the same types of integrity threats as transmission pipelines, including corrosion, excavation damage, and construction defects. The exemption of these pipelines from the safety requirements of the Federal Pipeline Safety Regulations failed to consider the present risks that now exist. In addition, PHMSA has lacked detailed information on the safety of gas gathering lines in Class 1 locations because such lines have been exempted from requirements to submit incident and annual reports under part 191. These reports are necessary for PHMSA to analyze how recent changes in the gas production and midstream industries affect the functional and operational characteristics of unregulated gathering lines, and the safety consequences of those changes. While more comprehensive information is being collected and analyzed, expanded regulatory measures are needed to protect the human and natural environment from the consequences of incidents on large-diameter, high-pressure gathering lines from preventable causes such as corrosion, excavation damage, and inadequate design and construction practices.

On August 25, 2011, PHMSA issued an advance notice of proposed rulemaking (ANPRM) that, among other things, requested comments with respect to improving the regulation of gas gathering lines.[8] Following the ANPRM's publication, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act, Pub. L. 112–90) was enacted on January 3, 2012. Section 21 of the 2011 Pipeline Safety Act mandated that DOT review existing regulations for gathering lines and report to Congress on the sufficiency of existing Federal and State laws and the need to modify or revoke existing exemptions from Federal regulation for gathering lines.

Subsequently, in 2012, the GAO issued recommendation GAO–12–388 for PHMSA to collect data on Federally unregulated hazardous liquid and gas gathering lines.[9] In August 2014, GAO issued recommendation 14–667 for PHMSA to ''move forward with rulemaking to address gathering pipeline safety that addresses the risks of larger-diameter, higher-pressure gathering pipelines, including subjecting such pipelines to emergency response planning requirements that currently do not apply to gathering pipelines.''[10]

On April 8, 2016, PHMSA issued a notice of proposed rulemaking (NPRM) responding to comments received on the ANPRM and proposing to further regulate gas gathering lines to enhance safety.[11] This final rule addresses only those portions of the NPRM dealing with gas gathering lines. Portions of the NPRM dealing with gas transmission issues have already been implemented in the final rule, ''Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments,'' (''Gas Transmission Final Rule'') published on October 1, 2019.[12] The remaining gas transmission issues will be addressed in the future in a separate rulemaking under the Regulatory Identifier Number (RIN) 2137–AF39, titled ''Pipeline Safety: Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments.''

The NPRM discussed the Congressional mandate and GAO recommendations, as well as the increased risk factors regarding gathering lines discussed above. In addition, the NPRM explained the need to clarify the definitions of gas gathering lines in §§ 192.3 and 192.8, which rely on American Petroleum Institute (API) Recommended Practice (RP) 80,

[3] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 FR 13289, 13291 (Mar. 15, 2006).

[4] EIA, ''U.S. Natural Gas Marketed Production,'' *https://www.eia.gov/dnav/ng/hist/n9050us2a.htm.* (accessed Nov. 9, 2020).

[5] EIA, ''Hydraulically fractured horizontal wells account for most new oil and natural gas wells,'' *https://www.eia.gov/todayinenergy/detail.php?id=34732* (Jan. 30, 2018).

[6] NAPSR is a nonprofit association of State pipeline safety officials.

[7] Available on the NAPSR website at *http://www.napsr.org/resolutions.html.*

[8] Pipeline Safety: Safety of Gas Transmission Pipelines, 76 FR 53086.

[9] GAO, No. 12–388, ''Pipeline Safety: Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety'' (Mar. 22, 2012).

[10] GAO, No. 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'' at 48 (Aug. 2014).

[11] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 FR 20722.

[12] 84 FR 52180.

''Guidelines for the Definition of Onshore Gas Gathering Lines,'' first edition, April 2000. The current definitions are unclear with respect to each of (1) the point at which a non-jurisdictional production operation ends and a potentially regulated gas gathering line begins and (2) the use of the incidental gathering designation, which allows an operator to designate lines downstream from any gathering function defined in API RP 80 as a gathering line rather than as a transmission line.

A summary of the proposed changes and PHMSA's response to the comments on the NPRM are provided below in section III of this final rule.

On December 28, 2020, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (2020 PIPES Act, Pub. L. 116–260) was enacted. Section 112(a) directed PHMSA to issue a final rule in this rulemaking by March 27, 2021.

B. Summary of the Major Provisions of the Final Rule

This final rule addresses reporting and safety requirements for onshore gas gathering lines; offshore gas gathering lines are beyond the scope of this rulemaking.[13] The final rule requires operators of all onshore gas gathering lines to report incidents and file annual reports under part 191. The purpose of this expanded reporting obligation is to gather data about the state of gas gathering infrastructure and monitor the safety performance of gas gathering lines that were previously exempt from Federal reporting requirements. The information in the reports will help determine the need for future regulatory changes to address the risks to the public, property, and the environment posed by all types of pipeline systems engaged in the transportation of gas.

In addition, the final rule provides for a new Type C regulated gathering line[14] in § 192.8. Type C gathering lines are defined as gas gathering lines in Class 1 locations that have outer diameters of 8.625 inches or greater and operate at higher stress levels or pressures. The safety requirements for Type C lines, referred to as Type C requirements in the final rule, are specified in revised § 192.9(e) and vary based on the outer diameter of the pipeline and the potential consequences of a failure. The potential consequences of incidents are greater on larger-diameter, higher-pressure pipelines and pipelines that are located near buildings intended for human occupancy. Type C gathering lines with an outside diameter greater than 16 inches and certain other Type C gathering lines that could directly affect homes and other structures are required to comply with (1) existing requirements for Type B gas gathering lines, and (2) requirements at § 192.615 that operators develop and implement emergency plans. Type C gathering lines with smaller diameters or that could not directly affect homes and other structures have fewer requirements that are limited to damage prevention, emergency plans, and public awareness. These requirements address known causes of pipeline failures including excavation damage, corrosion, and inadequate design and construction standards.

C. Costs and Benefits

Consistent with 49 U.S.C. 60102(b) and Executive Order 12866 (''Regulatory Planning and Review''),[15] PHMSA has prepared an assessment of the benefits (including safety and environmental benefits) and costs of the final rule as well as reasonable alternatives. PHMSA 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. PHMSA estimates the annualized costs of the rule to be approximately $13.7 million per year at a 7-percent discount rate. The Regulatory Impact Analysis (RIA) for this final rule is available in the docket. The table below provides a summary of the estimated costs for the major provisions in this rulemaking and in total (see the RIA for further detail on these estimates).

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.

II. Background

A. Detailed Overview

Introduction

The Pipeline Safety Regulations divide gas transmission and gathering lines into classes from Class 1 (rural areas) to Class 4 (densely populated, high-rise areas) that are based on the number of buildings or dwellings for human occupancy in the area. Class locations are defined in § 192.5. A Class 1 location is an offshore pipeline or an onshore pipeline that has 10 or fewer buildings intended for human occupancy within a 1-mile-long class-location unit. This final rule addresses only onshore gas gathering lines. Gas gathering lines located in Class 2, Class 3, and Class 4 locations have been subject to reporting requirements in part 191 and safety requirements in part 192. Type A lines, which operate at higher pressure, are required to comply with most safety requirements applicable to transmission pipelines at part 192, while lower-pressure Type B lines are required to follow fewer requirements, which are listed in § 192.9(d).

When PHMSA last issued regulations addressing the safety of gas gathering lines in 2006,[16] it exempted gathering lines in Class 1 locations from reporting and safety requirements in parts 191 and 192. At the time, such pipelines were mostly small-diameter, low-pressure pipelines located in sparsely populated, traditional oil-producing regions and were thought to pose relatively low risks to the public. However, by the time that the 2006 final rule was adopted, innovative drilling technologies, new hydrocarbon discoveries, and increasing demand for natural gas were starting to transform the industry. Highly productive ''unconventional'' drilling techniques have proliferated, and modern production sites can be several times more productive than conventional wells. The characteristics of the gathering lines servicing current wells often have more in common with large interstate transmission systems than the diffuse network of small gathering lines that predominated when the current gas

[13] References in this final rule to ''gathering'' therefore refer, unless specified otherwise, to onshore gas gathering pipelines. Similar to Type A onshore gas gathering lines, offshore gas gathering lines are already covered by the requirements in part 192 applicable to transmission lines, with some exceptions listed in § 192.9(b).

[14] This final rule and amended regulatory text use the formulation ''Type C'' to identify the newly-regulated onshore gathering lines described in the NPRM as ''Type A, Area 2.'' However, in discussion of the NPRM and comments thereon, this final rule will use the formulation ''Type A, Area 2'' for the convenience of the reader.

[15] 58 FR 51375 (Oct. 4, 1993).

[16] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 FR 13289 (Mar. 15, 2006).

gathering regulatory framework was being developed prior to 2006. These changes are placing unprecedented demands and increasing safety risks on the Nation's pipeline system.

The final rule requires operators of all onshore gas gathering lines to prepare and submit annual reports with information about their gas gathering lines and to submit incident reports under part 191. The information is necessary to monitor the safety performance of gas gathering systems and inform the appropriate level of regulatory oversight. This final rule also adopts new safety requirements for larger-diameter (*i.e.,* with outer diameters of 8.625 inches or greater), higher-operating pressure gas gathering lines to mitigate risks to public safety and pipeline integrity. The need to implement risk-based protections and build an understanding of the safety of gas gathering systems is critical since ''unconventional'' production operations continue to expand, often into regions inexperienced with oil and gas development—posing new risks to humans and the environment.

Natural Gas Gathering Infrastructure Overview

The U.S. natural gas pipeline network is designed to transport natural gas to and from most locations in the country. Approximately two-thirds of the lower 48 States depend almost entirely on the interstate transmission pipeline system for their supplies of natural gas.[17] In 49 CFR part 192, pipelines are classified into three broad groups, based on their function and characteristics: Gathering, transmission, and distribution systems. Onshore gathering lines, the sole subject of this final rule, typically transport gas from production fields to gas transmission pipelines or centralized processing and storage facilities. From there, gas is typically transported to large industrial users such as gas-fired power stations or local distribution companies via transmission pipelines. Finally, distribution companies deliver gas to homes and businesses, and other end-users. Together, these systems form an interconnected network that transports natural gas from the production field to its end users. PHMSA estimates that there are over 400,000 miles of onshore gas gathering lines throughout the U.S., the vast majority of which are in Class 1 locations.[18]

Regulatory History

The Natural Gas Pipeline Safety Act of 1968 (Pub. L. 90–481) vested the Secretary with statutory authority to issue regulations to ensure the safe transportation of natural gas by pipeline but excluded the regulation of gas gathering lines in rural areas, which were defined in section 2(3) of the 1968 Act as those locations outside the limits of any incorporated or unincorporated city, town, or village, or other designated residential or commercial area. Later, Congress modified the definition of ''transporting gas'' to provide Secretary the authority to designate non-rural areas in order to make pipelines in those non-rural areas subject to PHMSA's jurisdiction (49 U.S.C. 60101(a)(21)(B)).

PHMSA,[19] through delegation by the Secretary,[20] and its State partners enforce requirements for regulated [21] gas gathering systems in the Federal Pipeline Safety Regulations that are authorized under 49 U.S.C. 60101 *et seq.* DOT issued interim minimum Federal safety standard regulations for gas pipeline facilities and the transportation of natural and other gas by pipeline on November 13, 1968,[22] and subsequently codified broad-based gas pipeline regulations in 49 CFR part 192 on August 19, 1970.[23] The 1970 final rule defined a ''gathering line'' as ''a pipeline that transports gas from a current production facility to a transmission line or main,'' and subjected all gathering lines located in non-rural areas (*e.g.,* within the limits of any incorporated or unincorporated city, town, or village, or other designated residential or commercial area) to all requirements applicable to transmission pipelines (§§ 192.1 and 192.9).

This historical approach to defining PHMSA's jurisdiction, however, has left several key gaps which made it difficult to determine where a gathering line started and ended. One was that it failed to define ''current production facility,'' and therefore the point where a non-jurisdictional production facility became a gathering line was not clear.[24] Additionally, there was no clear definition of where a gathering line ended, and a transmission pipeline or distribution main line began. The DOT has attempted to clarify these gaps several times. In 1974, DOT proposed to revise the definition of a gas ''gathering line'' to address this uncertainty as to the beginning and end points of gas gathering.[25] However, the proposal was later withdrawn.[26]

In 1991, DOT again proposed to revise the definition of a gathering line following a NAPSR survey of its members noting ongoing disagreements about the classification of certain segments of gas pipelines.[27] However, in response to comments on the proposed rule and the issuance of the Pipeline Safety Act of 1992 (Pub. L. 102–508), PHMSA delayed final action on that proposal to consider additional information and the statutory changes. As described earlier, PHMSA was previously restricted from issuing regulations for rural gathering lines. Section 109 of The Pipeline Safety Act of 1992 expanded DOT's authority by authorizing the Secretary to define the term ''regulated gathering line,'' and issue safety regulations for the transportation of gas through those pipelines despite their location in rural areas (49 U.S.C. 60101(b)). The Pipeline Safety Act of 1992 also directed DOT to consider functional and operational characteristics in defining gathering lines (49 U.S.C. 60101(b)(1)(B)(i)). For the definition of the term ''regulated gathering line,'' Congress further directed DOT to consider such factors as location, length of line from the well site, operating pressure, throughput, and gas composition in deciding which gathering lines are functionally gathering yet warrant regulation as regulated gathering lines (49 U.S.C. 60101(b)(2)(A)). This authority also expressly allowed DOT to depart from the concepts used to define gathering for the purposes of determining the scope of the Federal Energy Regulatory

[17] U.S. Department of Energy (DOE), ''Appendix B: Natural Gas—Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure'' p. NG–28 (Apr. 2015).

[18] API estimated there were 240,000 miles of unregulated gathering lines in comments submitted October 23, 2012, available in the docket. In order to project an estimate of gathering lines in service today, PHMSA adjusted this estimate based on average rate of increase in reported mileage of regulated gathering lines from operators' annual reports since 2012. *See* the RIA, available in the docket, for additional information on estimates of gathering miles affected by the rule.

[19] PHMSA's predecessor agencies include the Research and Special Programs Administration (RSPA), the Materials Transportation Bureau (MTB), and the Office of Pipeline Safety (OPS). For simplicity, all are referred to as DOT in this section.

[20] 49 CFR 1.97.

[21] Typically, onshore pipelines involved in the ''transportation of gas,'' *see* 49 CFR 192.1 and 192.3 for detailed applicability.

[22] Interim Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline, 33 FR 16500.

[23] Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, 35 FR 13248.

[24] Transportation of Natural and Other Gas by Pipeline: Proposed Definition of Gathering Line, 39 FR 34569 (Sept. 26, 1974).

[25] Id.

[26] Transportation of Natural and Other Gas by Pipeline: Withdrawal of Proposed Definition of Gathering Line, 43 FR 42773 (Sept. 21, 1978).

[27] Gas Gathering Line Definition: Notice of Proposed Rulemaking, 56 FR 48505 (Sept. 25, 1991).

Commission's (FERC) authority under the Natural Gas Act (15 U.S.C. 717 *et seq.*) in order to define gas gathering lines based on functional, rather than rate-setting, considerations. In other words, whether the DOT classifies a pipeline as a transmission line, gathering line, or regulated gathering line has no impact on the pipeline's status with FERC and vice-versa.

In 1999, PHMSA renewed the effort to define gathering lines. To facilitate this project, PHMSA opened a website for public discussion on the question of how to define gas gathering lines and whether there was a need to subject rural gathering lines to Federal safety oversight.[28] The majority of the comments received focused on the work that was being done by API to classify gathering lines. That effort culminated in the publication of the first edition of API RP 80 in April 2000.

The purpose of API RP 80 is to define gas gathering lines in onshore areas based on the line's function. It distinguishes a gathering function from a ''production operation'' that is not engaged in transportation (see section 2.3 of API RP 80) and defines a number of points that determine the potential endpoint of the gathering function (see section 2.2(a)(1)(A) through (a)(1)(D) of API RP 80), such as the inlet to the furthermost downstream gas processing plant or the furthermost downstream point where gas produced in the same production field or separate production fields is commingled. API RP 80 defines a gathering line as ''a pipeline, or a connected series of pipelines, used to transport gas from the furthermost downstream point in a production operation to the furthermost downstream of one of the defined endpoints of gathering.'' The document also includes supplementary definitions, discussion, and diagrams to provide additional guidance on how operators may apply these definitions to various types of gathering systems. Section 192.8 includes limitations on how aspects of API RP 80 must be applied.

Ever since API RP 80 was first issued, PHMSA has had concerns about ''incidental gathering.'' While section 2.2(a)(1)(A) through (a)(1)(D) describe points where the gathering function can end, paragraph (a)(1)(E) allows an operator to designate pipeline segments that are past the furthermost downstream of the other endpoint of gathering up to the connection to ''another pipeline'' (typically a transmission line) as a gathering line regardless of the actual function or operational characteristics of the pipeline itself. This is the ''incidental gathering'' concept discussed in API RP 80 section 2.2.1.2.6. By definition, these lines extend beyond the end of any gathering functions. When a major gas processing plant or a compressor used to raise the pressure for delivery into a transmission line is the endpoint, the incidental gathering line segment can be indistinguishable from a transmission line in terms of its function, diameter, pressure, and gas composition; yet is treated as a gathering line rather than a transmission line under part 192. Additionally, there are no limits on how far an incidental gathering line may extend under the API RP 80 definition. The API RP 80 concept of ''incidental gathering'' undermines the functional definition of ''gathering'' that API RP 80 was intended to establish. In fact, API RP 80 creates a regulatory gap for pipeline segments that bear the least functional and operational resemblance to gathering lines.

In 2003, DOT held public meetings in Austin, Texas, and Anchorage, Alaska, to determine the best way to define the terms ''gas gathering line'' and ''regulated gathering line'' and what, if any, safety rules would be needed for rural regulated gathering lines.[29] At the meetings, DOT proffered a ''sliding corridor'' concept as a possible basis for defining which gathering lines should be designated as regulated gathering lines. This concept was similar to the ''sliding mile'' used for class location determinations, except that the corridor would be 1,000 feet long rather than one mile, and the width would vary depending on the stress level of the segment of pipe. Wherever the corridor contained five or more dwellings, the gathering line segment would be subject to a subset of Federal Pipeline Safety Regulations, the scope of which would increase as the stress level [30] of the segment increased.

After these two meetings, DOT published a document that stated that the definitions of production and gathering should ensure that Federal regulation of gathering lines does not overlap with State regulations on production, and should promote consistent application by regulators and operators.[31] The document invited comments on an appropriate approach for identifying rural gas gathering lines that warranted regulation. After the 2003 public meetings, DOT met several times with State agency officials, industry representatives, and others to obtain different views on the risks posed by gas gathering lines and the need for Federal regulation over the same.

In 2006, DOT published a final rule that established the current Federal Pipeline Safety Regulations for gas gathering lines in §§ 192.8 and 192.9.[32] The final rule incorporated by reference API RP 80, which defines ''onshore gas gathering pipelines.'' The 2006 final rule also replaced the previous ''non-rural'' criteria for designating regulated gathering lines in § 192.9 with a risk-based approach to regulating gas gathering lines in Class 2, 3, and 4 locations. In the 2006 final rule, PHMSA chose not to extend any reporting or safety requirements to gas gathering lines in Class 1 locations. At the time, PHMSA noted that such pipelines were typically small-diameter, low-pressure lines posing relatively low risks to the public. The Federal requirements for gas gathering lines have remained in place, mostly unchanged, since 2006.

Supply Changes

Between 2005 and 2019, marketed production of natural gas increased from 18.9 trillion cubic feet (Tcf) per year to 36.5 Tcf per year.[33] While gross gas production from conventional wells has fallen by 53 percent from 16.2 Tcf per year to 7.6 Tcf per year between 2005 and 2019,[34] overall production has grown due to increased unconventional shale gas production. EIA began reporting shale gas well withdrawals in 2007. In 2007, unconventional shale gas accounted for about 8 percent of the total natural gas production in the U.S. Since then, shale gas production has increased from 1.9 trillion cubic feet per year to 27.8 trillion cubic feet per year in 2019 [35] and now accounts for

[28] Request for Comments: Gas Gathering Line Definition, 64 FR 12147 (Mar. 11, 1999).

[29] *See* 68 FR 62555 (Nov. 5, 2003) (Austin, TX, meeting) and 68 FR 67129 (Dec. 1, 2003) (Anchorage, AK, meeting). Transcripts for the meeting are available for download at *regulations.gov* under Docket No. PHMSA–RSPA–1998–4868.

[30] Expressed as the circumferential fore on a pipe (hoop stress) produced by the MAOP as a percent of the specified minimum yield strength (SMYS). SMYS is defined in § 192.3 and refers to the minimum force required to deform permanently the material as specified in the applicable design codes.

[31] Gas and Hazardous Liquid Gathering Lines: Clarification of Rulemaking Intentions and Extension of Time for Comments, 69 FR 5305 (Feb. 4, 2004).

[32] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 FR 13289 (Mar. 15, 2006).

[33] EIA, ''U.S. Natural Gas Marketed Production,'' *https://www.eia.gov/dnav/ng/hist/n9050us2a.htm* (accessed Nov. 9, 2020).

[34] EIA, ''U.S. Natural Gas Gross Withdrawals from Gas Wells,'' *https://www.eia.gov/dnav/ng/hist/n9011us2a.htm* (accessed Nov. 9, 2020).

[35] EIA, ''U.S. Natural Gas Gross Withdrawals from Shale Gas,'' *https://www.eia.gov/dnav/ng/hist/ngm_epg0_fgs_nus_mmcfa.htm* (accessed Nov. 9, 2020).

approximately 68 percent of overall gross gas production.

This increase in unconventional gas extraction has shifted production from traditional gas producing regions such as Texas, Louisiana, Oklahoma, and the Gulf of Mexico to other areas, such as Pennsylvania and Ohio. For instance, in 2001, 5,066,015 million cubic feet (MMcf) of natural gas was withdrawn from the Gulf of Mexico, which was approximately 21 percent of the Nation's natural gas gross production. By 2019, withdrawals decreased to 1,033,922 MMcf. During that same period, Pennsylvania's share of production grew from 130,853 MMcf to 6,896,792 MMcf.[36] The Department of Energy projects that more than half of increases in shale gas production through 2050 will occur in the Appalachian Basin (*e.g.,* the Marcellus and Utica Basins), which will continue to fuel growth in natural gas production from the 2020 levels of 33.9 t (Tcf) per year to 43.0 Tcf per year in 2050.[37]

Demand Changes

Increased production of natural gas in the United States has depressed average prices and volatility.[38] In 2004, the growth outlook for natural gas production was weak; the EIA forecasted that dry gas production would increase by only 1.0 percent annually [39] and that production in the lower 48 would be 21.3 Tcf per year by 2025, or up to 25.1 Tcf per year in the rapid technology scenario.[40] At the time, monthly average spot prices at Henry Hub [41] were high, based on historic comparison of prices, fluctuating between $4 per million British thermal units (Btu) and $7 per million Btu. Prices rose above $11 per million Btu for several months in both 2005 and 2008.[42] Since then, after production shifted to onshore unconventional shale resources and price volatility decreased since 2009, natural gas has frequently traded between $2 and $4 per million Btu, and the spot price has not been above $6 per million Btu for any full month.[43]

This fall in natural gas prices and volatility was accompanied by significant demand growth and changes to the geography of gas demand. Low fuel costs, improved gas turbine technology, operational advantages, and greenhouse gas concerns have driven a steady growth in gas-fired electricity generation. According to the Department of Energy, natural gas surpassed coal as the fuel with the highest share of net electricity generation in 2016.[44] Natural gas exports have also increased. In 2019, the U.S. exported 4.7 Tcf of gas, over six times the amount that was exported in 2006.[45] Virtually all the gas produced and consumed in the U.S. is transported by gas gathering and transmission pipelines to distribution pipelines or end-users.

Consequences for Gas Gathering

Modern production techniques, higher production volumes, and the geography of new gas discoveries have had consequences for gas gathering systems that PHMSA did not contemplate in 2006. Individual unconventional wells can be several times more productive than conventional facilities, and multiple wells can be drilled from a single wellpad, resulting in a large increase in the volume of gas that can flow from production and gathering lines serving a single site. In addition, these productivity gains have led to a surge in production overall, which expands the demands placed on the overall gas gathering pipeline network. Modern gas gathering lines often bear a closer resemblance to large interstate transmission lines than the diffuse network of small, low-pressure lines that previously characterized gathering lines. An incident on such pipelines can have serious consequences, even in a Class 1 location.

Although PHMSA has not collected annual report information on the mileage or diameter of gas gathering lines in Class 1 locations, various stakeholders have reported significant growth in large-diameter, high-pressure gas gathering lines operating outside the scope of the Federal Pipeline Safety Regulations. NAPSR noted in the preamble to its Resolution 2010–2 AC–2 that ''it is not uncommon to find rural gas gathering pipelines up to 30 inches in diameter and operating at a MAOP of 1480 psi [pounds per square inch, or approximately 1495 pounds per square inch gauge (psig)]'' in modern gas gathering systems,[46] which resembles the operational characteristics of major interstate transmission pipelines that are subject to part 191 and 192 regardless of where they are located. Similarly, the GAO noted that 24-inch diameter unregulated gathering lines were located and constructed in close proximity to homes in Pennsylvania, and 30 to 36-inch diameter unregulated gas gathering lines were planned for construction in the Eagle Ford shale formation in Texas.[47] In comments to the NPRM, the Pennsylvania Public Utility Commission noted that producers in the State are constructing gas gathering lines as large as 36 inches in diameter with operating pressures up to 1480 psig.

The energy that can be released in a pipeline explosion or fire is proportional to a pipeline's throughput capacity. The potential impact radius formula in § 192.903, which calculates the radius of a circle within which the potential failure of a pipeline could have a significant impact on people or property, increases proportionally with pressure and exponentially with the diameter of the pipeline. An incident on any large-diameter, high-pressure natural gas pipeline can have potentially catastrophic consequences, regardless of whether it is defined as a transmission or gathering line, and even in sparsely populated Class 1 locations. For example, one of the deadliest gas transmission pipeline incidents in U.S. history occurred in a Class 1 location when a 30-inch transmission line operated at 675 psig ruptured near Carlsbad, New Mexico, on August 19, 2000.[48] In that incident, internal

[36] EIA, ''Gulf of Mexico—Offshore Natural Gas Withdrawals,'' *https://www.eia.gov/dnav/ng/hist/na1060_r3fmtf_2a.htm* (accessed Nov. 9, 2020); EIA, ''Pennsylvania Natural Gas Gross Withdrawals,'' *https://www.eia.gov/dnav/ng/hist/n9010pa2a.htm* (accessed Nov. 9, 2020).

[37] EIA, ''Annual Energy Outlook 2021'' (Feb. 3, 2021), *https://www.eia.gov/outlooks/aeo/production/sub-topic-01.php.*

[38] DOE, ''Appendix B: Natural Gas—Quadrennial Energy Review Report: Energy Transmission, Storage, and Distribution Infrastructure,'' at NG–11 (Apr. 2015), *https://www.energy.gov/sites/prod/files/2015/04/f22/QER-ALL%20FINAL_0.pdf.*

[39] EIA, ''Annual Energy Outlook 2004 With Projections to 2025,'' at 133 (Jan. 2004), *https://www.eia.gov/outlooks/archive/aeo04/pdf/0383(2004).pdf.*

[40] *Id.* at 90.

[41] Henry Hub is a Louisiana natural gas distribution hub where conventional Gulf of Mexico natural gas can be directed to gas transmission lines running to different parts of the country. Natural gas bought and sold at the Henry Hub serves as the National benchmark for U.S. natural gas prices. *Id.* at NG–29, NG–30.

[42] EIA, ''Natural Gas Spot and Futures Prices,'' *http://www.eia.gov/dnav/ng/ng_pri_fut_s1_m.htm,* (accessed Nov. 9, 2020).

[43] *Id.*

[44] EIA, ''Electric Power Annual 2019'' Table 3.1.A (Oct. 2020), *https://www.eia.gov/electricity/annual/* (accessed Nov. 9, 2020).

[45] EIA, ''U.S. Natural Gas Exports,'' *https://www.eia.gov/dnav/ng/hist/n9130us2a.htm* (accessed November 9, 2020).

[46] NAPSR, Resolution 2010–2AC–2 (Sept. 30, 2010), *http://nebula.wsimg.com/215b293abe58ff21d6d2ad867ae864a3?AccessKeyId=8C483A6DA79FB79FC7FA&disposition=0&alloworigin=1.*

[47] GAO, No. 14–667 at 24.

[48] National Transportation Safety Board (NTSB), NTSB/PAR–03/01, ''Pipeline Incident Report: Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico'' (Feb. 2003), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR0301.pdf.*

corrosion led to an explosion that killed 12 individuals who had been camping 675 feet from the rupture site. Following this incident, PHMSA added § 192.476 requiring operators to incorporate measures to mitigate internal corrosion threats in the design and construction of new transmission lines—however, that requirement does not affect gathering lines that may have a similar risk profile. In another incident on December 11, 2012, a 20-inch transmission line with a MAOP of 1000 psig ruptured in Sissonville, West Virginia, due to corrosion caused when the protective pipe coating was damaged by rocky backfill during installation. While there were no serious injuries in that incident, three houses and several hundred feet of road surface were destroyed, and Interstate 77 was shut down for 19 hours.[49] The fire melted a portion of the interstate highway, prompting one local official to describe the highway as looking ''like lava, just boiling.'' [50]

Although PHMSA has not historically collected incident reports for gas gathering lines in Class 1 locations, such gathering lines are subject to incidents of similar magnitude and consequence as gas transmission pipelines with comparable physical and operating characteristics. For example, on November 14, 2008, a 20-inch gas gathering line exploded in Grady County, Oklahoma, which injured two people, destroyed three homes, and shut down a nearby highway.[51] On June 8, 2010, a bulldozer struck a 14-inch gas gathering line in Darrouzett, Texas, causing an explosion that killed two workers and injured three others, including one worker who was critically injured and required medical evacuation by helicopter.[52] On June 29, 2010, three men working on a 24-inch gas gathering line in Grady County, Oklahoma, were injured when it exploded; one worker was airlifted to a nearby hospital with burns covering half of his body.[53] On August 1, 2018, a six-inch gas gathering line failed in Midland, Texas, which caused a nearby 12-inch transmission line to also explode, killing one worker and injuring seven others.[54] A few days later, on August 9, 2018, corrosion on a 10-inch gas gathering line resulted in another explosion in Midland, killing a three-year-old girl and badly burning three others. Fatal incidents on smaller lines such as the first Midland, Texas, incident described above and an explosion caused by an improperly abandoned 2-inch production line connected to a gas well in Firestone, Colorado,[55] underscore the need to collect information on the risks posed by smaller diameter lines. Even non-fatal incidents can result in significant damage to infrastructure and property, lead to evacuations, disrupt gas service, or otherwise harm the public, property, or the environment.

These hazards may be further exacerbated by the changing geography of U.S. gas production, which was noted by the GAO in their March 2012 report, ''Collecting Data and Sharing Information on Federally Unregulated Gathering Pipelines Could Help Enhance Safety.'' Incidents involving new gas production fields may overwhelm the capabilities of local first responders in rural areas who may lack experience and the resources to respond adequately to serious incidents associated with intensive gas production and processing operations, including high-pressure pipelines.

Regulatory Gaps

PHMSA estimates that there are over 400,000 miles of unregulated onshore gathering lines. For comparison, operators reported 320,000 miles of gas transmission lines in 2019. As demonstrated above, even though some gathering lines share the same physical, functional, and operational characteristics and potential adverse consequences from an incident as transmission lines, they are exempt from reporting requirements in part 191 and minimum safety standards in part 192.

The final rule closes this gap by requiring all gas gathering facilities to submit incident reports and annual reports under part 191. In addition, the final rule adopts minimum safety standards for larger gas gathering lines that operate at higher pressures to help to ensure that operators address the critical risks that these previously unregulated facilities pose to pipeline integrity and public safety such as corrosion, excavation damage, and inadequate emergency response planning.

B. Advance Notice of Proposed Rulemaking

On August 25, 2011, PHMSA published an ANPRM, soliciting public comments regarding the revision of the Pipeline Safety Regulations applicable to the safety of both gas gathering and gas transmission pipelines.[56] PHMSA requested comments regarding 15 topic areas covering gathering and transmission lines.

The specific issues related to gas gathering included whether regulatory exemptions for filing incident, annual, and safety-related condition reports should be repealed. In addition, PHMSA requested comment on a proposal to repeal the incorporation by reference of API RP 80 into the Pipeline Safety Regulations and replace it with a new definition of gathering lines in part 192 for determining the beginning and end points of gas gathering lines. Adoption of a new definition would address defining endpoints for non-jurisdictional gas production operations and setting limits for the ''incidental gathering'' concept in API RP 80. PHMSA also requested comment on expanding the definition of the term ''regulated onshore gas gathering pipelines'' to include a new category of high-pressure, large diameter gathering lines in Class 1 Locations.

PHMSA received 103 comments to the ANPRM. Based on these comments, PHMSA developed proposals for some of those topics in an NPRM published on April 8, 2016 (NPRM), which is the basis for this final rule.

C. Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011

Section 21 of the 2011 Pipeline Safety Act mandated that DOT review its existing regulations for gas gathering lines and report to Congress on the sufficiency of existing Federal and State laws to ensure the safety of gas

[49] NTSB, NTSB/PAR–14/01, ''Accident Report: Columbia Gas Transmission Corporation Pipeline Rupture Sissonville, West Virginia'' (Feb. 2014), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1401.pdf.*

[50] Brinks, Travis, ''Remembering the Sissonville Pipeline Explosion.'' *WV Metro News.* Dec. 11, 2023, *https://wvmetronews.com/2013/12/11/remembering-the-sissonville-pipeline-explosion/* (accessed June 15, 2021).

[51] Griswold, Jennifer and Sargent, Brian. ''Natural Gas Pipeline Explosion Destroys Homes Near Alex.'' *The Oklahoman,* Nov. 14, 2008, *www.oklahoman.com/article/3321932/natural-gas-pipeline-explosion-destroys-homes-near-alex* (accessed Feb. 12, 2021).

[52] The Associated Press. ''Two Killed in Texas Panhandle Gas Line Explosion.'' *Arkansas Democrat Gazette,* June 8, 2010, *www.arkansasonline.com/news/2010/jun/08/2-killed-texas-panhandle-gas-line-explosion/* (accessed Feb. 12, 2021).

[53] Pittman, Jerry. ''Pipeline Explosion West of Pocasset Injures Three, One Seriously.'' *The Oklahoman,* June 29, 2010, *www.oklahoman.com/article/3472182/pipeline-explosion-west-of-pocasset-injures-three-one-seriously,* (accessed Feb. 12, 2021).

[54] Lee, Mike, and Soraghan, Mike. ''Deadly Pipelines, No Rules.'' *E&E News,* Mar. 4, 2019, *www.eenews.net/special_reports/EEnews_highlights/stories/1060123021,* (accessed Feb. 12, 2021).

[55] NTSB, NTSB/PAB–19/02, ''Pipeline Accident Brief Natural Gas Explosion at Family Residence Firestone, Colorado'' (Oct. 2019), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAB1902.pdf.*

[56] Pipeline Safety: Safety of Gas Transmission Pipelines, 76 FR 53086.

gathering lines; the economic impacts, the technical practicability, and challenges of applying existing Federal regulations to unregulated gathering lines; and the need to modify or revoke existing exemptions from Federal regulation for gathering lines, subject to a risk-based assessment. PHMSA sent the required report to Congress on May 8, 2015.[57] The report identified issues with the difficulty of designated gathering lines in complex systems due to missing, ambiguous, or circular definitions of terms used to determine the start and end points of gathering lines, and used to describe state-level regulation of gathering lines. The report also observed that, with few exceptions, State regulators had not imposed design, construction, operation, and maintenance requirements for gathering lines beyond existing Federal requirements for Type A and Type B regulated gathering lines. The report also notes that most of the States which had established requirements for gathering lines other than Federally regulated Type A and Type B gathering lines had not adopted prescriptive safety standards or performance standards with well-defined authorized acceptance criteria. The report informs this rulemaking.

D. Government Accountability Office (GAO) Recommendations

The GAO issued GAO–12–388 in March 2012, which recommended PHMSA collect data on Federally unregulated hazardous liquid and gas gathering lines comparable to the data collected from operators of regulated gathering lines. The GAO suggested that the purpose of such data collection would be to assess the safety risks posed by unregulated gathering lines. GAO also noted that States and operators could use this information to share effective safety practices and lessons learned. In August 2014, the GAO issued a report, GAO–14–667, which further recommended that PHMSA initiate a rulemaking to address gathering line safety that would focus on the risks presented by larger-diameter, higher-pressure gathering lines, including a requirement that such pipelines meet emergency planning requirements.[58]

E. Notice of Proposed Rulemaking

On April 8, 2016, PHMSA published the NPRM, which proposed new pipeline safety requirements and revisions of existing requirements in 16 major topic areas.

To manage the breadth of the topics raised in the NPRM, PHMSA separated the topics into three final rules. The first of final rule addressed the gas transmission mandates in the 2011 Pipeline Safety Act; a final rule was published in this rulemaking on October 1, 2019.[59] That final rule addresses comments received concerning the scope of the proposed gas transmission requirements for existing Type A and Type B regulated gathering lines. The second final rule is this one, which addresses only the portions of the NPRM affecting the safety of gas gathering lines, particularly reporting requirements for all gas gathering lines and additional requirements for Type C regulated gathering lines. The remaining gas transmission pipeline concerns are being considered in a third final rule (under Regulatory Identification Number 2137–AF39) that is under development.

With respect to the current rulemaking, the NPRM contained proposals to:

(1) Extend part 191 requirements for incident reports, annual reports, and safety-related condition reports to all gas gathering lines;

(2) repeal the incorporation by reference of API RP 80 and revise the regulatory definitions for determining if a pipeline is a gathering line;

(3) expand the scope of regulated gathering lines to include a new category of ''Type A, Area 2'' for gathering lines in Class 1 locations with a diameter of 8 inches or greater and operating at high pressure; and

(4) require newly regulated Type A, Area 2 gathering lines to comply with the existing requirements in § 192.9 for Type B gathering lines, plus an additional requirement for establishing emergency plans per § 192.615.

Pursuant to 49 U.S.C. 60115(c), PHMSA shared the proposed standards on gathering lines with the Gas Pipeline Advisory Committee (GPAC) after initially considering the comments to the NPRM.[60] The GPAC met on June 25–26, 2019, to consider the proposed standards regarding gathering lines. Subsequently, PHMSA posted the meeting slides that were used for the GPAC votes as well as the transcript, which constitute the statutorily required report of the GPAC's recommendations, including minority views.[61]

A summary of the four pertinent NPRM proposals, comments received on these proposals, the GPAC recommendations, and PHMSA's responses to the comments are provided in section III below.

F. Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020

The 2020 PIPES Act was enacted on December 28, 2020. Section 112(a) directed PHMSA to issue a final rule in this rulemaking by the March 27, 2021.

III. Summary of the NPRM Comments, and GPAC Recommendations, and PHMSA Responses

The comment period for the NPRM ended on July 7, 2016, after being extended for one month. PHMSA received over 400 comments from groups representing the regulated pipeline industry; groups representing public interests, including environmental organizations; State utility commissions and regulators; members of Congress; individual pipeline operators; and private citizens. PHMSA received several comments after the July 7, 2016 deadline. Consistent with §§ 5.13(i)(5) and 190.323, PHMSA considered those late-filed comments considering commenters' interest in the rulemaking and the absence of additional expense or delay resulting from their consideration.

Pursuant to 49 U.S.C. 60115(e), the GPAC met on June 25 and 26, 2019 to consider the topics related to the safety of gas gathering lines in the NPRM. The GPAC came to consensus decisions and voted on recommended changes to the NPRM elements that would make those regulatory amendments more technically feasible, reasonable, cost-effective, and practicable. These recommendations are documented in

[57] PHMSA, Report to Congress: Natural Gas and Hazardous Liquid Gathering Lines (May 2015), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/report_to_congress_on_gathering_lines_0.pdf.*

[58] On September 29, 2015, GAO prepared a statement, GAO–15–843T (''Department of Transportation Needs to Complete Regulatory, Data, and Guidance Efforts'') reiterating the need for PHMSA to complete its regulatory efforts based on GAO's previous recommendations.

[59] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, 84 FR 52180.

[60] The Technical Pipeline Safety Standards Committee, or GPAC, is an advisory committee, created pursuant to 49 U.S.C. 60115, that advises PHMSA on proposed safety standards, risk assessments, and safety policies for natural gas pipelines. The GPAC was established under the Federal Advisory Committee Act (Pub. L. 92–463) and section 60115 of the Federal Pipeline Safety Law (49 U.S.C. 60101 *et seq.*). The GPAC consists of 15 members, with membership divided among Federal and State agencies, the regulated industry, and the public. The GPAC considers the ''technical feasibility, reasonableness, cost-effectiveness, and practicability'' of each proposed pipeline safety standard and provide PHMSA with recommended actions pertaining to those proposals.

[61] *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=143.*

the transcript of the meeting and summarized in the vote slides.[62]

A. Reporting Requirements—§§ 191.1, 191.15, 191.17, 191.23, and 191.29

1. Summary of PHMSA's Proposal

Existing § 191.1(b)(4)(ii) exempts all onshore gas gathering lines other than regulated gathering lines (as specified in accordance with § 192.8) from all reporting requirements of part 191.

The NPRM proposed to repeal the exemption in § 191.1(b)(4) for gas gathering lines that are not regulated under § 192.8. However, the NPRM would continue to exempt previously unregulated gathering lines from Operator Identification Number (OPID) validation requirements in § 191.22(b) and National Pipeline Mapping System (NPMS) requirements in § 191.29. Therefore, all gas gathering lines, including previously unregulated gathering lines, would be required to comply with annual and incident reporting requirements in §§ 191.15, 191.17, and 191.25. This proposal was intended to provide new information on the extent, configuration, and safety performance of previously unregulated gas gathering lines.

The proposed rule would have required submission of OPID requests, incident reports, and safety-related condition requests beginning on the effective date of a final rule. Annual reports would have been due on March 15 of the calendar year after the effective date of a final rule.

2. Summary of Public Comments

Several citizen and public safety, and environmental groups, including the Pipeline Safety Trust (PST), the Wisconsin Safe Energy Alliance, NAPSR, the Coalition to Reroute Nexus, Earthworks, and the Environmental Defense Fund (EDF), supported the proposed provisions to remove the exemption for filing reports by operators of unregulated gas gathering lines. NAPSR agreed that extending reporting requirements to ''unregulated'' gathering lines would help determine if current operation and maintenance practices pose a risk to public safety and if additional requirements are required but suggested that PHMSA consider limiting certain requirements that could pose an unnecessary burden, such as detailed leak reporting information in part M of the gas transmission and gas gathering annual report form (DOT Form PHMSA F 7100.2–1). Some public commenters emphasized that available data on unregulated facilities could be inaccurate or outdated, particularly in areas where gas development has grown rapidly. Some of these groups also encouraged PHMSA to require gas gathering operators to submit geospatial pipeline location data for the NPMS, citing the usefulness of NPMS data for determining the need for future regulation.

Trade associations and pipeline industry entities provided a variety of responses to the proposed reporting requirements, ranging from full support, including for NPMS reporting, to total opposition to all proposed reporting requirements. The Independent Petroleum Association of America (IPAA) and other commenters representing oil and gas producers opposed changes to the scope of part 191 and commented that PHMSA has no statutory authority to apply reporting requirements to production lines and gathering lines that are not regulated gathering lines determined pursuant to § 192.8.

Several trade association and pipeline industry commenters including API, GPA Midstream (formerly the Gas Processors Association) and IPAA, expressed concern that the proposed reporting requirements could have significant cost impacts for operators that were not commensurate with the risk posed by the majority of those lines. Industry commenters also commented that it is not feasible to collect the information necessary to complete the proposed annual report by the reporting deadline of March 15 as required by § 191.17 on top of the efforts necessary to identify Type A, Area 2 (or Type C) regulated gas gathering lines within six months of the effective date the rule (see section III.C. below).

Industry commenters were especially concerned about reporting requirements for pipeline attributes that were related to requirements that did not apply to unregulated gas gathering lines. For example, GPA, API, and other industry commenters argued that the reporting of safety-related conditions (§ 191.23), including MAOP exceedances, would require information on MAOP, corrosion monitoring, and SMYS that were not otherwise required for previously unregulated gathering lines. The current forms for submitting gas transmission and gathering incident reports (F 7100.2) and annual reports (F 7100.2–1) also refer to regulations or records not required for unregulated gas gathering operators. These commenters recommended that PHMSA create separate incident and annual report forms for gathering lines that would collect information relevant to gas gathering lines that are not subject to part 192 and eliminate the proposed requirement to report safety-related conditions.

GPA Midstream commented that they supported PHMSA's goal of collecting necessary information on gas gathering lines, but that an abbreviated annual report form was necessary to avoid unnecessary costs. GPA Midstream further commented that unregulated gas gathering lines should be excepted from the OPID validation and change notification requirements in § 191.22(b) and (c).

3. GPAC Recommendations

Following discussion in the June 2019 meetings, the GPAC voted 12–0 that the proposed requirement that operators of newly regulated gas gathering lines file annual and incident reports pursuant to part 191 was technically feasible, reasonable, cost-effective, and practicable, if the following changes are made:

- Add specificity to location (*e.g.,* latitude and longitude coordinates) and cause information to the incident report form;
- Make sure all appropriate current annual report data elements are incorporated in the annual report form for currently unregulated gathering lines, including decade of installation;
- Address the possibility of unknown data;
- Implement a phase-in period of at least 24 months for unregulated gathering annual reports; and
- Consider additional comments from members submitted to the meeting docket (PHMSA–2016–0136), specifically, position papers from API/GPA Midstream and PST submitted in response to the GPAC meeting notice, and comments submitted after the GPAC meeting by each of GPA Midstream and the United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada, AFL–CIO.

The GPAC agreed that the proposed reporting requirements were needed to support future oversight, but recommended changes on the details of implementation. PHMSA explained that it intended to create a new annual report form for gas gathering lines that are not subject to safety requirements in part 192 (reporting regulated gathering lines) separate from the existing DOT Form PHMSA 7100.2–1 required for operators of gas transmission and regulated gas gathering lines. This form would exclude information that is not relevant or applicable to operators of pipeline systems that are not required to comply with part 192.

[62] *See https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=143.*

The GPAC recommended extending the compliance deadline for annual reports to 24 months after publication in the **Federal Register** to grant additional time for operators to identify newly regulated gathering lines and collect the necessary information. However, the GPAC agreed that incident reports should begin to be filed on the effective date of the rule since the data required to submit an incident report should be readily obtainable when an incident occurs.

4. PHMSA Response

PHMSA disagrees with comments that it lacks the statutory authority to require reports from operators of gathering lines other than currently regulated gathering lines as determined under § 192.8. Section 60117(b) of Federal Pipeline Safety Law specifically authorizes the Secretary to ''require owners and operators of gathering lines to provide the Secretary information pertinent to the Secretary's ability to make a determination as to whether and to what extent to regulate gathering lines.'' Congress made no distinction between ''gathering lines'' and ''regulated gathering lines'' for reporting purposes. This information-gathering process is precisely what the NPRM proposed—to gather information on all gathering lines that would enable PHMSA to make informed judgments about the need for, and scope, of potential regulation. Congress intended that the Secretary have the authority to request information from operators of unregulated gathering lines in order to help determine ''what additional gathering lines should be regulated.'' [63] PHMSA seeks to obtain information regarding current risks to people, property, and the environment due to unregulated rural gathering lines to determine whether rural gathering lines are presenting unacceptable risk that would warrant additional regulations. The information contained in annual and incident reports submitted by operators under part 191 would reasonably help achieve this objective.

In addition to the plain meaning of section 60117, Congress has articulated its intent for DOT to obtain information about the risks of rural gathering lines. In 1992, when Congress granted DOT authority to define gathering lines and regulated gathering lines for purposes of safety regulations, it recognized that some rural gathering lines might present unacceptable risks and authorized DOT to regulate lines whose risk warranted regulation. In its report on H.R. 1489, a bill leading to the Pipeline Safety Act of 1992, the House Committee on Energy and Commerce instructed DOT to ''find out whether any gathering lines present a risk to people or the environment, and if so, how large a risk and what measures should be taken to mitigate the risk.'' [64] The Committee reasoned that ''DOT had been attempting to define gathering lines for years. Anecdotal evidence indicates that there may be pipelines that are called gathering lines but that may really be transmission lines, and that there may be gathering lines that because of size or other physical characteristics should be regulated.'' [65] Although Congress did not require DOT to regulate gathering lines, it expected DOT to obtain the necessary information to determine whether risks exist to warrant regulation, as further evidenced by the House report: ''DOT is given a great deal of discretion to implement this section based on the information it receives as it proceeds. If DOT finds that none of these lines poses a hazard to people, property, or the environment, none of them will be regulated.'' [66]

The final rule fulfills the Congressional mandate by requiring operators of all onshore gas gathering lines to file incident and annual reports under part 191. This includes pipelines that are not currently designated as Type A or Type B regulated gathering lines nor newly designated as Type C gathering lines as a result of the final rule. For clarity, this final rule designates these reporting-regulated lines as ''Type R'' gathering lines that are subject to reporting under part 191 but are not designated as regulated gathering lines in part 192. These requirements are necessary to evaluate the safety risks on gas gathering systems and determine what, if any, additional measures may be warranted to reduce those risks. As demonstrated above, it is no longer reasonable to assume rural gas gathering lines pose uniformly low risk. Information on the changing functional and operational characteristics of gas gathering lines and their safety performance is necessary for PHMSA to better understand the consequences of these changes and to set requirements for gathering lines in the future. Extension of incident and annual reporting to these additional gas gathering lines will provide PHMSA information needed for identifying—and promulgating regulatory requirements or pursuing enforcement activity—design, manufacture, installation, and operational/maintenance issues common to particular pipeline characteristics or operators.

Congress also understood that the community around gathering lines can change and authorized DOT to consider these changes when regulating gathering lines. In its report that accompanied Senate Bill 1166, the bill that became the Natural Gas Pipeline Safety Act of 1968, the Committee on Interstate and Foreign Commerce recognized that the population in an area can change, and that the statute authorized DOT to define from time to time what is a non-rural area.[67] The Committee emphasized that a ''populated area'' means not only an area with a large number of people but also areas where pipeline rights-of-way are near houses, schools, and places of employment.[68]

However, PHMSA recognizes that some reporting requirements applicable to gas transmission and regulated gathering lines may not be necessary for gas gathering lines that are not currently subject to part 192. In particular, PHMSA 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. In addition, in consideration of the comments, PHMSA is withdrawing the proposed requirement for gas gathering line operators that are not subject to part 192 to file safety-related condition reports required by § 191.23. Similarly, the final rule exempts gas gathering lines that are not subject to part 192 from the OPID validation and construction notification requirements in § 191.22(b) and (c) because such pipelines are not subject to the construction requirements in part 192.

While all gathering lines are now required to submit incident and annual reports, PHMSA is ensuring that the required data is applicable and relevant to operators of Type R gathering lines that are not subject to part 192. In consideration of comments on the NPRM and in the GPAC recommendations, PHMSA has

[63] S. Rep. 104–334, section 12 (104th Cong., 2nd Sess. 1996).

[64] H.R. Report No. 102–247(1), at 2653 (102nd Cong., 1st Sess. (1991)).

[65] *Id.*

[66] *Id.* Additionally, 49 U.S.C. 60101(b)(2)(A) specifically requires the Secretary, when defining ''regulated gathering line,'' to consider factors as location, length of line from the well site, operating pressure, throughput, and the composition of the transported gas to determine which lines are functionally gathering and should be regulated because of their physical characteristics. It reasonably follows, as evident in the Congressional record, that Congress intended that Secretary could obtain such information from operators in order to consider such factors.

[67] H.R. Rep. 90–1390, at 3234 (90th Cong., 2nd Sess. 1968).

[68] *See id.*

developed a new annual report form and a new incident report form for operators of gas gathering lines that are not subject to part 192 with more limited information that is appropriate for such facilities. For example, with regard to annual reports, PHMSA has developed an abbreviated annual report form incorporating information specifically relevant to gas gathering lines that are not currently regulated under part 192, including the decade of installation, if known. New forms and instructions are available in the public docket and will be made available on PHMSA's website at *https://www.phmsa.dot.gov/forms/operator-reports-submitted-phmsa-forms-and-instructions.*

The new annual report and incident report forms for Type R gathering lines address the GPAC's recommendations, including:

- Requiring incident location information that is equivalent to what is required for regulated gas gathering lines;
- Annual report fields appropriate for identifying and evaluating public safety and environmental risks that may be associated with unregulated gas gathering lines, including:
  - Miles by decade of installation,
  - Miles by pipeline diameter,
  - Miles by pipe material and corrosion protection status, and
  - Number of leaks repaired or scheduled for repair.
- On the Type R annual report form, allow reporting of an unknown decade of installation.
- On the Type R incident report form, allow reporting of an unknown date of installation and certain fields related to pipeline material properties and damage prevention investigations.

In the final rule, operators of previously unregulated gas gathering lines must begin submitting annual reports beginning with the first annual report cycle occurring after the endpoints of Type C or Type R gathering lines have been determined one year after the publication date of the final rule. As a result, operators of Type R and Type C gathering lines must submit a 2022 annual report no later than March 15, 2023. March 15 is the existing deadline for submitting annual reports for other gas pipeline facilities, consistent reporting deadlines reduces confusion and administrative burdens on PHMSA and operators with both Type R and regulated gas pipeline facilities. This compliance deadline represents a phase-in period well in excess of a year as measured from the publication date of the final rule.

This compliance deadline is approximately 6 months shorter than recommended by the GPAC. However, PHMSA believes that prompt submission of such reports is necessary for PHMSA's timely evaluation of whether additional regulatory efforts are needed to manage the safety and environmental risks associated with Types C and R gathering lines. PHMSA's limited information on these lines inhibits the robust understanding of their environmental and public safety risks needed to determine whether additional requirements are also warranted. The longer the delay in obtaining that information, the longer before PHMSA can diagnose and respond to a need for additional public safety and environmental protections from previously-unregulated gas gathering lines. PHMSA therefore does not believe an [18 month] compliance timeline would be overly burdensome on affected operators when evaluated against those potential safety benefits. The simplified form for Type R lines includes provisions for ''unknown'' fields to minimize burdens on gathering line operators to complete. While the Type C form is more extensive, such lines are also more likely to be more modern shale gas systems installed within the last 10–15 years. PHMSA expects the use of electronic recordkeeping and geospatial information systems is more widespread among such operators compared with traditional gathering systems and therefore expects that completing Type C annual reports will not be overly burdensome on affected entities. Finally, PHMSA notes that the compliance timeline is consistent with the approach taken in historical expansions of pipeline reporting requirements. For example, in the final rule titled, ''Pipeline Safety: Safety of Hazardous Liquid Pipelines,'' [69] PHMSA required affected operators to submit annual reports the first year after the effective date.

For similar reasons, the final rule does not include provisions for operators to request a delayed compliance deadline for the annual report requirement similar to those included in §§ 192.8 and 192.9. Additionally, most of the records necessary to prepare an annual report are also necessary in order to define the endpoints of regulated gas gathering. Operators should therefore begin collecting the necessary information immediately in order to ensure they are able to submit a complete annual report on or before the deadline in the final rule.

[69] 84 FR 52260 (Oct. 1, 2019).

B. Gathering Line Definitions—§§ 192.3 and 192.8

1. Summary of PHMSA's Proposal

PHMSA proposed to revise 49 CFR part 192 to clarify the definition of gathering lines in order to address confusion regarding how the endpoints of gathering and production are currently determined. The existing definition of gathering lines relies on language in API RP 80. In practice, however, operators and inspectors have had difficulty consistently applying the definitions that are used to define the start and endpoints of gathering in API RP 80 given the complexities in the configuration of gathering line systems in midstream operations. In addition, Federal and State enforcement of the current requirements has been hampered by the use of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system. Specifically, API RP 80 defines certain processes and equipment that may constitute a ''production operation'' but does not include defined endpoints of the production function in section 2.3 like it does for gathering in section 2.2.

This issue was raised in comments by NAPSR and others, who suggested simplifying the definition of a gas gathering line and setting clear, restrictive limits on where non-jurisdictional production operation ends and gas gathering begins. NAPSR commented in response to the ANPRM that State regulators had ''many difficulties in applying the definitions contained in API RP 80'' and recommended a simpler definition for the term gathering line. NAPSR recommended defining the end of production at the wellhead or first metering point downstream of the well. As described in the regulatory history section, PHMSA also had concerns with how the ''incidental gathering'' concept has been used to classify pipelines that perform gas transmission functions as gathering lines subject to less stringent requirements intended for small, low-pressure, traditional gathering lines.

In lieu of relying on API RP 80's definition of gathering line, the NPRM proposed new stand-alone definitions for ''onshore production facility/operation'', ''gas processing plant,'' ''gas treatment facility'', and ''gathering line (onshore)'' to determine the beginning and endpoints of each gathering line. The proposed definitions were found in § 192.3 of the NPRM and the application of those definitions was included in § 192.8. PHMSA proposed to define the end of onshore production operations as the furthermost downstream point

where measurement for the purposes of calculating minerals severance occurs or there is a comingling of the flow stream from two or more wells.

The NPRM also would have required operators to request approval from the Associate Administrator of Pipeline Safety in order to extend gathering beyond the furthermost upstream gas processing plant. Finally, in order to address PHMSA's concerns with the lack of definite limits on the application of incidental gathering, PHMSA proposed limiting the distance that a gathering line could continue beyond a defined endpoint of gathering to 1 mile, provided that it does not cross a highway or railroad right of way.

2. Summary of Public Comments

NAPSR, the Pennsylvania Public Utility Commission (PAPUC), PST, EDF, and a member of the public all expressed support for elimination of API RP 80, citing the confusion that exists in the present document for defining the endpoints of gas production and processing facilities and gas gathering lines. Some of these commenters had concerns or suggested clarifications about specific issues. For example, NAPSR and other State pipeline safety officials suggested PHMSA clarify that authority to approve extending gathering beyond the first downstream natural gas processing plant (§ 192.8(a)(2)) or to use the point of comingling on fields greater than 50 miles apart (§ 192.8(a)(3)) resides with State pipeline safety agencies in addition to the PHMSA Associate Administrator for Pipeline Safety. The PAPUC commented that PHMSA should remove the point of gas comingling (the location where gas from two or more production sites join for further transportation downstream) from the proposed definition of an onshore production operation due to concerns that operators could use that concept to classify relatively large pipelines that are performing a gathering function as non-jurisdictional production lines.

API, The American Gas Association (AGA), IPAA, GPA Midstream, the Marcellus Shale Coalition, the Oklahoma Oil and Gas Association (OKOGA), the Domestic Energy Producers Alliance, and several individual pipeline operators commented that API RP 80 adequately delineated production and gathering lines on a functional basis and should not be eliminated from part 192. Most signaled that they would be open to collaboration to improve some definitional issues, especially via changes to API RP 80 through the collaborative API standards-revision process. To this end, API suggested initiating a revision of API RP 80 instead of using the proposed wording in the NPRM. Other industry groups and operators, such as the Virginia Oil and Gas Association and the Plastic Pipe Institute, opposed any modification to the current definitions and usage of API RP 80; these commenters contended that changing the start point of gathering would violate PHMSA's statutory limitation on regulating production lines, that State agencies adequately regulate intrastate production and gathering lines, or that PHMSA had not provided sufficient safety evidence to support changes to the definition of gathering.

Industry commenters also raised a number of specific concerns regarding the replacement definitions proposed by PHMSA. The most substantive comments concerned potentially ambiguous language in PHMSA's proposed definitions for ''onshore production facility or onshore production operation'' and ''gathering line (onshore).'' API opposed the proposed definitions but suggested edits that it claimed would provide more specificity to the types of processes that could be considered production functions. API also suggested clarifications on how points of comingling are treated in the definitions of the endpoints of gathering and production and make other changes. Other commenters requested clarification that the proposed definitions of gas processing plants and gas treatment plants did not apply to facilities on gas transmission or distribution lines. Many industry commenters requested a standalone definition of ''farm taps'' to clarify the regulatory requirements applicable to service lines connected to production, gathering, and transmission lines.

Many commenters opposed PHMSA's proposal to limit the use of the ''incidental gathering'' designation to one mile from the furthermost downstream point of gathering. API proposed a standalone definition of ''incidental gathering'' consistent with the current definition in API RP 80 and suggested that if PHMSA is concerned about particular lines abusing the definition of incidental gathering, then it should designate such incidental gathering lines as regulated gathering lines rather than generally restrict the use of the incidental gathering designation in API RP 80. It further suggested that the proposed Type A, Area 2 (now Type C) requirements could address safety concerns with large-diameter, high-pressure incidental gathering lines. API further commented that requiring operators to redesignate previously unregulated incidental gathering lines as transmission lines would result in significant costs, especially if the proposed gas transmission requirements in the NPRM applied to them. GPA Midstream commented that the ''proposed limitation of one mile is too restrictive,'' and that reclassifying existing gathering lines as transmission lines would result in substantial compliance costs that need to be addressed in the RIA. However, GPA Midstream and the OKOGA suggested that a 10-mile limit was a reasonable compromise that would establishes a definite limit on incidental gathering but with enough flexibility to accommodate different system configurations.

Industry commenters also contended that the implementation timeframe for identifying and reclassifying pipelines as regulated gathering lines (6 months) was too short.

3. GPAC Recommendation

The GPAC voted 11–0, with one abstention, that the proposed rule was technically feasible, reasonable, cost-effective, and practicable, if the proposed new and revised definitions related to gas gathering in § 192.3 and the proposed changes to § 192.8(a) for determining beginning and endpoints of gathering were withdrawn. PHMSA noted during the meeting that it will monitor the outcome of the working group preparing a second edition of API RP 80 and a new document, API RP 1182, ''Safety Provisions for Large Diameter Rural Gas Gathering Lines,'' and consider whether those efforts merit potential changes to the definition of gas gathering lines in a future rulemaking. Although the GPAC discussion acknowledged PHMSA's concerns regarding the ''incidental gathering'' concept in API RP 80, the GPAC did not discuss or recommend any particular mileage limitation on that concept. Likewise, the GPAC did not make any specific recommendations regarding the terms ''onshore production facility/operation'', ''gas processing plant'', ''gas treatment facility'', or ''gathering line (onshore)''.

4. PHMSA Response

PHMSA agrees with the majority of commenters and the GPAC that definitions of ''gas processing plant,'' ''gas treatment facility,'' and ''gathering line (onshore)'' should be omitted from the final rule. After the NPRM was published, API established two committees (API RP 1182 and API RP 80) to consider revisions to API RP 80 to address the same ambiguities in those

definitions that the NPRM was intended to address. Both documents have since published. The final rule does not repeal the use of the existing definition of gathering line based on API RP 80 (1st edition, 2000) and § 192.8. PHMSA will consider updating the definitions associated with defining gathering and production lines in a separate rulemaking after evaluating the second edition of API RP 80, *Definition of Onshore Gas Gathering Lines* and new API RP 1182, *Safety Provisions for Large Diameter Rural Gas Gathering Lines.* PHMSA declines to adopt in this rulemaking API RP 1182 or the 2nd edition of API RP 80 in their entirety without providing the public an opportunity to review and comment upon those standards. A few aspects of API RP 1182 have been adapted in the final rule, these are described in section III.C. of the preamble of this final rule.

However, due to safety and enforcement concerns, the final rule defines limits to ''incidental gathering'' on new, replaced, relocated, or otherwise changed gathering lines. The final rule changes the NPRM's proposed one-mile endpoint for the designation ''incidental gathering,'' but does impose a clear and defined limitation of ten miles on ''incidental gathering'' for any such pipelines constructed after the effective date of this rulemaking. Therefore, for gathering lines installed after the effective date of the rule, the ''connection to another pipeline'' endpoint in section 2.2(a)(1)(E) of API RP 80 may not be used if the connection is ten or more miles from the endpoints of gathering defined in paragraphs (a)(1)(A) through (a)(1)(D). In other words, if an ''incidental gathering'' portion of a newly constructed pipeline would be ten or more miles in length, then the incidental gathering concept may not be used and the gathering line terminates at the furthermost downstream endpoint defined in API RP 80 sections 2.2(a)(1)(A) through (a)(1)(d), subject to the limitations in § 192.8. While PHMSA appreciates the contribution of the API RP 80 committee on these definitional issues, ''incidental gathering'' concept is a significant source of uncertainty and concern that requires an immediate regulatory remedy to protect public safety. This limitation in the final rule immediately improves regulatory certainty regarding each of the endpoints of gathering and prevents potential abuse of the incidental gathering concept pending PHMSA's consideration of the second edition of API RP 80 and operational experience gained from implementation of the definitional changes in this final rule.

The purpose of API RP 80 was to define clear endpoints to the gathering and production lines based on their function and purpose and eliminate the circular definitions in part 192 at the time. While the definitions for the end of gathering in section 2.2(a)(1)(A) through (a)(1)(D) of API RP 80 are not perfect, they provide some definite limits that are reasonably based on the function of the line in question. However, the incidental gathering concept negates both goals by allowing gathering to continue past what API itself defines as the end of gathering functions to the ''connection to another pipeline.'' This reintroduces the circular definitions in the original definition in § 192.3 that adoption of API RP 80 was intended to clarify. API RP 80 includes no limits to how far downstream the connection to another pipeline can be. As a result, PHMSA has observed supposedly incidental gathering lines that extend for several miles.

In addition to adding ambiguity to the regulations, unlimited application of incidental gathering creates a regulatory gap where long-distance pipelines that are functionally and operationally indistinguishable from transmission lines are classified as gathering lines with less stringent safety standards. By definition, an incidental gathering line is downstream of the last gathering function described in section 2.2 of API RP 80. Past that point the gas will not undergo further gathering-related processing or comingling. Incidental gathering can also include piping downstream of a major gas processing plant or a compressor used to increase downstream pressure so that the gas can be delivered to a transmission line (see section 2.2.1.2.4 of API RP 80); if that is the case, then the incidental gathering line is being operated at the same (high) pressure as the transmission line to which it is directly connected. In other words, such lines have functional and operational characteristics—including potential consequences—consistent with gas transmission lines, not production or gathering facilities. While some allowance to connect to nearby transmission facilities could be appropriate on economic or practicability grounds, this justification fades the further downstream it is applied.

In order to reduce this regulatory gap for gathering lines that are downstream of the last gathering function, the final rule limits incidental gathering to no more than 10 miles from the furthermost downstream endpoint of gathering for new, replaced, relocated, or otherwise changed pipelines. Specifically, PHMSA no longer allows the use of the ''connection to another pipeline'' endpoint in paragraph 2.2(a)(1)(E) of API RP 80 if it is 10 or more miles downstream of the furthermost of the other endpoints defined in paragraphs 2.2(a)(1)(A) through (a)(1)(D) of API RP 80. An ''incidental gathering'' pipeline installed after the effective date of the rule that extends beyond 10 miles shall be considered a transmission line, starting from the non-incidental endpoint of gathering defined in API RP 80. PHMSA currently uses a similar distance-based limit in § 192.8(a)(3) to set reasonable parameters for using the point of comingling, an actual gas gathering function, described in API RP 80 section 2.2(a)(1)(C) as an endpoint to gathering. While existing gathering lines are not affected by this change, such pipelines may be designated as Type C regulated gas gathering and subject to safety requirements, depending on their diameter, pressure, and operating environment (see sections III.C and III.D below).

Applying these limits on incidental gathering solely to only new, replaced, relocated, or otherwise changed gathering lines and revising the limit from 1 mile to 10 miles addresses the concerns raised by comments from operators while establishing a limit to incidental gathering going forward. Applicability to only new and replaced pipelines avoids disruption associated with reclassifying previously unregulated existing gathering lines as transmission lines and reduces the overall cost of the final rule for existing infrastructure. PHMSA recognizes that comments from operators broadly opposed the proposed 1-mile limit, and the GPAC did not recommend revisions to definition, including incidental gathering. However, as an alternative, a 10-mile limit was supported in public comments from GPA Midstream and OKOGA, trade associations for gas gathering line operators, and represents a reasonable first step towards establishing a firm endpoint to gathering. PHMSA also notes that a 10-mile limit on the ''incidental gathering'' concept would also be consistent with previous interpretation letters issued by PHMSA.[70] Extending the limit on incidental gathering to 10 miles provides greater flexibility for siting processing facilities and associated

[70] *See, e.g.,* PHMSA, Interpretation Letter No. PI–08–0010, Letter to State of Colorado Public Utilities Commission (Feb. 20, 2009) (endorsing use of ''incidental gathering'' concept for an 8-mile line), *https://cms7.phmsa.dot.gov/sites/phmsa.dot.gov/files/legacy/interpretations/Interpretation%20Files/Pipeline/2009/PI-09-0006.pdf.*

pipelines compared with the 1-mile limit in the proposed rule, addressing concerns raised in comments. PHMSA also notes that during this rulemaking process, there was support among both gathering line operators and public commenters to clarify the application of incidental gathering lines and impose common-sense limitations on the ''incidental gathering'' concept. Finally, as noted in the summary of comments, GPA Midstream and OKOGA submitted comments open to a 10-mile limit to incidental gathering rather than 1 mile as proposed in the NPRM.

Although the second edition of API RP 80 includes a 20-mile limitation to incidental gathering, PHMSA does not believe that newly constructed ''incidental gathering'' lines should be permitted to extend that far from a gathering facility. As explained in the NPRM, PHMSA has for more than a decade expressed concerns that the ''incidental gathering'' concept has been used to allow pipelines with certain characteristics (operating pressures, capacity, etc.)—and, consequently, risks to the public and the environment—resembling gas transmission lines to avoid part 192 regulatory requirements governing those lines. PHMSA does not, therefore, understand the 20-mile limit contemplated by API RP 80 to be as effective in capturing the safety and environmental benefits in comparison to what a more demanding mileage limitation would realize.

Further, PHMSA's discussion with various stakeholders revealed that there are very few incidental gathering lines that extend beyond 10 miles from the gathering facility; PHMSA is not aware of any, proposed new pipeline construction projects that would be classified as incidental gathering and extend 10 miles from the end of the gathering facility. The 10-mile limitation on incidental gathering, therefore, provides regulatory certainty to stakeholders, recognizes uncertainty regarding the cost impacts that could arise if incidental gathering is limited to 1 mile and on existing gas gathering lines, as proposed, and ensures that the regulatory gap that currently exists with regard to API RP 80's absence of a limitation on incidental gathering is closed for all newly constructed lines. PHMSA acknowledges that a regulatory gap remains for existing incidental gathering lines and new and replaced incidental gathering lines 10 miles or shorter. However, both new and existing incidental gathering lines with the highest potential safety hazards are either covered by existing safety standards for Type A and Type B regulated gas gathering lines in Class 2, Class 3, and Class 4 locations, or the new safety standards for Type C regulated gas gathering lines in Class 1 locations established by this final rule. These requirements are described in sections III.C and III.D. of the preamble to this final rule. PHMSA will reconsider the issue of definitions, including the endpoint of production and treatment of incidental gathering lines, in a separate rulemaking in order to ensure stakeholders are able to comprehensively comment on newly proposed definitions and the second edition of API RP 80. Infrastructure and incident data collected as a result of this rulemaking, inspection data, and the public comment process will help inform future limits to incidental gathering.

C. Expanded Scope of Gas Gathering Line Regulations—§ 192.8

1. Summary of PHMSA's Proposal

In the NPRM, PHMSA proposed to create a new category of Type A regulated gas gathering lines in Class 1 locations that had a nominal diameter of 8 inches (actual outside diameter of 8.625 inches) or greater. This new category of regulated gathering lines was identified in the table of the proposed § 192.8 as ''Type A, Area 2'' (in the final rule it is referred to as Type C), lines. PHMSA proposed to define Type A, Area 2 regulated gathering lines as gathering lines located in Class 1 locations that meet the existing Type A features in the table in § 192.9(b) (*i.e.,* metallic with an MAOP that produces a hoop stress of 20 percent or more of SMYS, or non-metallic with an MAOP greater than 125 psig) that have a nominal pipe size of 8 inches or greater.

This change was intended to improve the safety of larger-diameter, higher-stress gathering lines that were previously exempt from Federal safety regulations at part 192. In the NPRM, these newly designated Type A, Area 2 (Type C) regulated gathering lines would have to comply with a basic set of requirements as set forth in § 192.9. The specific requirements for newly regulated gas gathering lines are discussed in section III.D of this document.

2. Summary of Public Comment

API, the Michigan Public Service Commission (Michigan PSC), the Texas Pipeline Association (TPA), and Atmos Energy Corporation (Atmos) recommended that more data should be collected before determining the appropriate scope of additional regulations. The PAPUC supported the extension of regulatory oversight to gathering lines in Class 1 locations, based on its experience with growing natural gas production in Pennsylvania, noting that gathering lines are being constructed with diameters equal to or larger than typical transmission lines and are being operated at much higher pressures than was typical in the past. NAPSR supported the proposed scope of the new gathering line requirements but also commented that its members believe all gathering lines should be required to comply with part 192, regardless of class location. Some environmental and safety groups also expressed support for the extension of regulations to gas gathering lines in Class 1 locations in order to reduce the risks of incidents, greenhouse gas emissions and other air pollution. For example, EDF supported requirements for the design, installation, construction, initial inspection and testing, corrosion control, damage prevention and leakage surveys in order to reduce methane emissions.

The North Dakota Petroleum Council, the Marcellus Shale Coalition, the AGA, the Plastics Pipe Institute (PPI), Spectra Energy Partners, API, GPA Midstream, the Northeast Gas Association, and some individuals submitted comments noting issues and uncertainty with the regulatory impact assessment. For example, GPA Midstream commented that the benefits analysis included information for offshore and Class 2 incidents that are not applicable to the proposed scope of this final rule and 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. Many operators and industry groups expressed disagreement with applying regulations to all Class 1 gas gathering lines with outer diameters of 8.625 inches or greater, arguing that gathering lines on the smaller end of that category do not represent the large-diameter, high-pressure gathering lines referenced in the preamble of the NPRM and public discussions. API commented that if PHMSA does proceed with defining a new category of regulated gathering lines, gathering lines with outer diameter greater than 16 inches have the potential to pose a higher risk and should be the criteria for determining regulated gathering, rather than 8 inches. API further suggested that targeting lines with outer diameters greater than 16 inches would be more in the spirit of the risk-based philosophy of other parts of the code, such as integrity management. This suggestion was

repeated by GPA Midstream, the North Dakota, Petroleum Council, and others.

A number of commenters representing the pipeline industry expressed concerns with the deadlines to identify newly regulated gathering lines and then comply with the proposed regulations. For example, Rice Energy, Dominion East Ohio, API, and GPA Midstream commented that the implementation timeframe for identifying proposed Type A, Area 2 (now Type C) regulated gathering lines was too short. Industry commenters were especially concerned about the deadline to establish an MAOP, especially if the MAOP verification requirements proposed for gas transmission lines in the NPRM also applied to gathering lines. One commenter suggested an economic criterion to allow an exemption for operators of economically marginal, low stress gathering lines.

Some commenters expressed the view that the proposed Type A, Area 2 (now Type C) classification for newly regulated gas gathering lines could be confusing. Specifically, commenters found that designating newly regulated gas gathering lines as Type A, Area 2 (now Type C), and then requiring those pipelines to follow requirements similar to Type B rather than existing Type A requirements was cumbersome and risked conflating distinct regulatory requirements. A few commenters suggested a Type C designation rather than the proposed Type A, Area 2 (now Type C) designation. The GPAC recommended PHMSA address these concerns in the final rule.

3. GPAC Recommendation

GPAC voted 11–1 that the scope of newly regulated gas gathering lines in proposed § 192.8(b) and (c) is technically feasible, reasonable, cost-effective, and practicable if PHMSA considered the following:

- Establishing an initial framework for regulating Class 1 gathering lines that could be built upon in light of future information and experience;
- Setting a minimum set of requirements for gathering lines 8.625 inches in outside diameter and greater (considering, for example: Damage prevention; line markers; public awareness; leak surveys and repairs; design, installation, construction, and initial inspection and testing for new lines; and emergency plans). Give due consideration to the GPAC discussion on the costs and benefits of performing leakage surveys;
- Consider applying a PIR concept and additional requirements to provide safety and environmental protection for larger- diameter gathering lines (*e.g.,* greater than 12.75 inch outside diameter); and
- Ensuring that composite pipe [71] was adequately addressed to minimize the impact on its continued use. Note that this is discussed in section III.D below.

4. PHMSA Response

In response to public comments and the recommendations of the GPAC, PHMSA has changed the proposed ''Type A, Area 2'' designation for newly regulated gas gathering lines to ''Type C'' lines. PHMSA originally proposed use of the term ''Type A, Area 2'' (now Type C) because the newly regulated gas gathering lines have features similar to existing Type A pipelines in the table in § 192.8, except that they are located in Class 1 locations. However, PHMSA agrees that creating the category ''Type C'' may be less confusing. While adopting the new designation of Type C regulated gas gathering lines introduces some repetition in the table in § 192.8, PHMSA believes it will make clearer that the three categories represent different levels of risk that warrant corresponding levels of regulation and will reduce unnecessary confusion among operators and inspectors in the future.

The final rule continues to define Type C regulated gas gathering lines as gas gathering lines in Class 1 locations that are 8.625 inches or greater in diameter and are: (1) Metallic, with an MAOP producing a hoop stress of 20 percent or more of SMYS; (2) metallic, with an MAOP greater than 125 psig if the hoop stress is unknown; or (3) non-metallic, with an MAOP greater than 125 psig. However, PHMSA recognizes that not all gathering lines that meet these criteria pose the same level of risk. Therefore, the final rule provides that the requirements that Type C gathering lines must comply with will vary, based on the scale of risk associated with the particular characteristics of the pipeline. The applicability of each of the requirements that potentially applies to Type C lines is described in section III.D below and the section-by-section analysis. Gathering lines smaller than 8.625 inches in outside diameter or operating below the pressure or stress level criteria described above will remain unregulated under part 192 and are subject only to incident and annual reporting in part 191 (see section III.A below).

As described in the background section (II.A) above, modern gathering systems require larger, higher-pressure lines to meet the new supply and demand pressures than had been common when the existing requirements were put into place. This is not a theoretical problem: Failures on unregulated gas gathering lines have resulted in serious incidents, some with fatal consequences (see the discussion in section II.A above).

PHMSA appreciates the need to exercise caution in exercising its statutory authority to regulate gathering lines that have not been previously covered by parts 191 and 192 without clear, detailed safety data. This is why a new category of gathering lines is being created for reporting purposes only that are only subject to the incident and annual reporting requirements described in section III.A of this document. These are designated as ''Type R'' gathering lines in § 192.8. These lines are not regulated gathering lines under in part 192 but are subject to incident and annual reporting requirements in part 191.

However, there is ample basis upon which to add the targeted requirements in this final rule for Type C gathering lines that mirror the requirements already in place for existing, lower-stress Type B lines. These measures are an appropriate initial step to ensure basic safeguards to the public, property, and the environment while additional data is collected and analyzed. Additionally, withdrawing the proposed regulations in the NPRM for previously unregulated gas gathering lines in its entirety would be inconsistent with public safety and would not be responsive to GAO recommendation GAO–14–667 or the Congressional mandate in the 2020 PIPES Act. Therefore, PHMSA is adding the definition of Type C regulated gas gathering lines as proposed in the NPRM.

However, the new regulatory requirements are tailored to the potential hazards the newly regulated gathering lines may pose. This is described in more detail in section III.D below. PHMSA determined that certain programs, such as damage prevention, are foundational to pipeline safety and public trust and therefore should be required for all Type C gas gathering lines as originally proposed in the NPRM. However, other requirements apply only to Type C lines with an outside diameter greater than 16 inches, and Type C lines with an outside

[71] A composite pipe is made of a combination of either steel or plastic with a reinforcing material designed to maintain its circumferential and longitudinal strength. A common configuration consists of steel or fiber reinforcement layered between a polymer inside liner and outer shell. No composite materials are currently authorized for use in part 192 or part 195, but may be used through a special permit (*see* § 190.341).

diameter larger than 12.75 inches that are located near homes and other structures. The largest-diameter gas gathering lines and those that can directly impact local communities are required to comply with all of the requirements for newly regulated Type C (Type A, Area 2) gathering lines proposed in the NPRM. The proposed deadline to determine endpoints of newly regulated gathering lines remains unchanged in the final rule—6 months after the effective date. Operators must therefore identify the endpoints of newly regulated Type C lines on or before November 16, 2022. While the GPAC recommended a 2-year compliance deadline for identifying the endpoints of Type C gathering lines, such a delay is not necessary given that PHMSA understands that many Type C lines are of more recent vintage and therefore would generally have more robust records to facilitate determination of endpoints than older gathering lines. A prolonged identification period would also delay the important safety (section III.D. *infra*) and reporting (section III.A.4. *supra*) standards in the final rule. The Type C determination in § 192.8(c)(2) requires, at a minimum, knowledge only of the location, diameter, and pressure of the pipeline. Most Type C gathering lines are relatively modern shale gas systems and these basic records should be readily accessible.

PHMSA acknowledges that this deadline may be challenging for some operators of certain older, smaller-diameter, systems. The final rule therefore includes procedures for an operator to request an alternative compliance deadline with a notification in accordance with § 192.18. This is intended to mirror existing § 192.9(e)(2), which gives the PHMSA Administrator discretion to allow a later deadline if justified in a particular case. An operator must submit a written request to PHMSA in accordance with § 192.18 no later than 90 days prior to the standard compliance deadline. The request must include, at a minimum, a description of the facilities that require a delayed compliance date, the justification for an alternative compliance deadline, and the proposed alternative compliance deadline. An operator may proceed with their proposed compliance deadline if they receive a no-objection letter from PHMSA or if PHMSA does not reply within 90 days. If delayed identification impacts an operator's ability to comply with the requirements in § 192.9, they must submit a separate notification to request delayed compliance under that section.

The combination of changes discussed in this section and in section III.D below provides a reasonable and cost-effective initial approach to address the risks associated with previously unregulated gas gathering lines. PHMSA will monitor the safety performance of both newly regulated gas gathering and unregulated gas gathering lines and evaluate the need for further regulatory action in the future.

D. Safety Requirements for Newly Regulated Gas Gathering Lines—§§ 192.9, 192.13, 192.18, 192.452, and 192.619

1. Summary of PHMSA's Proposal

PHMSA proposed in the NPRM to apply part 192 safety requirements to the newly-established Type A, Area 2 lines (referred to as Type C lines in the final rule). These requirements, collectively referred to as Type C requirements in this final rule, are:

- § 192.9(d)(1)—Implement design, installation, construction, initial inspection, and initial testing requirements for new/replaced/relocated/changed lines in accordance with the requirements in part 192 for transmission lines.
- § 192.9(d)(2)—Adopt corrosion control measures for metallic pipe in accordance with part 192, subpart I, requirements for transmission lines.
- § 192.9(d)(3)—Adopt damage prevention measures in accordance with § 192.614.
- § 192.9(d)(4)—Develop public awareness programs in accordance with § 192.616.
- § 192.9(d)(5)—Establish MAOP in accordance with § 192.619.
- § 192.9(d)(6)—Install and maintain line markers in accordance with the requirements for transmission lines in § 192.707.
- § 192.9(d)(7)—Conduct leakage surveys in accordance with § 192.706, using leak- detection equipment and promptly repair hazardous leaks that are discovered, in accordance with § 192.703(c).
- § 192.9(d)(8)—Develop and implement procedures for emergency plans in accordance with § 192.615.

These requirements are the same as those that currently apply to Type B regulated gas gathering lines, except for the new emergency plans requirements. PHMSA also proposed conforming changes to §§ 192.13, 192.452, and 192.619.

2. Summary of Public Comment

Citizen and environmental groups expressed support for the proposed requirements for newly regulated gas gathering lines or suggested additional requirements. Several citizen groups suggested that gas gathering lines that function similarly to transmission lines should be regulated like transmission lines in part 192. Similarly, the Public Service Commission of West Virginia commented that the proposed requirements for Type A, Area 2 (now Type C) lines, which mirror the requirements for low-pressure, low-stress Type B gathering lines, are not adequate or sufficient to ensure the safety of large, high-pressure gas gathering lines and instead recommended that such pipelines follow existing Type A, Area 1 requirements (*i.e.* most gas transmission line requirements) that apply to other regulated gathering lines that operate with higher stress levels and pressures.

GPA Midstream and Kinder Morgan commented that Type A, Area 2 (now Type C) lines should not have to conduct leakage surveys with leak detection equipment, as currently required for Type B gathering lines in § 192.9(d)(7), since leaks and ruptures on higher-stress Type A lines are easier to detect without specialized equipment. API and TPA proposed that the emergency-planning requirements in § 192.9(d)(8) be revised to reference the existing requirements for other types of pipelines in § 192.615. They also recommended exempting operators of Type A, Area 2 (now Type C) regulated gathering lines from the requirement to have written procedures to respond to each of the emergency situations listed in § 192.615(a)(3), presumably for cost concerns. API, GPA Midstream, and Northeast Gas Association commented that the compliance cost estimates used in the RIA for Type A, Area 2 (now Type C) regulated gathering lines were underestimated and contained erroneous assumptions. For example, GPA Midstream raised concerns about the costs of program evaluation requirements under public awareness. Industry commenters were especially concerned about the applicability of the proposed gas transmission requirements in the NPRM such as the MAOP reconfirmation, including the cost to establish MAOP and confirm the material properties of gathering lines that were not previously required to have an MAOP or keep such records. PHMSA notes that these provisions were finalized by the Gas Transmission Final Rule and apply only to gas transmission lines.

A number of commenters articulated concerns about how the proposed regulations would affect the use of non-metallic materials in previously

unregulated gathering systems. Commenters representing gathering line operators and non-metallic pipe manufacturers urged PHMSA to consider the impact of the rule on gathering lines made of composite materials and polyethylene pipe manufactured to standards other than ASTM D2513. A composite pipe is made of a combination of either steel or plastic with a reinforcing material designed to maintain its circumferential and longitudinal strength. A common configuration consists of steel or fiber reinforcement layered between a polymer inside liner and outer shell. No composite materials are currently authorized for use in part 192 or part 195 but may be used through a special permit (see § 190.341).

Commenters were especially concerned with the possibility that existing, unregulated lines made of non-metallic materials would need to be replaced if they subsequently become regulated Type A, Area 2 (Type C) lines. API suggested that PHMSA incorporate by reference two standards, API Standard 15S, ''Spoolable Composite Pipe Systems,'' 1st edition and ASTM F2619/F2619M–13, ''Standard Specification for High-Density Polyethylene (PE) Line Pipe'' into § 192.9 to allow the use of composite materials and an alternative specification for polyethylene pipe that is commonly used in unregulated production and gathering operations. API and the Plastic Pipe Institute commented that the proposed repair criteria in the NPRM did not address non-metallic materials and could effectively eliminate the use of plastics and composites in Type A, Area 2 (now Type C) lines that previously had no such restrictions. GPA Midstream also commented that composite pipe can operate at pressures that would include them within the Type A, Area 2 (now Type C) criteria and should therefore be addressed in the rule.

3. GPAC Recommendations

GPAC voted 12–0 that the proposed minimum safety standards for Type A, Area 2 (Type C) regulated gathering lines were technically feasible, reasonable, cost-effective, and practicable, if the following changes were made:

- Extend the deadline for Type A, Area 2 (Type C) gathering lines that become regulated in the future due to new dwellings to comply with part 192 requirements from one year to two years after the effective date of the final rule;
- Add a notification process similar to the process endorsed by the committee for the gas transmission rule[72] to address the use of composite pipe materials in existing and new Type A, Area 2 (Type C) gathering lines;
- Extend the deadline in § 192.8(b) for determining if pipelines are classified as Type A, Area 2 (Type C) gathering lines from six months to two years after the effective date of the final rule;
- Extend the deadline for newly regulated gas gathering lines to comply with Type A, Area 2 (Type C) requirements to three years after the effective date of the rule, and make conforming changes (§§ 192.9(e)(3) and (4), 192.452, 192.13, and 192.619);
- Ensure that the language for designating newly regulated gas gathering lines is as clear as possible (*e.g.,* Type C vs. Type A, Area 2);
- Allow operators of Type A, Area 2 (Type C) gas gathering lines to establish MAOP based on a five-year high operating pressure; or via an alternative method with notification to PHMSA (§ 192.18 process); and
- Modify § 192.9 (d) to include Type A, Area 2 (Type C) gathering lines.

4. PHMSA Response

PHMSA understands the concerns expressed by the commenters regarding the application of existing pipeline safety requirements to newly regulated gas gathering lines. While the final rule does not significantly change the NPRM's proposed criteria for designating newly regulated Type C gas gathering lines (higher stress gathering lines with an outside diameter of 8.625 inches or greater, see section III.C), it does make changes to the NPRM's proposal regarding how each of the proposed Type C requirements are to be applied. These changes focus on applying more requirements to the highest-risk, largest-diameter gathering lines. The risk-based approach to Type C requirements in this final rule is based upon discussions at the June 25th GPAC meeting, consideration of the public comments received on the NPRM, and an analysis of the costs and benefits of various alternatives (see the RIA, available in the docket for this rule, for a detailed description of alternatives considered). As discussed during the GPAC meeting, PHMSA emphasizes that the Type C requirements are an initial step in addressing safety concerns with larger-diameter gas gathering lines. If PHMSA's analysis of the safety performance of regulated and unregulated gathering lines demonstrates a need to revise the requirements for regulated gathering lines, PHMSA can exercise its authority to do so in a future rulemaking.

The applicability of each of the requirements for Type C regulated gas gathering lines in the final rule is as follows:

Requirements for Type C gathering lines with outside diameters of 8.625 inches and greater:

- Design, installation, construction, and initial inspection and testing for lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13 per transmission line requirements in part 192;
- Corrosion Control (part 192, subpart I);
- Damage Prevention Program (§ 192.614);
- Emergency Plans (§ 192.615);
- Public Awareness (§ 192.616);
- Line Markers (§ 192.707); and
- Leakage Surveys (§ 192.706).

Additional requirements for Type C gathering lines with outside diameters greater than 12.75 inches:

- Applicable requirements of part 192 for plastic pipe and components; and
- Establishment of MAOP (§ 192.619).

Exception: Gathering lines with an outer diameter 16 inches or less that are not located within a potential impact circle containing a building intended for human occupancy or other impacted sites must only comply with requirements governing damage prevention (§ 192.614); emergency plans (§ 192.615); and, for Type C lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13 (*i.e.* 1 year after the effective date of the rule), certain design, installation, construction, initial inspection, and initial testing requirements applicable to transmission lines under part 192. These provisions are required for all Type C gathering lines regardless of size or location. The applicability of each of these requirements is summarized in the table below:

[72] This recommendation was subsequently codified as § 192.18 by the Gas Transmission Final Rule (84 FR 52180).

Outside diameter	*Not* located near a building intended for human occupancy or other impacted site (§ 192.9(f))	Located near a building intended for human occupancy or other impacted site (§ 192.9(f))
Greater than or equal to 8.625 inches up to and including 12.75 inches.	—Design, Construction, Initial Inspection and Testing (new/replaced/relocated/changed lines). —Damage Prevention —Emergency plans	—Design, Construction, Initial Inspection and Testing (new/replaced/relocated/changed lines). —Corrosion Control. —Damage Prevention. —Emergency Plans. —Line Markers. —Public Awareness. —Leakage Surveys.
Greater than 12.75 inches up to and including 16 inches.	—Design, Construction, Initial Inspection and Testing (new/replaced/relocated/changed lines). —Damage Prevention. —Emergency Plans.	All Type C Requirements.
Greater than 16 inches	All Type C Requirements	All Type C Requirements.

The potential impact circle calculation criterion for certain Type C requirements is based on the method for identifying high-consequence areas in the gas transmission integrity management program regulations in subpart O of part 192. Specifically, the terms ''potential impact circle'' and ''potential impact radius (PIR),'' including the formula for calculating what the length of the potential impact radius,[73] are defined in § 192.903. The ''potential impact circle'' is the area around a pipeline where a pipeline rupture could cause severe consequences, such as casualties and destruction of property. PHMSA notes that the formula requires knowing the MAOP of the pipeline, rather than the actual operating pressure. Additionally, the final rule requires that operators of Type C gathering line use a factor of 0.73 for wet/rich natural gas in the PIR calculation rather than the 0.69 factor for dry natural gas used in the integrity management regulations. This results in a slightly larger potential impact circle reflecting the potentially more intense fire and explosion hazards due to the higher average energy content of unprocessed gas, which may contain higher concentrations of natural gas liquids and other hydrocarbons. A 2005 report prepared for PHMSA by Michael Baker Jr., Inc., titled, ''Potential Impact Radius Formulae for Flammable Gases other than Natural Gas Subject to 49 CFR 192'' [74] calculated that 0.73 was an appropriate PIR factor for pipelines transporting rich natural gas. The calculations are detailed in section 4.8.4 of the report using the same formula described in ASME B31.8S that is referenced in the gas transmission integrity management regulations. API RP 1182 uses the same factor for a similar PIR concept, however that document is not incorporated by reference in this rule. Similarly, § 192.9(f) in this final rule dictates that any Type C gathering line segment located within a potential impact circle containing a building intended for human occupancy or other impacted site must comply with all Type C requirements applicable for the diameter of that line, since a failure on that segment has the potential to cause catastrophic damage to local communities. This approach was discussed at the GPAC and in public comments and PHMSA agrees it is an effective way of prioritizing short-term regulatory action towards gas gathering lines with the highest potential consequences of a failure.

PHMSA recognizes that not all operators may be able to perform the potential impact radius calculation. If the gathering line segment does not have an established MAOP or other records necessary to perform the PIR calculation, the operator may perform the same determination on a class location unit (see § 192.5) basis rather than a potential impact circle basis. A class location unit is 1 mile in length and extends 220 yards on either side of the centerline of a pipeline. PHMSA notes that this uses the same ''sliding mile'' approach used for determining class locations rather than static mile-long increments stacked end-over-end. The class-location unit moves along the pipeline, and if the sliding mile contains a building intended for human occupancy or other impacted site at any point during the mile's movement, then the exception in paragraph (f) does not apply for the entire mile of pipeline contained within the sliding mile.

The class location unit method for applying these exceptions is used in API RP 1182 and provides a simpler, more conservative method for determining the applicability of the § 192.9(f) exception for operators that choose not to perform a PIR analysis or lack records of the parameters necessary to calculate the PIR. PHMSA expects that the class location unit method will result in fewer miles of gathering lines being covered by the § 192.9 exception in almost all circumstances because the additional requirements will apply for a mile on each side of a building intended for human occupancy or other impacted site. Theoretically, the PIR of a pipeline could exceed 220 yards; if this is the case it is possible that some structures could be captured by the PIR analysis but not the class location unit analysis. However, given that this exception is limited for Type C gathering lines 16 inches or less in outside diameter, it is unlikely that a gathering line 16 inches or less in diameter will operate at a pressure that would cause the calculated PIR to exceed the width of the class location unit. The MAOP of a pipeline with an outside diameter of 16 inches must exceed 3000 psig for the PIR of the pipeline to exceed 660 feet. A MAOP of 3000 psig is unusually high. Although PHMSA does not collect data on MAOP on annual reports, incident reports reveal that less than 1 percent of gas transmission incidents from 2010 through the end of 2021 involved a facility with an MAOP higher than 3000 psig; further, there were no incidents volving a pipeline larger than 10.75 inches in outside diameter, and no incidents on regulated onshore gas gathering lines.

In the final rule, operators must achieve compliance with applicable Type C requirements no later than 1

[73] *See* ASME B31.8S for additional information on calculating PIR.

[74] Michael Baker Jr., Inc. ''TTO Number 13: Potential Impact Radius Formulae for Flammable Gases Other than Natural Gas Subject to 49 CFR 192: Final Report'' (June 2005), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-transmission-integrity-management/65311/tto13potentialimpactradiusfinalreportjune2005.pdf.*

year after the effective date of the rule, unless PHMSA has approved an alternative compliance schedule after the operator has submitted a notification in accordance with § 192.18. This is a shorter compliance deadline than the 3-year phase in recommended by the GPAC (*i.e.,* 1-year after the endpoints of Type C have been identified). The safety standards in the final rule target known threats to public safety, and the most significant requirements are targeted at gathering lines with direct potential safety impacts (*i.e.,* has a potential impact circle containing a building intended for human occupancy). Due to these direct threats to the public, it is critical that operators implement minimum safety practices as soon as practicable. The final rule provides operators a total of 1½ years from the date of publication to implement these measures, which should be achievable for most operators.

However, PHMSA recognizes that some operators may encounter challenges in meeting the deadline for one or more of the Type C requirements. The final rule therefore includes procedures for an operator to request an alternative compliance deadline with a notification in accordance with § 192.18. This is intended to mirror existing § 192.9(e)(2), which allows the PHMSA Administrator flexibility to provide a later deadline if justified in a particular case. An operator must submit a written request to PHMSA in accordance with § 192.18 no later than 90 days prior to the standard compliance deadline. The request must include, at a minimum, a description of the facilities that require a delayed compliance date, the proposed alternative deadline, justification for the alternative compliance deadline, and actions the operator will take to ensure the safety of the affected facilities in the interim. The description of the pipeline facility and the operating environment should include relevant information about the integrity of the pipeline and the potential consequences in the case of the release. This includes: The diameter of the pipeline; the operating pressure; known design and construction specifications; results from surveys, patrols, or integrity assessments; and the presence of homes or other human uses near the pipeline. An operator may request an alternative compliance schedule for more than one requirement within § 192.9(e) in a single notice. However, the notice must include a proposed compliance schedule and justification for each requirement. An operator may proceed with their proposed compliance deadline if they receive a no-objection letter from PHMSA or if PHMSA does not reply within 90 days.

Consistent with the deadlines described above, design, construction, initial inspection, and initial testing requirements apply to all Type C lines that are new, replaced, relocated, or otherwise changed after the applicable compliance deadline in § 192.13 (*i.e.,* 1 year after the effective date of the rule). Additionally, in the final rule, operators of unregulated gas gathering lines that become Type C regulated gathering lines, or become subject to additional Type C requirements, due to a change in the pipeline's MAOP or the discovery of a building intended for human occupancy or other impacted site have 1 year from the time the change is discovered to comply with Type C requirements.

PHMSA determined that it was appropriate for all Type C gathering lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13 (*i.e.,* 1 year after the effective date of the rule) to comply with the initial design, construction, inspection, and testing requirements applicable to transmission lines in part 192 to ensure that new, higher risk gathering lines are adequately designed and constructed. PHMSA also determined that it was appropriate for all Type C gathering lines to comply with damage prevention and emergency plan requirements in §§ 192.614 and 192.615, based on the incident history of transmission pipelines and fatal gas gathering incidents. For onshore gas transmission lines between 2010 and 2019, excavation damage was the third leading cause of incidents and the most common cause of incidents that resulted in fatal injuries.[75] As described in section II.A, many of the fatal incidents on unregulated gathering lines described in media reports have been caused by excavation damage. These incidents commonly cause serious and fatal injuries regardless of the diameter or location of the pipeline since equipment operators and other workers may be in close proximity to the point of failure. However, effective damage prevention programs and participation in One-Call programs can reduce this risk. Based on gas transmission line incident report data, both the number of excavation damage incidents and the share of incidents caused by excavation damage has trended downwards between 2000 and 2018. While gathering lines are covered under damage prevention and One-Call laws in most States, PHMSA expects that requiring operators to implement a damage prevention program under part 192 may improve enforcement of these requirements and cover lines in States where gathering lines are excepted. Maintaining a written damage prevention procedure and communicating damage prevention information to the public may also result in safety benefits beyond compliance with State One-Call laws from operators and excavators becoming more cognizant of the risks of third-party damage to gathering lines.

The requirements for emergency plans in § 192.615 directly address concerns with operator and community emergency response and planning capability. Emergency response plans and procedures for rural gathering lines were areas of emphasis in GAO's August 2014 report on safety requirements for transporting energy products.[76] In that report, the NTSB, a representative of the National Association of State Fire Marshals and emergency response officials agreed that ''emergency response plans are critical for pipeline safety;'' however, those emergency officials were concerned that responders in rural areas lacked the information about unregulated gathering lines in their communities to prepare for and respond to pipeline emergencies. Requiring all Type C gathering lines to comply with § 192.615 addresses these concerns by bringing emergency planning requirements for such pipelines in line with existing requirements for gas transmission lines.

PHMSA disagrees with the comment that Type C gas gathering lines should be excepted from the requirement to develop and follow procedures for responding to common types of pipeline emergencies listed in § 192.615(a)(3), such as gas leaks in structures, fires, explosions, and natural disasters. This requirement is necessary to help ensure effective emergency preparedness. As described in the background section II of this document and the GAO–14–667 report, emergency response capabilities are especially important for gas gathering systems operating in communities that do not have experience with intensive oil and gas development.

Design, installation, construction, initial inspection, and initial testing

[75] Out of 1,057 incidents reported to PHMSA that occurred during this period, 150 were due to excavation damage. Of the 13 incidents that resulted in fatal injuries, 6 were caused by excavation damage.

[76] GAO, 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. 2012).

requirements, and corrosion control measures in part 192 are intended to reduce the likelihood of a release caused by material and equipment failure, corrosion, and excavation damage. Design, installation, construction, initial inspection, and initial testing requirements are prospective only. Operators are not expected to replace facilities existing on or prior to the compliance deadline in § 192.13 (*i.e.,* 1 year after the effective date of the rule) in order to comply with these requirements. PHMSA expects there will be safety benefits from applying part 192 design, construction, initial inspection, and initial testing requirements should those existing lines require replacement, relocation or otherwise be changed.

In the NPRM, PHMSA did not intend to prohibit the use of composite pipe materials on previously unregulated Type C gathering lines or require the removal of such materials. However, the existing part 192 requirements were written for steel or conventional plastic pipe. Additionally, the NPRM did not propose to incorporate by reference API RP 15S or F2619/F2619M–13 and PHMSA has not yet conducted the technical review of those documents needed to support their incorporation by reference in this final rule.

To address composite pipe, PHMSA has added a provision in the final rule to allow operators to install or replace composite pipe that is not otherwise authorized by part 192 for use in regulated Type C gas gathering lines upon notification to PHMSA pursuant to §§ 192.9(h) and 192.18. Operators may use composite pipe or materials as proposed in their notification if, after 91 days, they have not received a letter from PHMSA with either an objection to the proposed use of composite pipe, or that states that PHMSA requires additional time to conduct its review. PHMSA may also proactively issue a no-objection letter. Additionally, operators may continue to use composite pipe installed on or before the effective date of the rule; no notification under §§ 192.9(h) and 192.18 would be required in those circumstances. This change affects Type C gathering lines only and does not authorize the use of composite pipe for any other type of pipeline covered under part 192. Under the § 192.18 notification process, PHMSA will evaluate the operator's proposed operation and maintenance procedures, which includes the operator's proposed remediation methods and procedures for identifying defects and determining the safe operating pressures of composite pipe when defects are found. PHMSA will not approve notifications that it determines are inconsistent with pipeline safety. An objection letter issued under § 192.18 will not foreclose an operator's ability to seek a special permit in accordance with § 190.341. Additional information on this process is provided in the section-by-section analysis of this document. PHMSA may use data obtained from observing the design, construction, and operation of composite materials in Type C gathering lines to inform its future decisions on whether and how to accept composite materials for pipelines in other jurisdictional applications.

Public awareness requirements in § 192.616 and line marker requirements in § 192.707 apply to Type C lines that are located near buildings intended for human occupancy, and further address residual risks despite part 192 damage prevention and emergency planning requirements. Public awareness requirements in § 192.616 require additional communication with excavators, first responders, local governments, and the public. Notably, this provision at § 192.616(d) obliges operators to describe the potential hazards of a pipeline release, the physical markers of a release, and how to respond to customers and other members of the community. This requirement is especially important for members of the public to identify dangerous releases on gas pipelines that are not odorized. These communications improve safety by encouraging individuals to take safe actions such as contacting One-Call before performing excavations and recognizing, avoiding, and reporting gas leaks. Section 192.707 requires the placement of line markers at road and railroad crossings, and wherever else the operator deems is necessary. These markers provide a visual reminder of the presence of otherwise invisible pipelines and serve to reduce third-party damage risks. Additionally, during emergencies, line markers communicate hazards and operator contact information to first responders.

After consideration of public comments, the recommendations of the GPAC, and the final RIA that accompanies this final rule, PHMSA has retained the requirement for leakage surveys in § 192.706 for both (1) all Type C gathering lines with an outside diameter greater than 16 inches, as well as (2) Type C gathering lines with an outer diameter greater than 8.625 inches but not exceeding 16 inches in outside diameter that are located in a potential impact circle containing a building intended for human occupancy or other impacted site. In other words, this requirement applies to larger-diameter gas gathering lines and those that could directly impact nearby structures and people during a rupture. Since Class 1 gas gathering lines are not typically odorized and the leakage survey requirement applies to larger diameter Type C gathering lines or those located near people, PHMSA has retained the requirement that operators use leak detection equipment when conducting leakage surveys. Leak detection equipment is already required for leakage surveys on gas transmission lines that are not odorized.

Part 192 does not currently establish technology or performance standards for leak detection equipment, and the NPRM did not propose to establish standards for leak detection equipment. The final rule therefore does not specify what constitutes ''leak detection equipment.'' Any equipment capable of detecting all leaks on the pipeline system would be acceptable.[77] Traditionally, operator personnel perform an instrumented leakage survey by walking along the pipeline right-of-of way with handheld leak detection equipment, such as a flame ionization detection device, laser-based methane detector, or other equipment. Similar equipment can be installed on vehicles or at fixed locations along the right of way. Some technology providers claim to detect smaller leaks from greater distances using a combination of vehicular or aerial sensor platforms, sensitive gas detectors, other sensors, and analytics. There are also various methods for continuous leak monitoring, including pressure and pressure wave monitoring, fixed gas detectors, and fiber optic-based distributed sensing. Performing leakage surveys increases the likelihood that small defects are discovered and remediated before they evolve into more significant failures with potentially severe impacts to people, nearby structures, and the environment. Leakage surveys are also necessary to mitigate the climate change impacts of methane leaks.

Lastly, consistent with the GPAC recommendations, PHMSA adopts the remaining requirements proposed in the NPRM for application to all Type C lines with an outside diameter of greater than 16 inches, and Type C lines with an outside diameter greater than 12.75 inches but not exceeding 16 inches in outer diameter, that are located near buildings intended for human

[77] *See, e.g.,* PHMSA, Interpretation Letter No PI–01–0104, Letter to Richard Motsinger (Apr. 3, 2001), *https://www.phmsa.dot.gov/regulations/title49/interp/PI-01-0104.*

occupancy or other impacted sites. For example, MAOP determinations will also be required for Type C gathering lines with an outside diameter greater than 16 inches, and Type C lines larger than 12.75 inches in outside diameter up to and including 16 inches in outside diameter that are located in a potential impact circle containing a building intended for human occupancy or other impacted sites. The amendments proposed in the NPRM to the tables in § 192.619(a)(3) that would give existing Type C gathering lines the option of establishing an MAOP based on historical operating pressure have been incorporated into the final rule. Therefore, newly regulated Type C lines now will have the option of establishing MAOP using the highest actual operating pressure to which the segment was subjected during the five years (60 months) preceding the effective date of the rule, or five years (60 months) before first becoming subject to the rule, whichever is later.

However, PHMSA supports the GPAC recommendation to allow operators of Type C gas gathering lines to establish MAOP using alternative methods pursuant to the notification process set forth in § 192.18 and the requirements of § 192.619(c)(2). PHMSA is persuaded that allowing alternative methods with PHMSA approval under § 192.18 for establishing the MAOP of a previously unregulated Type C gas gathering line existing on or before the effective date of the rule is appropriate. Such operators were not previously required to make and maintain records of MAOP, pressure tests, or operating pressure and may not have traceable, verifiable, and complete records necessary to calculate an MAOP using the lowest of each of the methods listed in § 192.619. This final rule includes a new § 192.619(c)(2) and conforming changes to § 192.18 to allow an operator of an existing Type C regulated gathering lines based on available records. Under this process, the operator would propose an MAOP based on the information available about the pipeline, such as actual highest operating pressure, operational and maintenance history, pressure test records, and information about the design and material properties of the pipeline. The new paragraph specifies the minimum information required to be submitted to PHMSA in the notification. The ''no objection'' process in § 192.18 requires PHMSA to respond within 90 days. If, after 90 days, PHMSA has not responded to the notification, the operator would be allowed to use the ''other technology'' method to establish MAOP. This approach is not permitted for natural gas pipeline facilities other than Type C regulated gathering lines.

The risk-based application of each of these Type C requirements is based on the operational and functional characteristics of those lines and strikes an appropriate balance between the need to protect people and the environment from the risks associated with large-diameter, high-pressure gathering lines and the need to exercise caution imposing regulatory burdens before more detailed information can be collected. The most substantive requirements apply to all Type C gathering lines with outer diameter of more than 16 inches and Type C gathering lines larger than 12.75 inches up through and including 16 inches that could directly affect homes, businesses, and other building intended for human occupancy. This approach focuses more stringent compliance measures on gas gathering lines that pose the most significant potential hazard to people and the environment. The requirements that remain for Type C gathering lines with an outside diameter of 12.75 inches or less include initial design, construction and testing requirements, leakage surveys emergency planning, damage prevention, and corrosion control. While the GPAC recommended PHMSA consider applying leakage survey requirements to all Type C gathering lines, PHMSA has concluded that more detailed information on the extent and safety performance of such pipelines is needed to justify applying those requirements for Type C lines 16 inches in outside diameter and smaller that do not have a building intended for human occupancy within the PIR. However, as discussed at the GPAC meeting and in this final rule, PHMSA will use the data collected from the new reporting requirements to evaluate continuously PHMSA's oversight of gas gathering lines and determine if additional requirements are appropriate in the future.

There is no potential impact circle or class-location unit-based exception for Type C gathering lines larger than 16 inches in outside diameter. PHMSA considered alternatives raised in the GPAC discussions and public comments, such as having no limit to the potential impact circle exception or limiting it to an outside diameter of 24 inches. After considering these factors and the revised RIA, PHMSA ultimately determined that the 16-inch limit for the PIR exception initially presented to the committee was appropriate. PHMSA notes that API and other industry commenters on the NPRM suggested 16 inches or greater, without a PIR exception, as an alternative definition for Type C. Many of the Type C requirements applicable to larger pipelines relate to initial design, construction, and corrosion control issues, and it is important for such pipelines to be properly constructed, tested, coated, and have cathodic protection applied before new homes and other buildings intended for human occupancy are built nearby in the future—because such measures reduce associated safety risks. Additionally, the volume of a pipeline and the energy released during a rupture increase exponentially as pipe diameter increases. A rupture on a larger-diameter pipeline, all else being equal, is therefore more likely to have consequences other than direct damage to structures. These include externalized economic disruptions to downstream users and environmental consequences such as methane emissions and ecological damage. These external consequences can be significant even if the potential impact radius of a pipeline segment is smaller than the width of a gas transmission class location unit (660 ft.).

The NPRM's other proposed changes, including revisions to § 192.619(a)(4) and 192.619(e), only apply to gas transmission lines. In the Gas Transmission Final Rule, PHMSA clarified which new regulatory requirements from the NPRM apply only to gas transmission lines by including exceptions to those requirements for Type A and Type B gathering lines § 192.9(c). In this final rule, Type C lines are also exempt from these requirements. Several other regulatory changes proposed in the NPRM, specifically the proposed repair criteria, were intended to apply solely to gas transmission lines. PHMSA expects to clarify the applicability of those requirements when the final rule addressing the repair criteria for gas transmission lines is published under RIN 2137–AF39.

In response to comments and additional analysis, PHMSA has also updated the RIA. The revisions and clarifications described above reduce the cost of the requirements in § 192.9. Specifically, the most significant of the proposed requirements will now apply only to large-diameter pipelines and certain smaller-diameter pipelines that are located within a potential impact circle containing a building intended for human occupancy or other impacted sites. Additionally, 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.

IV. Section-by-Section Analysis

§ 191.1 Scope

Part 191 prescribes requirements for the reporting of incidents, safety-related conditions, annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of gas pipelines. Section 191.1 identifies the scope of applicability of the reporting requirements. PHMSA is revising § 191.1(a) to more clearly state that part 191 applies to offshore and onshore gas gathering not excepted by § 191.1(b). This change is intended to define the existing scope of part 191 to offshore gas gathering lines and the revised applicability to onshore gas gathering lines in plain language. PHMSA is revising § 191.1(b) to remove the exception to part 191 in § 191.1(b)(4) for unregulated, onshore gas gathering lines, including gathering lines that operate at less than 0 psig or are located within the inlets of the Gulf of Mexico. Incident Reports and Annual Reports will now be required for all onshore gas gathering lines, including Type R gathering lines. The expanded reporting requirements for previously unregulated gas gathering lines will provide data for monitoring the safety performance of these pipelines and a sound basis for evaluating if future regulatory changes are needed. However, this final rule excepts Type R gas gathering lines from requirements for OPID validation in § 191.22(b), notifications in § 191.22(c), and safety-related condition reports in § 191.23. Operators must still update their OPID information (*e.g.,* change in primary entity, change in name) before submitting an incident or annual report if a change has occurred.

§ 191.3 Definitions

PHMSA is adding definitions for ''regulated onshore gathering'' and ''reporting-regulated gathering.'' The term ''regulated onshore gathering'' is defined as a Type A, Type B, or Type C gas gathering line as determined in accordance with § 192.8. The term ''reporting-regulated gathering'' is defined as an onshore gathering pipeline other than a regulated onshore gathering pipeline. These pipelines have been designated as ''Type R'' gathering lines in § 192.8 but are not regulated under that part.

§ 191.15 Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities: Incident Report

This revision requires operators of Type R gathering pipelines to submit incident reports using DOT Form PHMSA F 7100.2–2. Regulated gathering lines, including Type C gathering lines, must continue to submit reports using DOT Form PHMSA F 7100.2.

For Type R gathering lines, an incident report is required for any event meeting the definition of an incident that occurs after the effective date of the rule. Operators are not required to categorize and report retroactively events which occurred before the effective date of the rule. The form excludes information related to part 192 requirements that do not apply.

§ 191.17 Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities: Annual Report

This section prescribes requirements for submitting annual reports. This final rule adds a paragraph (a)(2) that specifies the annual reporting requirements for operators of Type R gathering lines. Such operators must complete and submit DOT Form PHMSA F 7100.2–3. The first report is due no later than March 15, 2023 for the 2022 reporting year. The form instructions address how to report data attributes that are unknown.

§ 191.23 Reporting Safety-Related Conditions

This section specifies requirements for submitting safety-related conditions. In this final rule, paragraph (b)(1) is revised to except Type R gathering lines from safety-related condition reporting requirements in §§ 191.23 and 191.25.

§ 191.29 National Pipeline Mapping System

Section 191.29 specifies requirements for participation in the National Pipeline Mapping System (NPMS). Section 60132 of the Federal Pipeline Safety Law requires operators of a pipeline facilities excluding distribution and gathering lines to provide information to be included in the NPMS. In response to comments, the final rule clarifies that the requirements in § 191.29 do not apply to gas gathering lines. Although § 191.29(a) states the requirement applies only to operators of gas transmission lines and liquefied natural gas (LNG) facilities, the final rule makes the exclusion of gas gathering lines, including regulated onshore gas gathering lines, more explicit.

§ 192.3 Definitions

Section 192.3 defines certain terms used in part 192. The final rule adds a definition for ''composite materials.'' The term ''composite materials'' means the materials used to make pipes or components manufactured with a combination of either steel and/or plastic and a reinforcing material to maintain their circumferential or longitudinal strength. This definition is added to describe the process for notifying PHMSA prior to the use of composite materials on new, replaced, relocated, or otherwise changed Type C gathering lines in § 192.9. This definition alone does not authorize the use of composite pipe or materials under this part.

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

Section 192.8 describes how onshore pipelines and segments are determined to be onshore gathering lines and regulated onshore gathering lines. The definition of regulated onshore gathering line has been redesignated as paragraph (c). The final rule adds a new paragraph (b) to specify that gas gathering line must maintain records documenting the methodology used to determine the beginning and endpoints of segments determined to be gas gathering lines as determined in accordance with part 192. This final rule specifies that these records must be established within 1 year of the effective date of the rule, or within 1 year of pipeline installation, whichever is later. These records include the API RP 80 definitions and methods used to define the beginning and endpoints and where those points are located (*e.g.,* mile markers, address, or coordinates). Operators must maintain these records for the life of the pipeline, meaning until the pipeline is removed from the ground or permanently abandoned in place in accordance with § 192.727. An operator may request an alternative compliance deadline with a notification to PHMSA submitted in accordance with § 192.18 if the standard compliance deadline is impracticable. This notification must include a description of the affected facilities and operating environment, the justification for an alternative compliance deadline, and the operator's proposed alternative deadline. This notification must be submitted to PHMSA no later than 90 days prior to the standard compliance deadline in § 192.8(b)(1). The operator

may proceed with their proposed alternative deadline if they receive a no objection letter from PHMSA or if PHMSA has not replied within 90 days of submitting the notification.

The final rule also revises § 192.8(a)(5) to address the use of the incidental gathering concept described in API RP 80. For new, replaced, relocated, or otherwise changed gas gathering lines installed after the effective date of this final rule, the ''incidental gathering'' concept, as described in section 2.2.1.2.6 of API RP 80, may not be used if the ''incidental'' endpoint in paragraph 2.2(a)(1)(E) of API RP 80 is 10 miles or more from the furthermost downstream point where a gathering line end as determined in accordance with paragraphs 2.2 (a)(1)(A) through (a)(1)(D) of API RP 80 and § 192.8 (*e.g.* processing facilities, compressor stations, points of comingling). A new, replaced, relocated, or otherwise changed pipeline that is designated as an ''incidental gathering'' pipeline in API RP 80 but is 10 miles or more in length will be considered a transmission pipeline subject to all applicable portions of parts 191 and 192. Incidental gathering lines existing on or before the effective date of the rule may continue to operate as a gathering line, regardless of length.

One major aspect of this final rule is to identify a new category of regulated onshore gas gathering lines, designated as Type C lines in § 192.8. As discussed previously, a Type C regulated onshore gathering line is defined as any onshore gathering line that is 8.625 inches or larger in outside diameter, is located in a Class 1 location, and meets one of the following criteria, as applicable.

- Metallic pipe and the MAOP produces a hoop stress of 20 percent or more of SMYS;
- Metallic pipe and, if the stress level is unknown, the MAOP is more than 125 psig (862 kPa); or
- Non-metallic and the MAOP is more than 125 psig (862 kPa).

The minimum safety standards applicable to Type C gathering lines are specified in the revisions to § 192.9. The final rule adds the new Type C category to the table in § 192.8(b)(2). The purpose of adding this new category of regulated gas gathering lines is to ensure that operators of larger-diameter, higher-pressure gas gathering lines in Class 1 locations follow a basic set of requirements targeting known threats to public safety and pipeline integrity such as excavation damage, corrosion, and construction defects.

§ 192.9 What requirements apply to gathering lines?

This final rule codifies the minimum safety standards for Type C regulated gas gathering lines. The requirements for Type C gathering lines in this final rule are broken down as follows:

Type C requirements for pipelines with outside diameter of 8.625 inches and greater:

- Design, installation, construction, and initial inspection and testing per transmission line requirements in part 192 for lines that are new, replaced, relocated, or otherwise changed after the applicable compliance date in § 192.13;
- Corrosion control (part 192, subpart I);
- Damage prevention program (§ 192.614);
- Emergency plans (§ 192.615);
- Public awareness (§ 192.616);
- Line markers (§ 192.707); and
- Leakage surveys (§ 192.706).

Additional Type C requirements for pipelines with an outside diameter of 12.75 inches and greater:

- Applicable requirements of part 192 for plastic pipe and components; and
- Establish MAOP (§ 192.619).

The final rule adds § 192.9(f), which creates an exception from certain part 192 requirements if a Type C gathering line has a diameter of 16 inches or less and is not located near local communities as determined by one of the following methods:

Method 1. Potential Impact Circle. The segment is not located within a potential impact circle as defined in § 192.903 containing a building intended for human occupancy or other impacted site. This is the same method used to determine HCAs in the gas transmission integrity management regulations. Note that similar to the method for identifying HCAs, any point on a pipeline located *within* any potential impact circle containing a building intended for human occupancy or other impacted site may not apply the exception even if a potential impact circle drawn from that point does not contain such a location itself (Refer to Figure E.I.A. in appendix E to part 192).

The formula for calculating a potential impact radius is defined in § 192.903. PHMSA notes that this formula requires knowledge of the MAOP and nominal diameter of the pipeline. If the segment does not have an MAOP established in accordance with § 192.619, or if the diameter is unknown, the operator must use method 2 or not apply the exception and comply with the Type C requirements that are applicable based on the diameter of the pipeline. Additionally, operators must use a factor of 0.73 rather than the dry gas factor of 0.69 used in the integrity management regulations. The increased factor accounts for the potentially higher combustion energy of unprocessed natural gas, which may contain varying amounts of other combustible hydrocarbons.

Method 2: Class Location Unit. This analysis is similar to Method 1. However instead of calculating a potential impact circle, the class location unit as defined in § 192.5(a)(1) is used. This is the ''sliding mile'' or ''continuous-mile'' analysis used for class location determination. A class location unit is 1 mile in length and extends 220 yards on either side of the centerline of a pipeline. PHMSA notes that this uses the same ''sliding mile'' approach used for determining class location rather than static mile-long increments stacked end-over-end. The class-location unit moves along the pipeline, and if the sliding mile contains a building intended for human occupancy or other impacted site at any point during the mile's movement, then the exception in paragraph (f) does not apply for the entire mile of pipeline contained within the sliding mile. This method does not require knowledge of the pipeline's MAOP.

For the purposes of applying this exception, ''building intended for human occupancy'' or ''other impacted site'' is defined in § 192.9(f)(4) to mean any of the following:

- One or more buildings that may be occupied by humans, including homes, office buildings factories, outside recreation areas, and plant facilities.
- 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). This has the same meaning and interpretation as the Class 3 criterion in § 192.5(b)(3)(ii); or
- 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. This has the same meaning and interpretation of section (1)(ii) of the ''moderate consequence area'' definition in § 192.3.

The table below summarizes the applicability of the Type C requirements based on the size and location of a given segment.

Outside diameter	*Not* located near a building intended for human occupancy or other impacted site (§ 192.9(f))	Located near a building intended for human occupancy or other impacted site (§ 192.9(f))
Greater than or equal to 8.625 inches up to and including 12.75 inches.	—Design, Construction, Initial Testing (new/replaced/relocated/changed lines). —Damage Prevention. —Emergency plans.	—Design, Construction, Initial Testing (new/replaced/relocated/changed lines). —Corrosion Control. —Damage Prevention. —Emergency Plans. —Line Markers. —Public Awareness. —Leakage Surveys.
Greater than 12.75 inches up to and including 16 inches.	—Design, Construction, Initial Testing (new/replaced/relocated/changed lines). —Damage Prevention. —Emergency Plans.	All Type C Requirements.
Greater than 16 inches	All Type C Requirements	All Type C Requirements.

Section 60104(b) of the Pipeline Safety Acts exempts new design, installation, construction, initial inspection, and initial testing standards from applying to gathering lines that existed before the effective date of this final rule. In other words, if a previously unregulated gas gathering line becomes regulated by operation of this final rule (and is not itself replaced, relocated, or otherwise changed after the compliance date in § 192.13), the operator is not required to bring retroactively that pipeline facility into compliance with the new design, installation, construction, initial inspection, and initial testing requirements.

The rule also adds an exception in § 192.9(f)(3) to these requirements for segments shorter than 40 feet[78] that are installed, relocated, or changed on Type C gathering lines that were installed before the effective date of the rule. Regulations in part 192 that do not pertain to design, installation, construction, initial installation, or initial testing may apply to the segment regardless of the date of installation.

In § 192.9(g)(4), existing gathering lines that become classified as Type C regulated gathering lines due to the publication of this final rule have a 1-year compliance deadline to meet the applicable requirements in this section. An operator may request an alternative compliance deadline with a notification to PHMSA submitted in accordance with § 192.18 if the standard compliance deadline is impracticable. This notification must include a description of the affected facilities and operating environment and, for each requirement that requires an alternative compliance deadline: The justification for an alternative compliance deadline, and the operator's proposed alternative deadline. The notification must also include a description of actions the operator will take to ensure the safety of the affected facilities in the interim. This notification must be submitted no later than 90 days prior to the standard compliance deadline. The operator may proceed with their proposed alternative deadline if they receive a no objection letter from PHMSA or if PHMSA has not replied within 90 days of submitting the notification.

In § 192.9(g)(5), operators of gathering lines that become classified as Type C regulated gathering lines in the future due to an increase in MAOP, a change in dwelling density, or a change in class location have a 1-year compliance deadline to meet the requirements of this section. Similarly, an operator of a Type C gathering line that becomes subject to additional Type C requirements in the future, for example when a change in dwelling density or increased MAOP causes the exceptions in paragraph (f) to no longer apply, has a 1-year compliance deadline to meet those additional requirements. Conforming changes were made to paragraphs (g)(2) and (3) to clarify that the existing implementation deadlines now apply only to Type A and Type B regulated gathering lines.

The final rule also adds a new paragraph (h) to clarify that operators may install or replace pipe or components made of composite materials that are not otherwise authorized in part 192 on Type C gathering lines upon submittal of a notification to PHMSA pursuant to § 192.18, unless PHMSA issues an objection letter to the operator's notification. Under the § 192.18 notification process, PHMSA will evaluate the operator's proposed operation and maintenance procedures, which includes the operator's proposed remediation methods and procedures for identifying defects and determining the safe operating pressures of composite pipe when defects are found. PHMSA will not approve notifications that are not consistent with pipeline safety. A rejection under § 192.18 will not foreclose an operator's ability to seek a special permit in accordance with § 190.341.

Operators may continue to operate gathering lines containing composite pipe or materials existing on or before the effective date of the rule without notification to PHMSA. However, operators of Type C pipelines must comply with all other applicable Type C requirements once the final rule becomes effective. Additionally, per new § 192.9(e)(1)(i), notification is not required for replacements, relocations, or changes of composite pipe segments 40 feet or less in length on pipelines that were installed before the effective date of the rule. Replacements using composite materials on Type C gathering lines, including composite materials installed per a notification, require notification to PHMSA regardless of length. Replacing a segment of composite pipe with steel or plastic pipe and components authorized under part 192 does not require notification. The notification requirement does apply to repairs involving replacements, relocations, or significant changes to the pipe. If an operator discovers a condition that requires immediate replacement, operators should describe all urgent conditions in their notification to PHMSA, request an emergency special permit under § 190.341, or conduct the repair using materials authorized under part 192, such as steel.

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

This is a conforming change that repeats the compliance deadlines for Type C lines in § 192.8 and clarifies that the previously existing compliance deadlines for regulated gas gathering lines in that section continue to apply

[78] A single length of pipe is typically 40 feet in length.

to Type A and Type B regulated gathering lines.

§ 192.18 How To Notify PHMSA

This is a conforming change in the final rule to allow the use of the notification procedures in this section to comply with §§ 192.8(b) and (g)(4), 192.9(h), and 192.619(c)(2).

§ 192.150 Passage of Internal Inspection Devices

Currently, this section provides that Type A regulated gathering lines are exempt from the requirement that new gas transmission lines be able to accommodate the passage of instrumented internal inspection devices. This amendment clarifies that lower-risk Type B and Type C lines are also exempt.

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering lines?

This section of the final rule documents conforming changes to address the applicability of part 192, subpart I, to unregulated gathering lines that become Type C onshore regulated gathering lines. Specifically, it covers previously unregulated gathering lines that become regulated by operation of this final rule. Additionally, it covers previously unregulated gathering lines that become subject to Type C corrosion control requirements in the future due to a change in MAOP or the presence of a building intended for human occupancy or other impacted site. Such pipelines are treated as if they were installed before August 1, 1971, for the purposes of subpart I. The final rule also clarifies in paragraph (d) that gathering lines that are subject to subpart I at the time of construction must meet the corrosion control requirements applicable to pipelines installed after July 31, 1971.

§ 192.619 Maximum Allowable Operating Pressure: Steel or Plastic Pipelines

This section of the final rule includes conforming changes on the applicability of § 192.619 for determining the MAOP for newly regulated gathering lines, *i.e.,* Type C lines. Additionally, a new paragraph (c)(2) has been added to allow operators of newly regulated Type C gas gathering lines to establish an MAOP using ''other technology'', upon notification to PHMSA in accordance with § 192.18. This process would only be available to segments where the MAOP was established under § 192.619(c) and the operator does not have the requisite operational pressure records because the pipeline was previously unregulated and not required to retain such records. The justification of the proposed MAOP must be reviewed and accepted by a qualified technical subject matter expert. PHMSA expects a qualified subject matter expert to be an individual with formal or on-the-job technical training in the technical or operational area being analyzed, evaluated, or assessed. The operator must be able to document that the individual is appropriately knowledgeable and experienced in the subject being assessed.

V. Availability of Standards Incorporated by Reference

PHMSA currently incorporates by reference into 49 CFR parts 192, 193, and 195 all or parts of more than 80 standards and specifications developed and published by standard development organizations (SDO). In general, SDOs update and revise their published standards every 2 to 5 years to reflect modern technology and best technical practices. Sometimes multiple editions are published in a given year.

The National Technology Transfer and Advancement Act of 1995 (NTTAA, Pub. L. 104–113) directs Federal agencies to use standards developed by voluntary consensus standards bodies in lieu of government-written standards whenever possible. Voluntary consensus standards bodies develop, establish, or coordinate technical standards using agreed-upon procedures. In addition, OMB issued Circular A–119 to implement section 12(d) of the NTTAA relative to the utilization of consensus technical standards by Federal agencies.[79] This circular provides guidance for agencies participating in voluntary consensus standards bodies and describes procedures for satisfying the reporting requirements in the NTTAA.

Accordingly, PHMSA has the responsibility for determining, via petitions or otherwise, which currently referenced standards should be updated, revised, or removed, and which standards should be added to the Federal Pipeline Safety Regulations. Revisions to materials incorporated by reference in the Federal Pipeline Safety Regulations are handled via the rulemaking process, which allows for the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

Pursuant to 49 U.S.C. 60102(p), PHMSA may not issue amendments to the Federal Pipeline Safety Regulations that incorporate by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge. Further, the Office of the Federal Register issued a rulemaking on November 7, 2014, revising 1 CFR 51.5(b) to require that agencies detail in the preamble of a final rule how the materials being incorporated by reference are reasonably available to interested parties, and how interested parties can obtain those materials.[80]

The only standard incorporated by reference in the final rule is API RP 80. Free, online, read-only access to API RP 80 is available on the API website (*http://publications.api.org/AccessToDocuments.aspx;* navigate to the ''Exploration and Production'' category). Members of the public interested in obtaining API RP 80 can contact API using the contact information in this final rule's revisions to the regulatory text at § 192.7. In addition, PHMSA will provide individual members of the public temporary access to this or any other standard that is incorporated by reference in the Federal Pipeline Safety Regulations. Requests for access can be sent to the following email address: *phmsaphpstandards@dot.gov.*

VI. Regulatory Analysis and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the authority of Federal Pipeline Safety Law. Section 60101(b) authorizes the Secretary of Transportation to prescribe standards defining the term ''gathering line'' that account for the functional and operational characteristics of a pipeline. That section also authorizes the Secretary to prescribe standards defining the term ''regulated gathering line,'' which must consider factors such as location, length of line from the well site, operating pressure, throughput, and the composition of the transported gas. In addition, 49 U.S.C. 60102 authorizes the Secretary to issue regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. Further, 49 U.S.C. 60117(b)(2) authorizes the Secretary to require owners and operators of gathering lines to submit information pertinent to the Secretary's ability to make a determination as to whether and to what extent to regulate gathering lines. The

[79] 81 FR 4673 (Jan. 27, 2016).

[80] Incorporation by Reference, 79 FR 66278.

Secretary delegated his authority to the PHMSA Administrator under 49 CFR 1.97.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

Executive Order 12866 (''Regulatory Planning and Review'') [81] requires that agencies ''should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating.'' Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, Executive Order 12866 requires that ''agencies should select those [regulatory] approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach.'' Similarly, DOT Order 2100.6A (''Rulemaking and Guidance Procedures'') requires that regulations issued by PHMSA and other DOT Operating Administrations should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts.

Executive Order 12866 and DOT Order 2100.6A require that PHMSA submit ''significant regulatory actions'' to the Office of Management and Budget (OMB) for review. This final rule has been determined to be significant under section 3(f) of Executive Order 12866 and was reviewed by OMB. It is also considered significant under DOT Order 2100.6. The Office of Information and Regulatory Affairs (OIRA) has not designated this rule as a ''major rule'' as defined by the Congressional Review Act (5 U.S.C. 801 *et seq.*).

Executive Order 12866 and DOT Order 2100.6A also require PHMSA to provide a meaningful opportunity for public participation, which reinforces requirements for notice and comment in the Administrative Procedure Act (APA, 5 U.S.C. 551 *et seq.*). In accord with the requirement, PHMSA 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.

PHMSA expects benefits of the final rule to consist of improved safety and avoided environmental harms (including greenhouse gas emissions) from reduction of risk of failures of onshore natural gas gathering lines due to improved leak detections and subsequent repairs. The expected benefits will depend on the degree to which compliance actions result in additional safety measures, relative to the baseline, and the effectiveness of these measures in preventing or mitigating future pipeline failures. PHMSA estimates annualized costs of $13.7 million per year using a 7 percent discount rate. The costs for compliance with annual reporting and, for Type C gathering lines, compliance with part 192 are expected to be higher in the initial compliance period, as operators will incur one-time costs to achieve compliance in the years leading up to the compliance deadline. Thereafter recurring costs are expected to be lower. For more information, please see the RIA posted in the rulemaking docket.

C. Environmental Justice

DOT Order 5610.2C and Executive Orders 12898 (''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations''),[82] 13985 (''Advancing Racial Equity and Support for Underserved Communities Through the Federal Government''),[83] 13990 (''Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis''),[84] and 14008 (''Tackling the Climate Crisis at Home and Abroad'') [85] require DOT agencies to achieve environmental justice as part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects, including interrelated social and economic effects, of their programs, policies, and activities on minority populations, low-income populations, and other disadvantaged communities.

PHMSA has evaluated this final rule under DOT Order 5610.2C and the Executive orders listed above and has determined it would not cause disproportionately high and adverse human health and environmental effects on minority populations, low-income populations, or other underserved and disadvantaged communities. The rulemaking is facially neutral and national in scope; it is neither directed toward a particular population, region, or community, nor is it expected to adversely impact any particular population, region, or community. And insofar as PHMSA expects the rulemaking would reduce the safety and environmental risks associated with onshore natural gas gathering lines, many of which are located in the vicinity of environmental justice communities,[86] PHMSA does not expect the regulatory amendments introduced by this final rule would entail disproportionately high adverse risks for minority populations, low-income populations, or other underserved and other disadvantaged communities in the vicinity of those pipelines. Lastly, as explained in final environmental assessment (EA), PHMSA expects that the regulatory amendments in this final rule will yield greenhouse gas emissions reductions, thereby reducing the risks posed by anthropogenic climate change to minority, low-income, underserved, and other disadvantaged populations and communities.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA, 5 U.S.C. 601 *et seq.*) requires Federal regulatory agencies to prepare a Final Regulatory Flexibility Analysis (FRFA) for any final rule subject to notice-and-comment rulemaking under the APA unless the agency head certifies that the rule will not have a significant economic impact on a substantial number of small entities. This final rule was developed in accordance with Executive Order 13272 (''Proper Consideration of Small Entities in Agency Rulemaking'') [87] to promote compliance with the RFA and to ensure that the potential impacts of the rulemaking on small entities has been properly considered.

PHMSA does not have access to firm-level data on gathering line operators that are not currently regulated under part 191 or 192. However, based on data on regulated gathering line operators produced by Dun and Bradstreet, approximately 40 percent of currently regulated gathering line operators are identified as small entities, and those entities operate approximately 24 percent of onshore regulated gas gathering line mileage. Therefore, a

[81] 58 FR 51375 (Oct. 4, 1993).

[82] 59 FR 7629 (Feb. 16, 1994).

[83] 86 FR 7009 (Jan. 20, 2021).

[84] 86 FR 7037 (Jan. 20, 2021).

[85] 86 FR 7619 (Feb. 1, 2021).

[86] *See* Ryan Emmanuel, et al., ''Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,'' 5:6 GeoHealth (June 2021), *https://agupubs.onlinelibrary.wiley.com/toc/24711403/2021/5/6* (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

[87] 67 FR 53461 (Aug. 16, 2002).

significant share of affected entities can be classified as small entities. However, PHMSA expects the magnitude of the economic impact on those entities to 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 (NAICS code 486110), illustrating the minor financial impact on firms operating within this space. PHMSA has prepared a FRFA, available in the docket for the rulemaking, in which PHMSA certifies that the rule will not have a significant impact on a substantial number of small entities.

E. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this final rule in accordance with the principles and criteria in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments'') [88] and DOT Order 5301.1 (''Department of Transportation Programs, Polices, and Procedures Affecting American Indians, Alaska Natives, and Tribes''). Executive Order 13175 requires agencies to assure meaningful and timely input from Tribal government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities or the relationship and distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the rulemaking and determined that it would not significantly or uniquely affect Tribal communities or Indian Tribal governments. The rulemaking's regulatory amendments are facially neutral and would have broad, national scope; PHMSA, therefore, does not expect this rulemaking to significantly or uniquely affect Tribal communities, much less impose substantial compliance costs on Native American Tribal governments or mandate Tribal action. And insofar as PHMSA expects the rulemaking will improve natural gas gathering line safety and reduce environmental risks, PHMSA does not expect it would entail disproportionately high adverse risks for Tribal communities. PHMSA also received no comments alleging ''substantial direct compliance costs'' or ''substantial direct effects'' on Tribal communities and Governments. For these reasons, PHMSA has determined the funding and consultation requirements of Executive Order 13175 and DOT Order 5301.1 do not apply.

F. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. PHMSA expects this final rule to impact the information collections described below.

PHMSA will submit an information collection revision request to OMB for approval based on the requirements in this final rule. The information collections are contained in the pipeline safety regulations, 49 CFR parts 190 through 199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burdens for the following information collections are estimated to be revised as follows:

1. *Title:* Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 01/31/2023.

Abstract: A person owning or operating a natural gas pipeline facility is required to maintain records, make reports, and provide information to the Secretary of Transportation at the Secretary's request. This mandatory information collection request would require owners and/or operators of gas pipeline systems to make and maintain records in accordance with the requirements prescribed in 49 CFR part 192 and to provide information to the Secretary of Transportation at the Secretary's request. Certain records are maintained for a specific length of time while others are required to be maintained for the life of the pipeline. PHMSA uses these records to verify compliance with regulated safety standards and to inform the agency on possible safety risks.

Based on the provisions in the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, PHMSA estimates that 370 new Type C gas gathering pipeline operators ~ (91,000 Type C miles w/o prior regulation) will be subject to these requirements. PHMSA estimates that it will take these 370 operators 6 hours to create and maintain records associated with 49 CFR 192.9 requirements. Therefore, PHMSA expects to add 370 responses and 2,220 hours to this information collection as a result of the provisions in this final rule.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,861,842.

Total Annual Burden Hours: 1,677,030.

Frequency of Collection: On occasion.

2. *Title:* Annual and Incident Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 10/31/2024.

Abstract: This mandatory information collection covers the collection of annual and immediate notice of incident report data from Gas pipeline operators. As a result of the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, all gas gathering operators will become subject to incident and annual reporting requirements. PHMSA is revising this information collection to account for the new addition to the reporting community. PHMSA will require 500 currently unregulated gas gathering line operators (370 Type C operators and 130 Type R operators) to complete and submit annual reports each year. Type C operators will submit annual report data on DOT Form PHMS F7 100.2–1. The estimated burden for submitting this form is 47 hours per report. Type R operators will submit annual report data on the new DOT Form PHMSA F7 100.2–3. The estimated burden for submitting this form is 21 hours per report. These changes will result in an overall annual burden increase of 20,120 hours (17,390 hours annually for Type C operators and 2,730 hours annually for Type R operators) for this information collection.

Gas Gathering operators will also be required to make immediate telephonic notification of incidents, should they occur. PHMSA expects that these previously unregulated operators will make approximately 85 telephonic notifications of incidents per year. PHMSA estimates that it takes 30 minutes to complete a telephonic notification. As such, the estimated burden for gas gathering operators to make immediate notification of incidents is approximately 43 hours.

As a result of the provisions mentioned above, the burden for this information collection will increase by 585 new responses and 10,543 burden hours.

Affected Public: Natural Gas Pipeline Operators.

[88] 65 FR 67249 (Nov. 6, 2000).

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 2,832.

Total Annual Burden Hours: 91,964.

Frequency of Collection: Annually and on occasion.

3. *Title:* Incident Reports for Natural Gas Pipeline Operators.

OMB Control Number: 2137–0635.

Current Expiration Date: 10/31/2024.

Abstract: Operators of natural gas pipelines and LNG facilities are required to report incidents, on occasion, to PHMSA per the requirements in 49 CFR part 191. This mandatory information collection covers the collection of incident report data from natural gas pipeline operators. The reports contained within this information collection support the Department of Transportation's strategic goal of safety. This information is an essential part of PHMSA's overall effort to minimize natural gas transmission, gathering, and distribution pipeline failures. Due to the provisions contained within the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, operators will be required to submit reports of incidents that occur on previously unregulated gas gathering systems.

Based on PHMSA's estimate of the mileage of Type C and Type R gas gathering pipelines and the incident rate on Type A and Type B gas gathering pipelines, PHMSA expects to receive approximately 85 incident reports (18 Type C incident reports and 67 Type R incident reports) each year from gas gathering operators. As a result, the burden for this information collection will increase by 85 responses. The burden per incident report is estimated at 12 hours per report. This results in an estimated burden increase of 1,020 hours (216 hours for Type C and 804 hours for Type R) per year.

Affected Public: Natural Gas Pipeline Operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 344.

Total Annual Burden Hours: 4,128.

Frequency of Collection: On occasion.

4. *Title:* National Registry of Pipeline and LNG Operators.

OMB Control Number: 2137–0627.

Current Expiration Date: 01/31/2023.

Abstract: The National Registry of Pipeline and LNG Operators serves as the storehouse for the reporting requirements for an operator regulated or subject to reporting requirements under 49 CFR part 192, 193, or 195. This mandatory information collection would require jurisdictional pipeline operators to submit the required data to register with the National Registry of Pipeline and LNG Operators and notify PHMSA when they experience significant asset changes, including new construction, that affect PHMSA's ability to accurately monitor and assess pipeline safety performance. Certain types of changes to, or within, an operator's facilities or pipeline network represent potential safety-altering activities for which PHMSA may need to inspect, investigate, or otherwise oversee to ensure that any public safety concerns are adequately and proactively addressed. The forms for assigning and maintaining Operator Identification (OPID) information are the Operator Assignment Request Form (PHMSA F 1000.1) and Operator Registry Notification Form (PHMSA F 1000.2). The purpose of this information collection is to maintain an accurate assessment of the Nation's pipeline infrastructure and to be kept abreast of conditions that could potentially compromise the safety and economic viability of the U.S. pipeline system.

Due to the provisions contained within the Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments final rule, gas gathering pipeline operators must now request OPIDs due to the repeal of the reporting exception for gathering pipelines other than regulated gathering lines as determined in § 192.8. PHMSA plans to revise the OPID Registry form and instructions to account for this addition to the reporting community. PHMSA believes that many operators of previously unregulated gathering lines are already submitting annual report data for regulated gas gathering lines and may already have an OPID. As such, PHMSA expects to receive approximately 13 new OPID requests. PHMSA also requires these newly regulated operators to submit notifications to PHMSA in certain instances. PHMSA similarly expects to receive approximately 13 new notifications from gas gathering pipeline operators. These additions will result in an increase to the burden of this information collection by 26 responses and 26 burden hours.

Affected Public: Operators of Natural Gas, Hazardous Liquid, and Liquefied Natural Gas pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 744.

Total Annual Burden Hours: 744.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill or Cameron Satterthwaite, Office of Pipeline Safety (PHP–30), Pipeline Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, Telephone (202) 366–1246.

G. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (UMRA, 2 U.S.C. 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate of $100 million or more (in 1996 dollars) in any given year, the agency must prepare, amongst other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate. PHMSA prepared a final RIA and determined that this final rule does not impose enforceable duties on State, local, or Tribal governments or on the private sector of $100 million or more (in 1996 dollars) in any one year. A copy of the RIA is available for review in the docket of this rulemaking.

H. National Environmental Policy Act

The National Environmental Policy Act of 1969 (NEPA, 42 U.S.C. 4321 *et seq.*) requires Federal agencies to consider the consequences of major Federal actions and prepare a detailed statement on actions significantly affecting the quality of the human environment. The Council on Environmental Quality implementing regulations (40 CFR parts 1500–1508) require Federal agencies to conduct an environmental review considering (1) the need for the action, (2) alternatives to the action, (3) probable environmental impacts of the action and alternatives, and (4) the agencies and persons consulted during the consideration process. DOT Order 5610.1C (''Procedures for Considering Environmental Impacts'') establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

PHMSA has completed its NEPA analysis. Based on the environmental assessment, PHMSA determined that an environmental impact statement is not required for this rulemaking because it will not have a significant impact on the human environment. The final EA and Finding of No Significant Impact have been placed into the docket addressing the comments received.

I. Executive Order 13132: Federalism

PHMSA analyzed this final rule in accordance with Executive Order 13132 (''Federalism'').[89] Executive Order 13132 requires agencies to assure meaningful and timely input by State and local officials in the development of regulatory policies that may have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have a substantial direct effect on State and local governments, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government. This rulemaking action does not impose substantial direct compliance costs on State and local governments. The final rule exercises PHMSA's existing authority to require operators of gas gathering line to submit safety data (49 U.S.C. 60117(b)(2)) and to define and establish safety standards for regulated gas gathering lines (49 U.S.C. 60101(b)). PHMSA determined the final rule's changes to the requirements for onshore gas gathering lines were necessary based on the results of PHMSA's review of existing gas gathering requirements performed pursuant to section 21 of the 2011 Pipeline Safety Act.

Section 60104(c) of Federal Pipeline Safety Law prohibits certain State safety regulation of interstate pipelines. Under the pipeline safety laws, States that have submitted a current certification under section 60105(a) can augment Federal pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate.

In this instance, the preemptive effect of the final rule is limited to the minimum level necessary to achieve the objectives of the Federal Pipeline Safety Law under which the final rule is promulgated. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

J. Executive Order 13211: Significant Energy Actions

Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'') [90] requires Federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' Executive Order 13211 defines a ''significant energy action'' as any action by an agency (normally published in the **Federal Register**) that promulgates, or is expected to lead to the promulgation of, a final rule or regulation that (1)(i) is a significant regulatory action under Executive Order 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy (including a shortfall in supply, price increases, and increased use of foreign supplies); or (2) is designated by the Administrator of the OIRA as a significant energy action.

This final rule is a significant action under Executive Order 12866; however, it is expected to have an annual effect on the economy of less than $100 million. Further, this final rule is not likely to have a significant adverse effect on supply, distribution, or energy use, as further discussed in the RIA. Further, OIRA has not designated this final rule as a significant energy action.

K. Privacy Act Statement

In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to better inform its rulemaking process. DOT posts these comments, without edit, including any personal information the commenter provides, to *www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *www.dot.gov/privacy.*

L. Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. The RIN number contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

M. Executive Order 13609 and International Trade Analysis

Executive Order 13609 (''Promoting International Regulatory Cooperation'') [91] requires agencies to consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96–39), as amended by the Uruguay Round Agreements Act (Pub. L. 103–465), prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards, so long as the standards have a legitimate domestic objective, such as providing for safety, and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards.

PHMSA participates in the establishment of international standards to protect the safety of the American public. PHMSA has assessed the effects of the rulemaking and determined that it will not cause unnecessary obstacles to foreign trade.

List of Subjects

49 CFR Part 191

MAOP exceedance, Pipeline reporting requirements.

49 CFR Part 192

Incorporation by reference, Integrity assessments, MAOP reconfirmation, Material verification, Pipeline safety, Predicted failure pressure, Reporting and recordkeeping requirements, Risk assessment, Safety devices.

In consideration of the foregoing, PHMSA amends 49 CFR parts 191 and 192 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for part 191 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et seq.,* and 49 CFR 1.97.

■ 2. The heading for part 191 is revised to read as set forth above.

■ 3. In § 191.1, paragraphs (a) and (b)(2) and (3) are revised, paragraph (b)(4) is removed, and paragraph (c) is added to read as follows:

[89] 64 FR 43255 (Aug. 10, 1999).

[90] 66 FR 28355 (May 22, 2001).

[91] 77 FR 26413 (May 4, 2012).

§ 191.1 Scope.

(a) This part prescribes requirements for the reporting of incidents, safety-related conditions, annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of underground natural gas storage facilities and natural gas pipeline facilities located in the United States or Puerto Rico, including underground natural gas storage facilities and pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331). This part applies to offshore gathering lines (except as provided in paragraph (b) of this section) and to onshore gathering lines, including Type R gathering lines as determined in § 192.8 of this chapter.

(b) * * *

(2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9; or

(3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator.

(c) Sections 191.22(b) and (c) and 191.23 do not apply to the onshore gathering of gas—

(1) Through a pipeline that operates at less than 0 psig (0 kPa);

(2) Through a pipeline that is not a regulated onshore gathering pipeline; or

(3) Within inlets of the Gulf of Mexico, except for the requirements in § 192.612 of this chapter.

■ 4. In § 191.3, add definitions for ''Regulated onshore gathering'' and ''Reporting-regulated gathering'' in alphabetical order to read as follows:

§ 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.

Reporting-regulated gathering means a Type R gathering line as determined in § 192.8 of this chapter. A Type R gathering line is subject only to this part.

* * * * *

■ 5. In § 191.15, paragraph (a) is revised to read as follows:

§ 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 system must submit Department of Transportation (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.

(2) *Reporting-regulated gathering.* Each operator of a reporting-regulated gathering pipeline system 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 that occurs after May 16, 2022.

* * * * *

■ 6. In § 191.17, paragraph (a) is revised to read as follows:

§ 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 must submit an annual report for that system on DOT Form PHMSA F 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 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.

* * * * *

■ 7. In § 191.23, revise paragraph (b)(1) to read as follows:

§ 191.23 Reporting safety-related conditions.

* * * * *

(b) * * *

(1) Exists on a master meter system, a reporting-regulated gathering pipeline, or a customer-owned service line;

* * * * *

■ 8. In § 191.29, paragraph (c) is added to read as follows:

§ 191.29 National Pipeline Mapping System.

* * * * *

(c) This section does not apply to gathering pipelines.

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

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

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

■ 10. In § 192.3, add a definition for ''Composite materials'' in alphabetical order to read as follows:

§ 192.3 Definitions.

* * * * *

Composite materials means materials used to make pipe or components manufactured with a combination of either steel and/or plastic and with a reinforcing material to maintain its circumferential or longitudinal strength.

* * * * *

■ 11. Amend § 192.8 as follows:
■ a. Revise the section heading;
■ b. Add paragraph (a)(5);
■ c. Redesignate paragraph (b) as a paragraph (c);
■ d. Add new paragraph (b); and
■ e. Revise newly redesignated paragraph (c).

The revisions and addition read as follows:

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

(a) * * *

(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 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 an ''incidental gathering'' pipeline is 10 miles or more in length, the entire portion of the 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 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) of this section, by:

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

(2) An alternative deadline approved by the Pipeline and Hazardous Materials Safety Administration (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; and

(iii) Proposed alternative deadline.

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

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

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

TABLE 1 TO PARAGRAPH (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; or (c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.	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 pipeline 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 SMYS; —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).	Class 1 location	None.
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.

■ 12. Amend § 192.9 as follows:

■ a. Revise the section heading;

■ b. Redesignate paragraph (e) as paragraph (g);

■ c. Add a new paragraph (e) and paragraph (f);

■ d. Revise newly redesignated paragraphs (g)(2) and (3);

■ e. Add paragraphs (g)(4) and (5); and

■ f. Add paragraph (h).

The revisions and additions read as follows:

§ 192.9 What requirements apply to gathering pipelines?

* * * * *

(e) *Type C lines.* 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, 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 J of this part applicable to transmission lines. 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;

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

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

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

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

(vii) 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).

(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) 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) 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) *Exceptions.* (1) Compliance with paragraphs (e)(1)(ii), (v), (vi), and (vii) and (e)(2)(i) and (ii) of this section is not required for pipeline segments that are 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.

(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) 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.;

(ii) 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

(iii) 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.

(g) * * *

(2) If a Type A or Type B regulated onshore gathering pipeline existing on April 14, 2006, was not previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the pipeline listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:

Requirement	Compliance deadline
(i) Control corrosion according to requirements for transmission lines in subpart I of this part	April 15, 2009.
(ii) Carry out a damage prevention program under § 192.614	October 15, 2007.
(iii) Establish MAOP under § 192.619	October 15, 2007.
(iv) Install and maintain line markers under § 192.707	April 15, 2008.
(v) Establish a public education program under § 192.616	April 15, 2008.
(vi) Other provisions of this part as required by paragraph (c) of this section for Type A lines	April 15, 2009.

(3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering pipeline to become a Type A or Type B regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the pipeline becomes a regulated onshore gathering pipeline to comply with this section.

(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, except for paragraph (h) of this section, on or before:

(i) May 16, 2023; or

(ii) 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* paragraph (f) of this section), the operator has 1 year after the pipeline becomes subject to the additional requirements to comply with this section.

(h) *Composite materials.* Pipe and components made with composite materials not otherwise authorized for use under this part may be used on Type C gathering pipelines if the following requirements are met:

(1) 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.

(2) Operators must notify 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 in a Type C gathering pipeline. The notifications required by this section must include a detailed description of the pipeline facilities in which pipe or components made of composite materials would be used, including:

(i) 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;

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

(iii) 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;

(iv) 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;

(v) 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;

(vi) 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;

(vii) 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;

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

(ix) 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.

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

■ 13. In § 192.13, paragraphs (a) and (b) are revised to read as follows:

§ 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) The compliance deadlines are as follows:

Pipeline	Date
(i) Offshore gathering pipeline.	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 to which this part did not apply until May 16, 2022.	May 16, 2023.
(iv) All other pipelines	March 12, 1971.

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

Pipeline	Date
(1) Offshore gathering pipeline.	July 31, 1977.
(2) Regulated onshore gathering pipeline to which this part did not apply until April 14, 2006.	March 15, 2007.
(3) Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022.	May 16, 2023.
(4) All other pipelines	November 12, 1970.

* * * * *

■ 14. In § 192.18, paragraph (c) is revised to read as follows:

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if the notification is made pursuant to § 192.8(b)(2), § 192.9(g)(4)(ii) and (h), § 192.461(g), § 192.506(b), § 192.607(e)(4) and (5), § 192.619(c)(2), § 192.624(c)(2)(iii) and (c)(6), § 192.632(b)(3), § 192.710(c)(7), § 192.712(d)(3)(iv) and (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.

■ 15. Amend § 192.150 as follows:

■ a. In paragraph (b)(7)(ii), remove the word ''and'';

■ b. Redesignate paragraph (b)(8) as paragraph (b)(9); and

■ c. Add a new paragraph (b)(8).

The addition reads as follows:

§ 192.150 Passage of internal inspection devices.

* * * * *

(b) * * *

(8) Gathering lines; and

* * * * *

■ 16. In § 192.452, revise the section heading and paragraph (b) introductory text and add paragraphs (c) and (d) to read as follows:

§ 192.452 How does this subpart apply to converted pipelines and regulated onshore gathering pipelines?

* * * * *

(b) *Type A and B onshore gathering lines.* For any Type A or Type B regulated onshore gathering line under § 192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under § 192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

* * * * *

(c) *Type C onshore regulated gathering lines.* For any Type C onshore regulated gathering pipeline under § 192.9 existing on May 16, 2022, that was not previously subject to this part, and for any Type C onshore gas gathering pipeline that becomes subject to this subpart after May 16, 2022, because of an increase in MAOP, change in class location, or presence of a building intended for human occupancy or other impacted site:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

(d) *Regulated onshore gathering lines generally.* Any gathering line that is subject to this subpart per § 192.9 at the time of construction must meet the requirements of this subpart applicable to pipelines installed after July 31, 1971.

■ 17. In § 192.619, revise paragraph (a)(3) and paragraph (c) to read as follows:

§ 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 regulated gathering pipeline (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 pipeline 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)) that first became subject to this part (other than § 192.612) on or after May 16, 2022.	May 16, 2023, *or date pipeline becomes subject to this part, whichever is later*.	5 years preceding applicable date in second column.
(iii) 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 applicable date in second column.
(iv) Offshore gathering pipelines	July 1, 1976	July 1, 1971.
(v) All other pipelines	July 1, 1970	July 1, 1965.

* * * * *

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

(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 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.

* * * * *

Issued in Washington, DC on November 2, 2021, under authority delegated in 49 CFR 1.97.

Tristan H. Brown,

Acting Administrator.

[FR Doc. 2021–24240 Filed 11–12–21; 8:45 am]

BILLING CODE 4910–60–P

EXHIBIT 2

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,

Matthew Hite
Vice President of Government Affairs
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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

Table of Contents

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

[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

[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).

[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

[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]

[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

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

[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

[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]

[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

[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

[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]

[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

[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.

[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

[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

[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

[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.

[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.

[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.

EXHIBIT 3

U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, DC 20590

April 1, 2022

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Re: Response to 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" (2137-AF38)

Dear Messrs. Hite and Murk:

This is in response to the December 15, 2021 (1) Petition for Reconsideration (the "Petition") of the final rule titled "Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments"[1] (the "Final Rule"), and (2) Motion to Stay [the] Final Rule (the "Motion") you filed on behalf of the GPA Midstream Association ("GPA") and the American Petroleum Institute ("API") (collectively, "Petitioners").[2]

[1] 86 FR 63266 (Nov. 15, 2021).
[2] The Motion requests a stay of certain provisions of the Final Rule. See Motion at 1. PHMSA also acknowledges that the Pennsylvania Independent Oil & Gas Association (Letter in Support, Doc. No. PHMSA-2011-0023-0496 (Dec. 28, 2021)) and the Marcellus Shale Coalition (Letter in Support, Doc. No. PHMSA-2011-0023-0494 (Dec. 20, 2021)) support the Petition and Motion. PHMSA also acknowledges Petitioners' February 24, 2022 Request for Action on Petition for Reconsideration and Motion to Stay Final Rule (which the Ohio Oil and Gas Association, the Pennsylvania Independent Oil & Gas Association, and the Marcellus Shale Coalition joined) calling on PHMSA to respond to the Petition and Motion promptly. PHMSA also notes that other stakeholders — in particular, the

The Petition contends that the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") adoption of the Final Rule failed to comply with procedural requirements under the Pipeline Safety Act, as amended, (49 U.S.C. 60101 et seq.) and the Administrative Procedure Act (5 U.S.C. 551 et seq., the "APA") by failing to adequately evaluate the costs and benefits of the Final Rule and by failing to respond to Petitioners' comments regarding the costs and benefits of the Final Rule. The Petition also suggests that PHMSA failed to conduct an adequate assessment the impact of the Final Rule on small entities under the Regulatory Flexibility Act (5 U.S.C. 601 et seq., the "RFA"). In addition, the Petition requests that PHMSA adopt revisions to certain provisions of the Final Rule. The Motion seeks a stay of certain provisions of the Final Rule, asserting that Petitioners' members will suffer irreparable harm unless PHMSA grants a stay of certain elements of the Final Rule pertaining to Type C gathering lines pending resolution of the Petition.

As explained below and in the enclosed Appendix, the Petitioners' assertions regarding PHMSA's development process and cost-benefit analyses supporting the Final Rule are belied by the administrative record and not supported by the information that the Petitioners submitted regarding the potential costs of the 2016 Notice of Proposed Rulemaking.[3] Further, the Petitioners' assertion of procedural deficiencies under the Pipeline Safety Act requirements regarding the role of the Gas Pipeline Advisory Committee (GPAC) are inconsistent with evidence in the administrative record, inconsistent with longstanding practice, and unsupported by statutory text and legislative history. For these reasons, and as explained in more detail below, PHMSA denies the Petition. PHMSA also declines to adopt the Petitioners' proposed revisions to the Final Rule as those proposed changes are inconsistent with PHMSA's statutory obligations to protect public safety and the environment. Lastly, PHMSA denies the Motion because Petitioners have failed to demonstrate that a stay of any provision of the Final Rule is warranted.

PHMSA acknowledges that Petitioners raise concerns regarding certain language in the Final Rule that would benefit from clarification. With that in mind, PHMSA will, in parallel with issuing this response letter, issue a Federal Register notice that will:

- Consistent with statements in the preamble to the Final Rule, codify in regulation that Type C gas gathering lines that are not otherwise required to establish a maximum allowable operating pressure (''MAOP'') under 49 CFR 192.9(e)(2)(ii) and 192.619 do not have to submit safety related condition reports pursuant to § 191.23;
- Memorialize a limited enforcement discretion assuring operators of certain Type C gathering lines (those existing on May 16, 2022 which are subsequently replaced, relocated, or otherwise changed), that PHMSA will not enforce against such replacement, relocation, or change projects the 10-mile threshold within the Final Rule's revised definition of "incidental gathering" at § 192.8(a)(5); and

Pipeline Safety Trust and the Environmental Defense Fund — met with PHMSA to express their positions on the Petition and Motions, and the latter has also filed to the docket a letter in opposition to the Petition. Environmental Defense Fund, Opposition of Environmental Defense Fund to GPA Midstream and API's Petition for Reconsideration and Motion for Stay, Doc. Nos. PHMSA-2011-0023-0501, 0502, and 0503 (Mar. 30, 2022).

[3] "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines," 81 FR 20722 (Apr. 8, 2016) ("NPRM").

- Clarify in explanatory text that operators may use the default yield strength specified at § 192.107(b)(2) in calculating specified minimum yield strength ("SMYS") in connection with determining whether a gathering line is a Type C line pursuant to § 192.8(c)(2).

PHMSA discusses the above clarifications in section II below.

I. PHMSA'S EVALUATION OF THE COSTS AND BENEFITS OF THE FINAL RULE WAS ENTIRELY CONSISTENT WITH ITS OBLIGATIONS UNDER THE PIPELINE SAFETY ACT, THE APA, AND THE RFA.

The regulatory amendments adopted in the Final Rule are consistent with the reasoned decision-making required by the APA and the Pipeline Safety Act. PHMSA's development of the Final Rule spanned the better part of a decade and afforded extensive opportunities — including a 2011 Advanced Notice of Proposed Rulemaking, a 2016 NPRM, and a June 2019 GPAC meeting[4] — for stakeholder input on the costs and benefits of the rulemaking. Petitioners acknowledge they were active participants in those proceedings: before issuance of the Final Rule they had submitted *more than 550 pages* of documents[5] in the regulatory docket, attended and spoke during the 2019 GPAC Meeting, and attended multiple meetings with PHMSA and the Office of Management and Budget (OMB) on the rulemaking.[6]

That extensive administrative record is hard to square with Petitioners' contention that PHMSA's rulemaking reflected inadequate process or that PHMSA or the GPAC ignored their concerns regarding the costs and benefits of the rulemaking. Rather, the record illustrates precisely the opposite: between the NPRM and the Final Rule, PHMSA adopted changes to the scope of the rulemaking's substantive requirements and its supporting cost-benefit methodology in response to concerns raised by the Petitioners and other stakeholders regarding the costs and benefits of the rulemaking.[7] The administrative record similarly contains ample evidence that PHMSA's promulgation of the Final Rule is consistent with the requirements governing evaluation of costs and benefits under the APA, the Pipeline Safety Act, and the RFA.

[4] "Pipeline Safety: Safety of Gas Transmission Pipelines," 76 FR 53086 (Aug. 25, 2011) ("ANPRM"); Gas Pipeline Advisory Committee Public Meeting to Discuss 'Safety of Gas Gathering Pipelines,' RIN 2137-AF38 (June 25-26, 2019), https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=143 ("GPAC Meeting").

[5] This value excludes an additional 50+ pages of Petitioners' submissions after publication of the Final Rule.

[6] Summary of Meeting: Regarding Regulation of Safety of Gas Gathering Pipelines, Doc. No. PHMSA-2011-0023-0473 (Mar. 29, 2019) (meeting between GPA Midstream and PHMSA representatives); Meeting Summary: 1030-1130 Jan. 6, 2021 Meeting with GPA Midstream Association Re Gas Gathering Rulemaking, Doc. No. PHMSA-2011-0023-0480 (Jan. 6, 2021) (meeting between GPA Midstream and PHMSA representatives recording that GPA Midstream called on PHMSA to issue the Final Rule promptly); EO12866 Meeting Summary: PHMSA Office of Pipeline Safety – Safety of Gas Gathering Pipelines, Doc. No. PHMSA-2011-0023-0482 (Oct. 4, 2021) (meeting between API, PHMSA, DOT, and OMB); EO12866 Meeting Summary: PHMSA Office of Pipeline Safety – Safety of Gas Gathering Pipelines, Doc. No. PHMSA-2011-0023-0483 (Oct. 5, 2021) (meeting between GPA Midstream, PHMSA, DOT, and OMB).

[7] GPA Midstream acknowledged and praised a number of those substantive changes during the GPAC Meeting. See Transcript, "GPAC Meeting," at 84:19-86:14 (statement of Matthew Hite "applaud[ing] PHMSA for withdrawing or modifying the most controversial aspects of the original rulemaking proposal . . . . ").

A. The Extensive Administrative Record Evinces PHMSA's Careful Evaluation of Final Rule's Costs and Benefits.

The administrative record demonstrates that PHMSA thoroughly evaluated the costs and benefits of the rulemaking consistent with its obligations under the Pipeline Safety Act, the APA, and the RFA. Each of the NPRM, Final Rule, and the supporting documents thereto[8] describe the safety and environmental benefits of aligning regulation of gas gathering lines with the risks posed to public safety and the environment by those pipeline facilities.

Unconventional gas exploration and production have resulted in rapid expansion of the mileage of gathering lines crisscrossing producing regions of the country, with many of those facilities having design and operating characteristics (diameter, operating pressures, gas throughput, etc.) better resembling heavily-regulated gas transmission lines rather than (generally) smaller-diameter and lower-pressure gathering lines built in the past. 86 FR at 63267. Yet most gathering lines have not been subject to any meaningful regulation despite posing increasing risks to public safety and the environment due to the changing nature of gathering lines. Indeed, PHMSA has historically regulated only Type A and B lines — less than 11,700 miles of the total 426,000 miles of gathering lines nationwide — and PHMSA understands there is little State regulation of gathering lines. RIA at 13-14. Recent incidents identified in the administrative record — including on gas gathering and transmission lines located in sparsely-populated areas or on pipelines with diameters smaller than the 8.625" threshold for a Type C line — underscore the need for prompt extension of safety regulations to gas gathering lines that are commensurate with their risks to public safety and the environment. See 86 FR at 63271-72.

The Final Rule is a timely and critical first step in remedying that regulatory gap. The Final Rule extends select safety requirements from 49 CFR part 192 currently applicable to gas transmission and Type A gathering lines to larger-diameter, higher pressure, gas gathering lines: so-called Type C gathering lines, characterized by an outer diameter greater than or equal to 8.625" and an operating pressure producing a hoop stress of 20% or greater of the SMYS (or 125 pounds per square inch gauge (psig) if the SMYS is unknown or for non-metallic pipe). 49 CFR § 192.8(c). Precisely which of those select safety requirements apply to a particular Type C gathering line turns on additional criteria: more burdensome/expensive requirements would apply as that Type C gathering line's diameter increases or its distance from buildings intended for human occupancy decreases. § 192.9(f)(1). Other gathering lines with diameters below the Type C threshold — i.e., those gathering lines posing less acute risk to public safety and the environment — are only subject to 49 CFR part 191 annual and incident reporting requirements necessary to inform future PHMSA decision-making on whether additional regulatory action is warranted to protect public health and safety. § 192.8(c)(3); 86 FR at 63280.

The Final Rule's risk-calibrated approach reflects PHMSA's careful consideration of the benefits (mitigated risks to public safety and the environment) against the costs (including compliance costs) of the Final Rule, and is consistent with PHMSA's obligations under the Pipeline Safety Act. Indeed, the NPRM had proposed that *all* Type C (or, in the NPRM's

[8] Including, but not limited to, Draft and Final Environmental Assessments, a Preliminary Regulatory Impact Assessment ("PRIA") and final Regulatory Impact Assessment ("RIA").

parlance, "Type A, Area 2") gas gathering pipelines would be subject to the same suite of part 192 requirements without differentiation based on the risk to public safety and the environment posed by the design/operating characteristics or location of different pipeline facilities. But, as Petitioners acknowledge, PHMSA moved away from that one-size-fits-all approach leading up to the June 2019 GPAC Meeting — and the administrative record is replete with statements explaining that shift as having been informed by concerns from *numerous* stakeholders regarding potential compliance costs from the rulemaking.[9] And although PHMSA extended part 191 annual and incident reporting requirements to all gas gathering lines (not just Type C lines), the Final Rule explained that these significantly less burdensome reporting requirements would inform future PHMSA decision-making as to whether further extension of part 192 safety requirements is warranted. 86 FR at 63275. Lastly, in the Final Rule PHMSA provided a mechanism to allow operators for whom the new safety requirements prove particularly challenging to seek extensions of pertinent compliance timelines that PHMSA would consider on a case-by-case basis. 86 FR at 63281; §§ 192.8(b)(2), 192.9(g)(4)(ii), 192.18.[10]

In the Final Rule, PHMSA also adjusted the NPRM's methodology for the cost-benefit analysis supporting the rulemaking. Petitioners and other stakeholders had criticized the validity of that portion of the PRIA's methodology for quantifying/monetizing safety benefits anticipated from the NPRM given limitations on the data. As an initial matter, the NPRM and the PRIA did not discuss the benefits of the rulemaking exclusively in quantified/monetized terms.[11] Further, the RIA explicitly acknowledged the limitations of PHMSA's earlier approach and discussed the public safety and environmental benefits of the Final Rule in qualitative terms. RIA at 31-32. PHMSA explained that a qualitative discussion of benefits was appropriate given the limited incident information on gathering lines (as most gathering lines had not been subject to part 191 reporting requirements).[12] PHMSA explicitly concluded that those qualitative benefits justify the costs estimated in the RIA. RIA at 4. PHMSA also underscored in the Final Rule and RIA that the safety and environmental benefits achieved by the Final Rule demand prompt implementation — the longer the regulatory gap is allowed to persist, the greater the risk to public safety and the environment from Type C (and potentially Type R) gathering lines. RIA at 6-7; 86 FR at 63276, 63281.

Consistent with the Pipeline Safety Act, in promulgating the Final Rule PHMSA adopted requirements that will have safety and environmental benefits. PHMSA responded to comments on the NPRM by adjusting the rulemaking's elements to better align with the risks to public safety and the environment posed by Type C gas gathering lines. In addition, in striking a balance between costs and benefits of the rulemaking, PHMSA took into account the assessment of the GPAC's technical experts and industry representatives that the substance of

[9] See, e.g., 86 FR at 63279-80; RIA at 3, 8.

[10] To date, PHMSA has not received a single request for an extended compliance deadline.

[11] For example, the qualitative benefits from regulating Type C gathering lines considered in the NPRM and its supporting documents included safety and environment benefits, reassurance to the general public, operating efficiencies, extended pipeline life, and regulatory efficiency. See, e.g., PRIA at 150.

[12] PRIA at 145; RIA at 6, 30, 32. PHMSA further notes that, because natural gas pipeline events are generally low-frequency, high-consequence events, the benefits (e.g., avoided incidents or avoided methane emissions) anticipated from new safety regulations do not lend themselves to quantification.

the requirements ultimately adopted in the Final Rule were technically feasible, reasonable, cost-effective, and practicable.[13] Lastly, PHMSA explicitly acknowledged that adjustments to its cost-benefit methodology were introduced in response to concerns articulated by the Petitioners and other stakeholders regarding the validity of PHMSA's quantification of benefits in the PRIA.

B. The Petitioners' Criticisms of PHMSA's Calculation of Compliance Costs — Including Petitioners' Reliance on a Severely Flawed Cost-Benefit Analysis — Are Misplaced.

PHMSA finds the Petitioners' criticisms of its methodology in evaluating the potential costs of the Final Rule unconvincing. PHMSA addresses each of the Petitioners' principal criticisms in turn below.

Much of the Petition consists of allegations that PHMSA failed to respond to a cost study that Petitioners had submitted in the rulemaking.[14] However, even cursory review of the ICF Study reveals it is riddled with flaws (which flaws are discussed at length within the enclosed Appendix, incorporated herein by reference) and rests on stale information regarding the content of the rulemaking.[15] The Petition nowhere acknowledges these shortcomings in the ICF Study.

Petitioners criticize PHMSA's reliance on 2006 IPAA data[16] regarding the costs of certain part 192 safety requirements extended to Type C lines by the Final Rule, asserting that the IPAA data is old (15-year-old) data while the ICF Study data is newer and therefore better. However, that assertion fails to take into account the fact that PHMSA adjusted the 2006-vintage cost values in the IPAA data for inflation within the PRIA (to 2015 dollars) and RIA (to 2018 dollars). PRIA at 103; RIA at 16. Further, as explained in more detail in the enclosed Appendix, the ICF Study is not useful for PHMSA's cost analysis in this rulemaking. In contrast, the IPAA numbers (as adjusted) remain sound estimates for the costs associated with certain elements of the rulemaking, as industry provided the IPAA data in connection with a 2006 rulemaking imposing part 192 requirements on gas gathering lines in Class 2, 3, and 4 locations and this Final Rule extends some of those provisions to Type C gathering lines.[17] Given that those industry cost

[13] The GPAC reached that conclusion notwithstanding the availability of Petitioners' concerns in the rulemaking docket and Petitioners' expression of those concerns during the GPAC Meeting. See, e.g., Transcript of GPAC Meeting at 84:19-87:10, 145:6-147:5, 183:9-185:17, 250:1-251:13. PHMSA further submits that since the GPAC Meeting, supply constraints have driven representative (Henry Hub spot price) natural gas prices to *double* (relative to prices at the time the ICF Study was commissioned), thereby reinforcing the GPAC's conclusions regarding the cost-effectiveness of the elements in the Final Rule. See Energy Information Administration, "Henry Rub Natural Gas Spot Price", https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm (last visited Mar. 15, 2022) (comparing June 2016 prices and February 2022 prices).

[14] ICF International, "Cost and Benefit Impact Analysis of the PHMSA Natural Gas Gathering and Transmission Safety Regulation Proposal" (July 1, 2016) (the "ICF Study"). Petitioners' characterization in various filings of the ICF Study as "independent" is false: it was commissioned by API. Nor did ICF International report that any sort of peer review was conducted for the ICF Study.

[15] PHMSA further notes that the Petition does not attempt to update the analysis in the ICF Study to reflect the content of the Final Rule.

[16] Petition at 23-24.

[17] See Final Regulatory Evaluation: Regulated Natural Gas Gathering Lines Rule (RIN 2137-AB15), Doc. No. PHMSA-RSPA-1998-4868-0208 (Sept. 7, 2006).

estimates were submitted by operators with gas gathering pipelines that were well-positioned to understand financial consequences of implementation (and highly-motivated to demonstrate the costs of that earlier rulemaking were greater than PHMSA had estimated), the IPAA values likely remain sound — and potentially higher than expected unit costs of compliance — when adjusted for inflation as accomplished in the RIA.

Petitioners also characterize as unsupported an assumption in the RIA that 90% of newly-designated Type C lines of outer diameter less than or equal to 16" would be eligible for the exceptions at § 192.9(f) from leakage survey, public awareness, line marker, and corrosion control requirements.[18] PHMSA disagrees with Petitioners' contention.[19] By definition, Type C lines are located in Class 1 areas in which there are fewer than 10 buildings intended for human occupancy within 660 feet of either side of a sliding 1-mile segment of pipeline. 49 CFR §§ 192.5 and 192.8. PHMSA drafted the PIR here conservatively and (employing best professional judgment) expects that PIRs for Type C gathering lines with outer diameter less than or equal to 16" will generally have PIRs less than 660 feet. See 86 FR at 63283. This parameter, when considered along with the other § 192.9 exceptions and the fact that (at the time of construction) most Type C gathering lines are located in production areas with low population density, support PHMSA's conclusion that about 90% of Type C lines with outer diameter less than or equal to 16" would be subject to at least one of § 192.9(f)'s exceptions from leakage survey, public awareness, line marker, and corrosion control requirements.

PHMSA also finds unconvincing Petitioners' criticism of the RIA's assumptions that 97% of newly-designated Type C gas gathering lines and 80% of newly-designated Type R gathering lines would have minimal part 191 and 192 compliance costs.[20] As explained in greater detail in the Appendix, PHMSA understands that since the publication of the NPRM, consolidation within the gas gathering and transmission sectors has accelerated and will continue: a principal

[18] PHMSA acknowledges that the RIA suggested that § 192.9(f) consisted of only a single exception to the part 192 leakage survey, public awareness, line marker, and corrosion control requirements: the so-called "PIR" exception at § 192.9(f)(i)(1). However, § 192.9(f) more precisely contains two additional exceptions: an alternative method at § 192.(e)(1)(ii) (based on a pipeline's class location unit) for determining the absence of buildings intended for human occupancy, and another exception at § 192.9(f)(2) for short (40-foot or less) replacements on existing pipelines.

[19] PHMSA notes that the PIR exception incorporated within the Final Rule was suggested by GPA Midstream to "ensure that PHMSA's new regulations satisfy the cost-benefit provision in the Pipeline Safety Act." GPA Midstream Association, "Supplemental Position Paper on 'Pipeline Safety of Gas Gathering Pipelines,'" Doc. No. PHMSA-2011-0023-0453, at 2-5 (Dec. 4, 2018).

[20] Petitioners reference in support of these arguments a recent report of the Government Accountability Office ("GAO"). See Supplemental Filing in Support of Motion to Stay, Doc. No. PHMSA-2011-0023-0498 (posted Mar. 14, 2022) (referencing GAO, "Pipeline Safety: Operators of Natural Gas and Hazardous Liquid Gathering Lines Face Data Collection Challenges," GAO-22-104817 (Jan. 2022)). However, industry representatives' reported (to the GAO) lack of awareness regarding the contents of the NPRM are hard to square with the widespread interest of gas gathering operators and their trade associations in the decade-long development of this rulemaking. Petitioners alone have submitted more than 600 pages of written material. And, to the extent that compliance efforts by operators with older gathering facilities with poor records may prove challenging, the Final Rule provides that such operators may seek extensions of pertinent part 192 compliance timelines. See 86 FR at 63281. PHMSA further submits that any operator's ignorance of the minimal information regarding the location and material operating design and material characteristics of their assets — and by extension, the risk those assets pose to public health and safety — underscores the urgency of the Final Rule's safety and reporting requirements.

dimension of that consolidation is that many operators have expanded their footprints across those two segments of the midstream sector.

For the reasons outlined above, PHMSA remains confident in the Final Rule's conclusion that its costs justify its benefits, and that the Final Rule's regulatory amendments are otherwise technically feasible, reasonable, cost-effective, and practicable. Although PHMSA in the enclosed Appendix identifies assumptions that could (if applied) yield adjustments to the costs of the Final Rule as characterized in the RIA, PHMSA understands those increased costs are not so large (either on a per-element basis or in the aggregate) that they would materially alter the balance struck by the Final Rule between costs and the significant safety and environmental benefits expected from introducing meaningful safety requirements for ca. 90,000 miles of Type C lines that have largely escaped meaningful safety regulation, and minimal reporting requirements for the ca. 400,000 miles of Type R gathering lines that could warrant robust safety regulation in the future.

C. PHMSA Evaluated Alternatives to the Final Rule and Provided an Adequate Explanation of the Alternative Adopted in the Final Rule.

Petitioners criticize PHMSA's decision to extend select part 192 safety requirements to certain gas gathering lines with outer diameter less than or equal to 12.75" (aka "Alternative 4" in the RIA), rather than adopt a narrower rulemaking focused on extending part 192 requirements to a subset of the largest (diameter greater than 12.75") Type C lines (aka "Alternative 2 in the RIA). Petition at 23. The gravamen of Petitioner's argument is that PHMSA failed to adequately explain how the benefits of the Final Rule and its costs outweigh the benefits of Alternative 2, which Petitioners claim provides the greatest safety benefits per mile at roughly half the cost of the alternative adopted in the Final Rule.

However, PHMSA need not adopt an alternative with the lowest costs on either an absolute sense or on a per-mile basis if doing so would forego important public safety and environmental benefits. As explained above, the record demonstrates that gas gathering pipelines in sparsely-populated areas with diameters much smaller than the 12.75"-diameter threshold in Alternative 2 already pose significant risks to public safety and the environment. The longer those pipeline facilities go without meaningful safety regulation, the greater the cumulative risk to public safety and the environment. Those benefits from the Final Rule's broader safety requirements would not be achieved under the alterative regime Petitioners advance.

PHMSA acknowledges the Final Rule's broader safety requirements may necessitate some financial cost to affected operators. However, the record demonstrates that PHMSA considered and balanced those (qualitative) anticipated benefits against the (quantified) expected costs and determined that the Final Rule's adoption of Alternative 4 is appropriate.[21] And, as noted above, PHMSA is not alone in reaching that conclusion — the GPAC's technical

[21] Alternative 4, as adopted in the Final Rule, would also entail lower part 191 compliance costs than Alternative 2. Where the Final Rule adopts simplified annual and incident reporting forms for use by Type R operators, Alternative 2 would have applied existing part 191 reporting requirements to Type R lines. See 86 FR at 63276; RIA at 10-11.

experts and industry representatives assessed the substantive requirements adopted in the Final Rule as technically feasible, reasonable, cost-effective, and practicable.

D. PHMSA Adequately Considered the Final Rule's Impact on Small Entities.

The administrative record belies Petitioners' suggestion that PHMSA gave short shrift to the potential impact of the Final Rule on small entities. Petition at 17. Rather, PHMSA acknowledged in the RIA that the Final Rule's requirements could adversely affect small entities, with compliance costs falling more heavily on some small entities than others. RIA at 35. However, because the *industry-wide* compliance costs for the rule were relatively low (ca. $13.8 million/year), PHMSA exercised its best professional judgment in estimating that the adverse effects on small entities in particular would fall short of the RFA threshold of a "significant economic impact on a substantial number of small entities." PHMSA expects that the recent spike in natural gas commodity prices could also make small entities less vulnerable to any incremental compliance costs arising from the Final Rule.[22]

PHMSA also submits that any such adverse economic impact would also be mitigated by elements of the Final Rule and the business practices of many small gathering operators. The provisions incorporated in the Final Rule allow any operator — including small entities — to seek extensions of compliance timelines for pertinent part 192 safety requirements. 86 FR at 63281. Further, PHMSA subject matter experts note that small gathering operators will often control their costs by hiring external consultants rather than hiring new staff to ensure compliance with pertinent regulatory requirements as larger operators would. As a result, some of the fixed costs associated with compliance efforts would be borne indirectly through the external consultants and shared by other pipeline operators employing the same consultants. PHSMA subject matter experts also understand that operators with very small-mileage systems typically operate them within an integrated operation that can include some combination of wellhead operations, processing operations and/or transmission pipelines. Rather than deriving income from the toll services of the pipeline, those gathering pipelines are operated as a component of an integrated system delivering system-wide revenues while absorbing incremental new compliance costs on individual components of the system.

Although PHMSA in the enclosed Appendix identifies some adjustments to the potential costs of the Final Rule as characterized in the RIA and the number of operators (including small operators), PHMSA understands those adjustments would not be so large (either on a per-element basis or in the aggregate) that they would require PHMSA to reconsider its certification in the RIA that the Final Rule will not have a significant impact on a substantial number of small entities.

E. The GPAC Provided Peer Review of PHMSA's Risk Assessment Consistent with Statutory Requirements.

PHMSA also disputes Petitioners' reading of the Pipeline Safety Act language regarding the role of the GPAC in PHMSA rulemaking. Petitioners assert that PHMSA's development of

[22] See U.S. Energy Information Administration, "Henry Hub Natural Gas Spot Price," https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm (last visited Mar. 15, 2022).

the Final Rule was procedurally deficient because PHMSA did not provide, and the GPAC did not review, a "risk assessment and other analyses," and the GPAC did not subsequently generate and publish a stand-alone report speaking to whether the Final Rule was technically feasible, reasonable, cost-effective, and practicable. Petition at 7, 18-19. Petitioners contend that these alleged procedural deficiencies prevented PHMSA from evaluating the costs and benefits of the Final Rule as required by statute, because they assert that the GPAC did not consider the PRIA or any other "risk assessment." Id. at 7, 13.

The administrative record for this rulemaking demonstrates that, consistent with pertinent statutory requirements, the GPAC reviewed and provided meaningful feedback on pertinent cost-benefit and risk assessment information for this rulemaking. The Federal Register notice announcing the June 2019 GPAC Meeting explicitly noted the GPAC would be considering "the gathering line component [of the 2016 NPRM] proposed rule. . . *and the associated regulatory analysis*" (emphasis added).[23] As described in the notice, the "gathering line component" closely resembles the Final Rule that was adopted: repeal of use of API Recommended Practice 80 for gathering lines; application of Type B requirements along with emergency requirements to newly regulated greater than 8" Type A gathering lines in Class 1 locations, and extension of the reporting requirements to all gathering lines. PHMSA made available to the public a detailed presentation in advance of the meeting[24] which, among other things, addressed the risks to public safety and the environment from the non-regulatory option of the status quo, and described the comments received (including distillation of a range of alternatives suggested in those comments) and potential revised regulatory language for the GPAC to consider in light of those comments. As evidenced by the meeting transcript from the June 2019 meeting, over two days, the GPAC discussion centered on discerning an appropriate balance between risks (e.g., avoided safety and environmental harms) and compliance costs associated with each of the material elements of the rulemaking as well as alternative approaches proposed by GPAC members (including, implicitly, no action at all on various elements of the rulemaking). Within a month of the meeting's conclusion, PHMSA posted the transcript and voting slides to the PHMSA website in satisfaction of the reporting requirement of 49 U.S.C. 60115(c).

Petitioners' position is also inconsistent with longstanding agency practice. Indeed, Petitioners' earlier filings concede that PHMSA has employed the same methodology employed in this rulemaking for the better part of a decade, specifically: the GPAC meeting schedule and purpose is announced in the Federal Register; the meeting agenda and accompanying presentation materials are made available to the GPAC members and the public in advance of the meeting; and the GPAC considers its post-meeting report to consist of the slide deck generated by PHMSA staff along with transcript and slides memorializing the content of the

[23] "Notice of Advisory Committee Meeting," 84 FR 14724, 14725 (Apr. 11, 2019). The PRIA — and comments thereon — had by the publication of that notice been available in the rulemaking docket since 2016.

[24] Doc. No. PHMSA-2011-0023-0461 (GPAC Meeting voting slides); Doc. No. PHMSA-2011-0023-0463 (GPAC Meeting slides posted in advance). The GPAC Meeting materials are also made available to the public on a meeting-specific webpage on the PHMSA website (https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=143), with full transcripts available for June 25 (https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1070) and June 26 (https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1071).

meeting and the GPAC's voting results.[25] Those same filings of Petitioners also suggest that PHMSA's earlier practice did not conform with the rigid scheme the Petitioners insist the statute clearly demands.[26]

The statute does not prescribe a particular form for the "risk assessment" and cost-benefit analysis that PHMSA provides to the GPAC for review. Nor does the statutory text (at 49 U.S.C. 60115(c)(2) and 49 U.S.C. 60115(c)(2)) prohibit or prescribe a particular form of the materials generated by GPAC. Rather, legislative history supports a more flexible reading of the materials presented to and endorsed by GPAC: Congress was focused less on the ***form*** (including number) of the GPAC's reports than their ***content and quality***. When incorporating both the GPAC consultation provisions within the 1968 Pipeline Safety Act (49 U.S.C. 60115) and subsequently revising those requirements in 1996 to codify the GPAC's review of PHMSA-generated risk assessments (49 U.S.C. 60102(b)(4)), the legislative history evinces a choice of statutory text establishing baseline requirements for factors (technical feasibility, reasonability, cost-effectiveness, and practicability) and methodology (risk assessments) the GPAC should employ in providing meaningful review of proposed PHMSA rulemakings.[27] Legislative materials associated with the 1996 revisions to the Pipeline Safety Act underscore this point, as they characterize the risk assessment review obligation introduced at 49 U.S.C. 60102(b)(4) as reinforcing the GPAC's historical reviews of PHMSA's proposed rules pursuant to 49 U.S.C. 60115 rather than imposing a requirement for PHMSA or the GPAC to generate entirely new reports.[28]

As explained above and as demonstrated in the administrative record for this rulemaking, the GPAC thoroughly assessed the risks, costs, and benefits of the rulemaking and discussed alternative approaches. After the GPAC's two-day meeting, in which Petitioners participated and reiterated their concerns, the GPAC concluded that the material elements of the Final Rule struck an appropriate balance between pertinent risks, costs, and benefits. In addition, after thoroughly evaluating the risk assessment information that PHMSA provided, the GPAC provided certain recommendations. Accordingly, the GPAC adequately reviewed PHMSA's risk assessment for this rulemaking, consistent with its statutory obligations.

II. PHMSA DECLINES TO ADOPT THE REVISIONS TO THE FINAL RULE PROPOSED IN THE PETITION.

As discussed above, the Final Rule is the culmination of a decade-long effort by PHMSA to ensure common-sense part 191 reporting and part 192 safety measures apply to gas gathering lines that had previously escaped any meaningful safety and reporting requirements despite the risks they pose (or could pose) to public safety and the environment. The Final Rule avoids a one-size-fits-all approach, instead calibrating those requirements based on the

[25] See API & GPA Midstream, "Supplemental comments of the GPA Midstream and Association and American Petroleum Institute on 'Pipeline Safety: Safety of Gas Gathering Pipelines,' RIN2137-AF38, June 2019 Gas Pipeline Advisory Committee Meeting," Doc. No. PHMSA-2011-0023-0465, at 9-10 (Sept. 30, 2019).
[26] See id. at 10 n. 35 (characterizing the then-Acting Director of the Office of Pipeline Safety as "express[ing] concern that the GPAC was not producing a robust report" in 1977).
[27] See, e.g., H.R. Rep. No. 90-1390, at 31 (1968); S. Rep. No. 104-334, at 3 (1996).
[28] See H.R. Rep. No. 104-110, pt. 1, at 12 (1995); S. Rep. No. 104-334, at 3 (1996).

magnitude of risks posed by gathering lines (as a function of design and operating characteristics and location) and the compliance costs that would be borne by operators: as a gathering line's throughput capacity and proximity to buildings intended for human occupancy increase, so do the Final Rule's safety requirements and reporting requirements. The Final Rule also incorporates a mechanism by which operators can seek extensions of compliance deadlines for part 192 safety requirements on a case-by-case basis in response to stakeholder concerns regarding compliance challenges.

PHMSA therefore declines to modify the Final Rule's substantive requirements and compliance timelines as requested by Petitioners. The Final Rule's elements reflect PHMSA's reasoned decision-making regarding the appropriate balance between potential compliance costs and anticipated public safety and environmental benefits — a balance endorsed by the technical experts on the GPAC. The administrative record demonstrates that the Type C gathering lines that are the subject of this rulemaking pose risks to public safety and the environment comparable to those posed by highly-regulated gas transmission lines. Delayed implementation or modification of the part 192 safety requirements of the Final Rule prolongs or tolerates those risks nationwide. Similarly, delayed implementation of the Final Rule's reporting requirements, which are not onerous, will frustrate PHMSA's timely determination regarding whether additional part 192 safety requirements are warranted for Type C gathering lines, as well as whether Type R gathering lines warrant extension of part 192 safety requirements to those pipeline facilities. The Petitioners' requested modifications to the Final Rule would, therefore, be inconsistent with PHMSA's statutory obligations to protect public safety and the environment.

However, as noted in the introduction, PHMSA acknowledges that Petitioners raise concerns regarding certain language in the Final Rule that would benefit from clarification. PHMSA discusses its resolution of those concerns in the detailed discussion of the Petitioners' specific requests for revision of the Final Rule below.

A. PHMSA Declines to Amend the Final Rule to Adjust Compliance Timelines for Part 191 Reporting Requirements in Light of the Part 192 Deadline for Designating Type C Gathering Lines.

Petitioners allege that the Final Rule's compliance timelines for part 191 reporting requirements for newly-designated Type C lines are incompatible with the deadline in the Final Rule at § 192.8(a) for an operator to classify a pipeline facility as a Type C line. Petition at 25.

PHMSA declines to modify either its part 191 reporting requirements or § 192.8, as there is no conflict between those provisions. The Final Rule requires Type C lines to comply with part 191's annual (§ 191.17(a)(1)) and incident (§ 191.15(a)(1)) reporting requirements. With respect to the former, the Final Rule at § 191.17(a)(1) requires operators of Type C lines to submit their first annual report no later than March 2023 — five months after § 192.8(b)(1) of the Final Rule requires operators to have classified those lines as Type C or Type R lines. As for incident reporting, after the rulemaking's May 16, 2022 effective date, gathering line operators have to submit an incident report whether they are a Type C or a Type R gathering line — meaning that the classification requirement at § 192.8(a) would not affect whether they must submit an incident report at all. See § 191.15(a).

PHMSA also disagrees with Petitioners that the information Types C and R gathering line operators will have to provide in required annual and incident reports imposes a hardship. The information that PHMSA demands within its Types C and R incident and annual report forms is not obscure; rather, it is the minimal sort of information — regarding a gathering pipeline's location, design, and material characteristics — that ***any*** responsible business owning assets known to be potentially hazardous would maintain in ordinary course.[29] This is particularly true here, as PHMSA has been considering extending reporting requirements to unregulated gathering lines since at least the 2016 NPRM, with further potential details provided during the June 2019 GPAC Meeting. Nevertheless, for Type R operators, the Final Rule provides simplified reporting forms to reduce burdens should they have inadequate documentation. 86 FR at 63275-76. In contrast, PHMSA understands Type C operators to be generally well-positioned to provide more complete information in their annual reports, as those lines are often of more recent vintage. As explained above, the Final Rule's extension of part 191 incident and reporting requirements to previously-unregulated gathering lines is essential to PHMSA's ability to perform its public safety and environmental mission, as the information in those reports help inform timely response to incidents and future PHMSA regulatory oversight of gathering lines.

B. PHMSA Will Make an Editorial Change to the Final Rule Clarifying that Types C Gathering Lines Need Not Submit Safety-Related Condition Reports.

Petitioners ask PHMSA to codify in regulation statements in the Final Rule assuring Types C and R gathering line operators that the § 191.23 requirement to report MAOP exceedances and other safety-related conditions are not required for Type C and R lines that are not required to establish an MAOP pursuant to §§ 192.9 and 192.619. Petition at 26. PHMSA agrees that there is value in ensuring this exception explicitly discussed in the Final Rule preamble (at 86 FR at 63275) is codified within regulation, and will incorporate that regulatory revision in a forthcoming Federal Register notice.

C. PHMSA Declines to Amend the Final Rule to Limit the 10-Mile Threshold for Incidental Gathering Lines to Newly Constructed Lines.

Petitioners ask PHMSA to limit the 10-mile threshold for applying the "incidental gathering" definition to newly-constructed lines, rather than to all new, replaced, relocated, or otherwise changed lines as provided in the Final Rule. Petition at 26. Petitioners contend that lines currently qualifying as incidental gathering would suffer significant practical and financial hardships should the replacement, relocation, or otherwise change of those lines after the May 16, 2022 effective date of the Final Rule trigger their regulation as part 192 transmission lines pursuant to Final Rule's change to the definition of "incidental gathering" at § 192.8(a)(5).

[29] PHMSA similarly does not understand the Pipeline Safety Act contemplates that PHMSA would shield from long-overdue Federal safety and reporting requirements those gas gathering pipeline facilities acquired without meaningful due diligence on the physical specifications and condition of such assets. Indeed, such an approach would reward — even encourage — such transactions, thereby prolonging exposure of the public and the environment from the risks posed by those gas gathering facilities.

PHMSA declines to modify the Final Rule as requested. The administrative record demonstrates that the historical definition of "incidental gathering" has been abused such that many lines that currently function as transmission lines escape part 192 safety regulations despite the risks they pose to public safety and the environment. 86 FR at 63278-79. That a subset of those existing lines — those that are replaced, relocated or otherwise changed — would now be subject to part 192 regulatory requirements commensurate with those risks is entirely reasonable. Further, as discussed in the RIA and elaborated in the enclosed Appendix, PHMSA expects the number of operators who would be captured by the revised regulatory definition to be small. RIA at 23.

However, PHMSA acknowledges the practical and financial challenges that those operators captured by the revised definition of "incidental gathering" could encounter. PHMSA also notes that if operators would trigger substantially more burdensome regulatory requirements when they repair, relocate, or change their lines, they may choose to delay needed safety-enhancing maintenance activity. Both of these practical challenges may in turn complicate enforcement by PHMSA's State partners. With these considerations in mind, PHMSA understands that there is value in issuing a limited enforcement discretion providing operators assurance that PHMSA will not — before PHMSA is able to consider the issue in a forthcoming rulemaking — enforce the 10-mile threshold within the Final Rule's revised definition of "incidental gathering" in connection with projects replacing, repairing, or changing those lines existing on May 16, 2022 that are currently designated as "incidental gathering" lines. PHMSA will memorialize that enforcement discretion in a forthcoming Federal Register notice (in parallel communicating that notice to PHMSA's state partners) and consider whether further revisions to the regulatory definition of "incidental gathering" is appropriate.

D. <u>PHMSA Declines to Amend the Final Rule to Extend Deadlines for Designating Existing Gathering Lines as Type C Gathering Lines</u>.

Petitioners request PHMSA amend the Final Rule's November 2022 compliance deadline at § 192.8(b)(1) for designating existing gathering lines as Type C to stagger pertinent compliance timelines based on outer diameter such that the largest (with outer diameter 12.75" or greater) gathering lines would have to classify their lines as Type C lines no later than May 16, 2023 (an additional six months compared to the Final Rule) and other, smaller lines (with outer diameter between 8.625" and 12.75") no later than May 16, 2026 (an additional 3 years and six months). Petition at 27-28. Petitioners contend that the Final Rule's timeline would impose financial and practical hardships on affected operators, who would have to come into compliance with a number of part 192 requirements in short order. Petitioners characterize the Final Rule's § 192.8(b)(1) classification timeline as inconsistent with compliance timelines in an earlier PHMSA rulemaking designating Type A and B gathering lines, and caution that the Final Rule's provision allowing operators to seek ad hoc extensions of Type C classification requirements creates regulatory uncertainty rather than reducing compliance burdens.

PHMSA declines to modify the Final Rule as requested. As explained above and in a number of places in the administrative record, all Type C lines pose risks to public safety and the environment similar to transmission lines, yet at present avoid any meaningful part 191

reporting and part 192 safety requirements. The longer that regulatory gap persists, the greater the risk to the public and the environment.[30] Although PHMSA acknowledges the Final Rule's timeline for designation of gathering lines as Type C may result in compliance costs and challenges for affected operators,[31] PHMSA has concluded (as explained above and in the enclosed Appendix) that those compliance costs are not nearly as high as those calculated in the ICF Study relied on by the Petitioners and would, in any event, be justified by the significant safety benefits captured by the Final Rule. PHMSA also notes that the Final Rule incorporates flexibilities allowing for operators to seek extensions of pertinent timelines on a case-by-case basis — flexibility that operators admittedly should not assume PHMSA will grant automatically, but which can in practice reduce compliance hardships for particular operators. PHMSA further notes that the Petition provides no explanation as to why the particular compliance deadlines they have proposed would avoid imposing the same compliance burdens and challenges — albeit only at a later date — than the Final Rule's November 2022 compliance deadline.

Lastly, consistent with the discussion in section II.A above, much of the information that gathering line operators will review to determine whether an existing gathering line is indeed a Type C line is the sort of information that responsible businesses owning assets known to be potentially hazardous would maintain in ordinary course, and this rulemaking has been in development for over a decade, with operators (and their trade associations) being broadly aware of its potential contents since at least 2016.[32]

E. PHMSA Declines to Amend the Final Rule to Extend Part 192 Safety Requirement Compliance Deadlines for Newly-Designated, Existing Type C Gathering Lines.

Petitioners request PHMSA amend the one-year (May 16, 2023) compliance deadline at § 192.9(g)(4) in the Final Rule to allow newly-designated, existing Type C gathering lines to stagger those compliance timelines based on outer diameter. Petition at 28. Specifically, Petitioners request that the largest (with outer diameter 12.75" or greater) Type C gathering lines be allowed to comply with part 192 safety requirements no later than May 16, 2025 (an additional three years compared to the Final Rule) and other, smaller Type C gathering lines (with outer diameter between 8.625" and 12.75") be allowed to comply with part 192 safety

[30] The particular compliance deadlines recommended by operators — in May, two months *after* the annual report submission deadline in March — mean that PHMSA would receive the initial Type C annual reports for newly-designated Type C gathering lines with (1) outer diameter 12.75" or greater in March 2024 (vice March 2023 in the Final Rule) and (2) outer diameter between 8.625" and 12.75" in March 2027 (vice March 2023 in the Final Rule). Petitioners assert that PHMSA's regulatory oversight purposes could be satisfied by requiring operators benefitting from the deadline extensions to submit short-form Type R annual reports — but PHMSA chose the more fulsome Type C annual report forms to provide more meaningful information for identifying systemic emerging issues on Type C lines.

[31] Petitioners' analogy to the compliance timelines for PHMSA's 2006 rulemaking requiring classification of Types A and B gathering lines is inapposite. Petition at 28. That earlier rulemaking introduced a scheme for classifying and regulating different species of gathering lines based on risks they posed to the public and the environment. The Final Rule's revisions do not act against so blank a canvas as that 2006 rulemaking; rather, the Final Rule's provisions build on that pre-existing classification scheme by ensuring a subset of the part 191 and 192 safety requirements imposed on gathering lines in the 2006 rulemaking are extended to Type C lines.

[32] See supra at section I.

requirements no later than May 16, 2028 (an additional 5 years). Petitioners' justification for their preferred changes rehash their arguments in support of their request that PHMSA extend the Final Rule's compliance deadlines for designating Type C gathering lines discussed in section II.D above.

PHMSA declines to modify the Final Rule as requested for the same reasons (which reasons are incorporated herein by reference) it refused in section II.D above to extend the timelines for gathering operators to designate their existing gathering lines as Type C gathering lines. The Final Rule requires Type C operators comply with pertinent part 192 safety requirements by May 16, 2023. 49 CFR 192.9(g)(4)(i). This compliance deadline is six months after the designation of a gathering line as a Type C line (which 49 CFR 192.8(b)(1) requires by November 16, 2022) — a *year* from the effective date of the Final Rule as a whole, roughly *18 months* since issuance of the Final Rule, and *nearly four years* since these part 192 safety requirements were discussed as a potential regulatory approach at the June 2019 GPAC Meeting. In any event, operators on whom the Final Rule's timelines would impose hardship can seek an extension of the May 2023 compliance timeline. Lastly, the Petition provides no explanation as to why the particular compliance deadlines they have proposed would avoid imposing the same compliance burdens and challenges — albeit just at a later date — than the Final Rule's May 2023 compliance deadline.

F. PHMSA Declines to Amend the Final Rule to Extend Part 192 Safety Requirement Compliance Deadlines if a Change in Class Location, MAOP, or Dwelling Density Results in Either Re-designation as a Type C Gathering Line or Triggers Additional Part 192 Safety Requirements.

Petitioners request PHMSA amend the one-year compliance deadline at § 192.9(g)(5) for gathering lines that become newly-designated as Type C gathering lines, or existing Type C lines that become subject to additional part 192 safety requirements, as a result of a change in class location, proximity to occupied buildings, or MAOP. Petition at 29. Petitioners propose an extension of an additional one to two years to the compliance period, contending such a change would better align the Final Rule with existing PHMSA requirements at § 192.611(d) governing the attachment of additional part 192 safety requirements in the event of a class change. Petitioners contend this alignment would reduce administrative burdens on operators.

PHMSA declines to modify the Final Rule as requested. The Final Rule's one-year compliance timeline for newly-designated Type C lines is the same as the compliance timeline at § 192.9(e)(3) for gathering lines newly-designated as Type B to comply with a similar suite of part 192 safety requirements that could apply to Type C lines under the Final Rule. Further, as explained above, the longer Type C lines warranting additional part 192 safety requirements are not subject to those requirements, the greater the cumulative risk to public safety and the environment from the regulatory gap addressed by the Final Rule.

G. PHMSA Agrees to Clarify that Operators May Use a Default Specified Minimum Yield Strength ("SMYS") as Contemplated by Existing Regulations in Identifying Type C Gathering Lines.

Petitioners request PHMSA revise the Final Rule to codify in regulation that operators may use a default yield strength of 24,000 pounds-per-square-inch (psi) in calculating the SMYS of a gathering line for the purpose of determining whether it is a Type C gathering line pursuant to § 192.8(c).[33] Petition at 29. Petitioners note that use of that default yield strength in calculating SMYS is permitted in PHMSA regulations at § 192.107(b)(2).

PHMSA declines to modify the Final Rule as requested as Petitioners are correct that PHMSA regulations at § 192.107(b)(2) already permit the use of a default yield strength in determining SMYS. However, PHMSA agrees that there could be value in clarifying this flexibility. PHMSA will, therefore, issue a Federal Register notice to clarify that operators may use the default yield strength specified at § 192.107(b)(2) in calculating SMYS in connection with determining whether a gathering line is a Type C line pursuant to § 192.8(c).

H. PHMSA Declines to Amend the Final Rule to Exempt Type C Gathering Lines with Outer Diameter Less than 12.75" from Enhanced Part 192 Safety Requirements.

Petitioners request PHMSA revise the Final Rule to exempt Type C gathering lines with outer diameter less than 12.75" and who have a building intended for human occupancy within the PIR or class location unit from requirements at § 192.9(e)(1) subjecting those lines to heightened part 192 safety requirements (specifically, corrosion control, line markets, leakage surveys and public awareness programs). Petition at 30. Petitioners contend that PHMSA has not demonstrated an adequate safety basis for extending burdensome part 192 requirements to those lines.

PHMSA declines to modify the Final Rule as requested. As explained above in section I.A, the administrative record documents the risks to public safety and the environment from Type C gathering lines with outer diameter of less than 12.75". The public safety risks of those lines are amplified when a building intended for human occupancy is known to be within the PIR. The part 192 regulatory requirements at issue here, moreover, are particularly effective for managing those public safety and environmental risks from common modes of failure for Type C gathering lines: line markers and public awareness programs are critical for avoiding excavation damage, leak surveys enable identification and cure of leaks before they become catastrophic failures, and corrosion control addresses the most frequent root cause of pipeline incidents, particularly on gas gathering lines. Additionally, as explained at length above and in the enclosed Appendix, the ICF Study overestimates compliance costs of this and other elements, and operators can seek to mitigate what compliance costs and challenges do exist by availing themselves of the Final Rule's procedural machinery for requesting an extension of compliance deadlines.

I. PHMSA Declines to Amend the Final Rule to Expand the Exception from Part 192 Design and Installation Requirements for Replacement or Relocation of 40-Foot-Long Segments of Existing Type C Gathering Lines.

[33] Petitioners refer to § 192.8(e); however, PHMSA understands the pertinent regulatory provision to be § 192.8(c).

Petitioners request PHMSA revise an exception at § 192.9(f)(2) in the Final Rule from part 192 design and installation requirements for replacement, relocation, or other changes of short (40-foot or less) segments of existing Type C gathering lines. Petition at 30. Petitioners assert that operators generally do not replace or relocate segments of pipe that are only 40-foot long, and that operators may struggle to comply with certain part 192 design and installation requirements when installing such short segments of pipe. Petitioners comment that lowering a 40-foot segment of pipeline would require replacing 230 feet of adjacent pipeline, presumably to comply with depth of cover requirements in § 192.327. Although Petitioners propose expanding the length of Type C pipelines eligible for this exception to 500 feet, they do not articulate a reason for the choice of that particular value.

PHMSA declines to modify the Final Rule as requested. As explained in various places in the administrative record, part 192 design installation requirements are an essential tool for management of public safety and environmental risks from currently unregulated Type C gathering lines. PHMSA understands that exceptions to those requirements should consequently be narrow. PHMSA chose the 40-foot limitation, corresponding to the typical length of a segment of steel pipe, in the exception at § 192.9(f)(2) after employing its best professional judgment to conclude that value would capture the safety and environmental benefits from a strong default rule that part 192 design and installation requirements would apply to most repair/replacement projects without creating perverse incentives by discouraging operators from safety-enhancing repair-by-replacement strategies on individual segments of pipe. PHMSA understood that most gathering line repair and replacement projects involve segments longer than 40 feet, and intended the Final Rule as issued to extend the safety benefits that result from the part 192 requirements to most of those projects by requiring the installation of more robust, part 192-compliant pipe.

Additionally, the depth of cover example (the only example provided to support Petitioners' requested expansion of the 40-foot exception in the Final Rule) is already covered by the scope of the exception as written. However, § 192.327 is a subpart G construction standard and is therefore explicitly covered by the exception in § 192.9(f)(2). In this example, lowering the replacement segment at all is therefore not required and the Petitioner's concerns are adequately addressed by the existing scope of the exception.

J. <u>PHMSA Declines to Amend the Final Rule to Remove a Requirement that Leak Surveys on Certain Type C Gathering Lines Be Performed with Leak Detection Equipment</u>.

Petitioners request PHMSA eliminate the requirement at § 192.9(e)(1)(vii) of the Final Rule that operator leak detection surveys on certain Type C gathering lines be performed with leak detection equipment. Petition at 31. Petitioners contend that the Final Rule's requirement for leak-detection equipment with Type C lines is both cost-prohibitive and anomalous in that unodorized transmission lines in Class 1 and Class 2 locations have no such requirement.

PHMSA declines to modify the Final Rule as requested. Simply because transmission lines in Class 1 locations presently need neither odorization nor leak detection equipment when conducting leak surveys does not mean that there are not meaningful public safety and

environmental benefits from requiring Type C gathering lines (which by definition are in Class 1 locations) to employ leak detection equipment.[34] Indeed, PHMSA expects this requirement will promote operators' identification of small leaks before they can develop into a catastrophic failure such as a rupture. And there are environmental benefits from catching even small leaks of gas (which is composed mostly of methane, a potent greenhouse gas) that contribute to climate change. Further, PHMSA understands the efficacy of leakage surveys relying on human senses can be limited. The most conspicuous evidence of a leak detectible by human senses is dead vegetation caused by gas displacing oxygen in the soil. However, it may take a long time for evidence of a gas leak on vegetation to appear from the air, and vegetation surveys yield unreliable results depending on soil and climate conditions, the characteristics of the vegetation, the time of year and other factors. Finally, vegetation surveys are ineffective in areas with no or sparse vegetation (such as paved areas).

As for costs, PHMSA acknowledges that the Final Rule's requirement to use leak detection equipment will entail some compliance costs for affected operators — but those costs will not be as high as suggested by Petitioners. The regulations do not prescribe any particular leak detection equipment; rather, its regulations entrust to operators discretion to identify which leak detection equipment is appropriate for their needs, thereby giving them the ability to manage their compliance burdens. PHMSA understands that a variety of leak detection equipment, at different price points, is available for operators to choose from. PHMSA further understands that most operators will already have access to such equipment in the ordinary course of business for use with their gathering lines or other assets (e.g., production sites, transmission lines). PHMSA therefore concludes that any incremental costs associated with the Final Rule's leak detection equipment requirement will be negligible, and would in any event be justified by the significant safety and environmental benefits anticipated from the use of such equipment.

K. PHMSA Declines to Amend the Final Rule in Response to Miscellaneous Recommendations in the Petition.

The Petition concludes with three miscellaneous requests for revision of the Final Rule for clarity and consistency with other elements of PHMSA's regulatory regime, each of which PHMSA declines to adopt. Petition at 31. PHMSA believes the Final Rule's organization of the Type C substantive requirements in § 192.9 into three distinct subparagraphs is sufficiently clear and notes this approach is consistent with the approach taken in current regulations at § 192.9 defining the substantive requirements governing Types A and B gathering lines. PHMSA also declines to remove the regulatory definition of "building intended for human occupancy" at § 192.9(f)(3) because it has determined that regulatory language is appropriate in the context of Type C gathering lines--notwithstanding any slightly different meaning PHMSA may

[34] PHMSA also notes that data from the U.S. Environmental Protection Agency (EPA) suggests that leaks from gas transmission line pipe occur with less frequency than leaks on gas gathering line pipe. See EPA, "Natural Gas and Petroleum Systems in the GHG Inventory: Additional Information on the 1990-2019 GHG Inventory" (Apr. 2021), https://www.epa.gov/ghgemissions/natural-gas-and-petroleum-systems-ghg-inventory-additional-information-1990-2019-ghg.

employ within implementing guidance for other regulatory contexts such as PHMSA's class location requirements at § 192.5. Finally, PHMSA declines Petitioners' suggestion to extend to Type C gathering lines the "cluster" concept employed in connection with determining the length of class 2 and 3 locations pursuant to 49 CFR 192.5, because PHMSA has determined that regulatory flexibility would be inappropriate in the context of Type C lines located in class 1 locations with lower population densities than class 2 and 3 locations.

III. PHMSA DENIES THE MOTION TO STAY.

Petitioners' Motion does not provide a compelling reason to warrant a stay of certain provisions of the Final Rule as requested by the Petitioners. As Petitioners are aware, PHMSA may grant or deny requests for a stay of its regulations at its discretion. PHMSA has considered Petitioners' stay request by applying the four-factor test that a court would likely apply should Petitioners move for a stay pending judicial review of the Final Rule.

Emergency relief "is an extraordinary remedy never awarded as of right." Winter v. Natural Res. Def. Council, 555 U.S. 7, 24 (2008). It should not be granted unless "the movant, *by a clear showing*, carries the burden of persuasion." Mazurek v. Armstrong, 520 U.S. 968, 972 (1997) (quoting Wright, Miller & Kane, Federal Practice and Procedures § 2948, pp. 129-30 (2d ed. 1995) (emphasis in original)). A court applies the following four-factor test when determining whether to grant a stay of a federal agency's order: (1) whether the applicant has made a strong showing that they are likely to succeed on the merits; (2) whether the applicant will be irreparably injured absent a stay; (3) whether issuance of a stay will substantially injure the other parties interested in the proceeding; and (4) where the public interest lies. Nken v. Holder, 556 U.S. 418, 434 (2009). The last two factors merge when the government is the party opposing a stay. Id. at 435. As explained in further detail below, Petitioners have failed to demonstrate likelihood of success on the merits, irreparable harm absent a stay, or that public interest favors a stay. Therefore, PHMSA denies Petitioners' Motion requesting a stay of certain provisions of the Final Rule.

A. The Petitioners Are Unlikely to Succeed on the Merits.

As explained in detail above and in the enclosed Appendix, Petitioners' procedural arguments are wholly without merit. The Final Rule represents the culmination of a decade-long PHMSA rulemaking effort in which the agency evaluated the risks to public safety and the environment posed by unregulated gathering lines and carefully considered different approaches it could employ to ameliorate those risks (by reference to, among other things, technically feasibility, cost-effectiveness, and practicability). Throughout that process, PHMSA documented its reasoning within written materials (including an ANPRM, an NPRM, and their respective supporting documents) for stakeholder evaluation. PHMSA also provided multiple opportunities for public participation — including solicitations of comment on the ANPRM and the NPRM; the GPAC Meeting; and stakeholder meetings with PHMSA leadership and OMB. Petitioners availed themselves of those opportunities, submitting more than 600 pages of written material in the rulemaking docket, attending numerous meetings with PHMSA and OMB personnel, and actively participating in the June 2019 GPAC Meeting on the rulemaking.

That PHMSA does not agree with all advice provided by Petitioners[35] is not evidence of PHMSA's violation of APA and the Pipeline Safety Act procedural requirements. Rather, PHMSA evaluated the administrative record and reached a different, reasoned conclusion regarding the appropriate balance between costs and benefits in the Final Rule. Whereas the Petitioners contended that there was inadequate information to extend select part 192 safety and part 191 reporting requirements to larger-diameter, currently unregulated gathering lines, PHMSA concluded that record evidence of the potential risks to public safety and the environment warranted those common-sense and limited additional regulatory requirements. PHMSA's professional judgment is supported by the fact that the GPAC's technical experts reached similar conclusions. Petitioners' heavy reliance on the cost estimates in the ICF Study is misplaced because it fails to take into consideration many of the meaningful changes to the requirements adopted in the Final Rule. PHMSA discusses at length above and in the enclosed Appendix the flaws in the ICF Study's analysis, including that document's evaluation of the potential financial impact on small entities.

B. Petitioners Have Not Demonstrated an Irreparable Harm Warranting Stay of Elements of the Final Rule.

Petitioners must demonstrate that absent a stay, they will suffer an injury that is "both certain and great, actual and not theoretical, beyond remediation, and of such imminence that there is a clear and present need for equitable relief." Mexichem Specialty Resins, Inc. v. EPA, 787 F.3d 544, 555 (D.C. Cir. 2015) (quotation omitted). Petitioners have not demonstrated that they or their members will suffer irreparable harm warranting equitable relief from those provisions of the Final Rule identified in the Motion.[36]

Petitioners base their claim of irreparable harm on potential compliance costs for Type C lines (and lines that could be Type C lines) from part 191 reporting and certain near-term part 192 classification requirements, highlighting the description of potential costs on pertinent operators estimated by the ICF Study. Motion at 7. Petitioners also contend that the near-term compliance timelines for the provisions identified in the Motion will increase the costs of compliance with the Final Rule in light of current inflation rates and the supply chain disruptions caused by the ongoing COVID-19 public health emergency. Id. Petitioners further assert that small entities will be hit particularly hard by the Final Rule's compliance costs, as they may not be able to recover compliance costs as easily as rate-regulated pipelines. Id. Petitioners request a stay of those Final Rule requirements during the pendency of PHMSA's review of the Petition. Id. at 8.

[35] As explained in section I.A above, the cost-related concerns of Petitioners and other industry stakeholders were in fact successful in convincing PHMSA to adjust some elements of the rulemaking to reduce compliance burdens.

[36] The Motion requests stay of §§ 191.3 (definitions for part 191), 191.5 (notification of incidents on Type C lines), 191.15(a)(1) (incident reporting for Type C lines), 191.17(a)(1)(annual reporting for Type C lines), 191.23(a)(safety-related condition reports for Type C lines), 192.8(a)(5)(existing incidental gathering lines that are replaced, relocated, or otherwise changed after May 16, 2022), and 192.8(b)(1)(identification of endpoints of Type C gathering lines). Motion at 1 & nn. 3-5. Petitioners also assert the right to seek stay of other, unspecified requirements. Id. at 1 n. 6.

As an initial matter, "economic loss does not, in and of itself, constitute irreparable harm." Wisc. Gas Co. v FERC, 758 F.2d 669, 674 (D.C. Cir. 1985). Further, even accepting Petitioners' contention that there may be increased costs associated with compliance with the Final Rule, the Petitioners must still demonstrate that the economic harm they or their members face are "actual and not theoretical." League of Women Voters of United States v. Newby, 838 F.3d 1, 8 (D.C. Cir. 2016) (quotation omitted). Apart from making bald assertions that pipeline operators will face significant compliance burdens and potentially increased costs to comply with the Final Rule, the Petitioners fail to identify any actual harm to Petitioners or their members absent a stay of the Final Rule. Petitioners provide no information about the specific costs its members will incur to comply with the Final Rule or the impact of such costs on specific operators, nor do they identify with specificity any subsets of operators or particular operators who will be irreparably harmed by the Final Rule. The Petitioners' claims regarding the financial impact on operators merely reference the generic cost estimates in the ICF Report, which, as explained above and in the enclosed Appendix, are not reliable. Petitioners generally assert that inflation and COVID-19-related supply chain disruptions will lead to increased compliance costs, which will have a disproportionate impact on small operators, but without more specific information regarding the alleged harm to Petitioners or their members, PHMSA is left to speculate whether such harms exist and rise to the level of irreparable harm. See Wisc. Gas Co., 758 F.2d at 674 ("Bare allegations of what is likely to occur are of no value since the court must decide whether the harm will *in fact* occur.") (emphasis in original).

Further, the Motion does not explain how the relief requested — a stay pending PHMSA's resolution of the Petition — would prevent the harm they allege, as the stay would merely delay affected operators' investment in compliance efforts rather than eliminate those costs. As explained above in section II, PHMSA has addressed Petitioners' concerns regarding certain provisions for which they have requested a stay by way of either clarification, adjusted regulatory text, or limited enforcement discretion. Finally, since the Final Rule was published in late November 2021, gathering line operators have had the opportunity to review the contents of the Final Rule and either begin efforts to bring themselves into compliance with the Final Rule's requirements or seek an extension of compliance timelines pursuant to the procedural mechanism set forth in 49 CFR § 192.18. To date, PHMSA has not received a single extension request.

C. Public Interest Weighs Against a Stay of the Final Rule.

Public interest weighs against a stay of the Final Rule. This rulemaking responds to Congress's instruction to issue a rulemaking expanding safety and reporting requirements.[37] Further, as explained at length throughout the administrative record, the proliferation of larger-diameter unregulated gathering lines ***already*** poses significant risks to public safety and the environment — any further delay before those unregulated gathering lines are subject to the safety requirements of the Final Rule will only compound and increase those risks. Indeed, insofar as the Petitioners have requested a stay of the Final Rule provision requiring a threshold determination whether a particular gathering line is a Type C or Type R line (§ 192.8(b)(1)), they

[37] See Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020, Pub. L. No. 116-260, § 112(a), 134 Stat. 2210 (2020); 86 FR at 63272-73 (discussing Congressional mandates in connection with this rulemaking).

have effectively requested a stay of most of the Final Rule's requirements.[38] Similarly, any delay in part 191 reporting requirements for Type R lines would frustrate PHMSA's access to information necessary to determine if the risks to public safety and the environment from some or all Type R lines also merit extension of part 192 safety requirements. Apart from citing to the alleged irreparable harm their members would face absent a stay, Petitioners fail to explain how public interest favors a stay of the Final Rule. Therefore, PHMSA finds that public interest weighs against a stay of the Final Rule.

IV. CONCLUSION

PHMSA acknowledges the Petitioners' commitment to safety and environmental protection, as well as the meaningful contributions Petitioners and their members have made to PHMSA's decade-long development of this critically important rulemaking for ensuring public safety and the environment from approximately 400,000 miles of onshore gas gathering lines. PHMSA looks forward to working closely with the Petitioners in the timely implementation of the common-sense and long-overdue safety and reporting requirements within the Final Rule.

Sincerely,

Tristan H. Brown

Tristan H. Brown
Deputy Administrator
Pipeline and Hazardous Materials Safety Administration

[38] PHMSA acknowledges that Petitioners characterize their Motion as being directed at Type C lines; however, whether a line is a Type C or R line turns on the threshold determination required by § 192.8(b)(1) — which the Motion does not (as it does for other Final Rule provisions for which a stay is requested) limit to Type C lines. Compare Motion at 1 n. 4 (limiting stay request of § 191.23(a) as applied to Type C lines) with n. 6 (containing no such explicit limitation for of § 191.8(b)(1), instead asserting that Petitioners "reserve the right to seek a stay of other requirements in the Final Rule, if appropriate, in the future.").

Appendix

This appendix supplements PHMSA's Response to the Petition for Reconsideration ("Petition") of the Final Rule, "Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments" (2137-AF38, the "Final Rule").[1] In this appendix, PHMSA elaborates on the administrative record regarding the cost-benefit analysis supporting the Final Rule by addressing in detail the arguments presented by the Petitioners GPA Midstream and American Petroleum Institute ("API"), particularly as it relates to the Petitioners' reliance on a 2016 report prepared by ICF International (the "ICF Study").[2] The ICF Study was prepared on behalf of co-petitioner API and purports to evaluate the costs and benefits in PHMSA's Notice of Proposed Rulemaking ("NPRM") on the Safety of Gas Transmission and Gathering Pipelines.[3]

Although PHMSA considered the assumptions and methodology of the ICF Study along with other comments, PHMSA was unable to directly use the estimated costs and benefits in its final Regulatory Impact Assessment ("RIA").[4] Of greatest importance, the ICF Study was not updated to factor in changes made to the Final Rule in response to stakeholder comments on the NPRM, and its cost estimates are predicated on flawed methodology and erroneous assumptions.[5] PHMSA made a number of adjustments in the Final Rule and RIA in response to the public comments and recommendations from the Gas Pipeline Advisory Committee ("GPAC") to better focus the NPRM's enhanced safety and reporting requirements on gathering lines posing the greatest risks to public safety and the environment. Additionally, the ICF Study relies on unsupported assumptions that are inconsistent with observed industry trends and misapprehensions regarding the substantive requirements of the Final Rule. PHMSA discusses these issues further below.

The ICF Study has limited utility because it is an assessment of the NPRM, not the Final Rule, and has not been updated since 2016

Petitioners do not acknowledge that PHMSA's changes from the NPRM to the Final Rule significantly reduced the estimated cost of compliance. For example, the NPRM proposed corrosion control, line marker, and leakage survey requirements for all gathering lines greater than or equal to 8.625 inches in outer diameter. Based on PHMSA's updated estimate, the NPRM as proposed would have applied these requirements to approximately 90,863 miles of gathering lines. In the Final Rule, PHMSA took a second look at these (and other) provisions and, after considering the comments to the Final Rule and receiving the recommendations of the GPAC, decided to apply those requirements only to certain pipelines posing the greatest risks to public safety and the environment: gathering lines greater than 16 inches in diameter and gathering lines with pipe diameters greater than or equal to 8.625 inches and up through 16 inches where at least one house is located within the potential impact radius ("PIR"). As a result, the Final Rule applies these requirements to

[1] 86 FR 63266 (Nov. 15, 2021).
[2] ICF International, "Cost and Benefit Impact Analysis of the PHMSA Natural Gas Gathering and Transmission Safety Regulation Proposal" (July 1, 2016).
[3] 81 FR 20722 (Apr. 8, 2016).
[4] Doc. No. PHMSA-2011-0023-0488.
[5] Many of the calculations employed in the ICF Study are opaque, thereby inhibiting evaluation of the ICF methodology. By way of example, a frequent practice within the ICF Study is that it will copy identical tables throughout the document and provide limited or no explanatory text describing the use of some or all the data within those tables in connection with a particular calculation—leaving it to the reader to divine precisely how ICF arrived at the values in its analysis.

approximately 20,336 miles of gathering lines, a fraction of that covered in the NPRM and a difference of more than 70,500 miles of pipe. Petitioners may have ignored the cost impact of these changes out of necessity because the completion of the ICF Study in 2016 limits its utility in assessing a Final Rule that was completed five years later and, as described, included substantial adjustments from the proposed rule stage.

As part of its analysis of the Petition, PHMSA re-assessed the estimated costs of the NPRM by applying the cost model used in the final RIA and updated inputs to the NPRM provisions, which resulted in an estimated annualized cost for the NPRM as proposed of approximately $56.0 million.[6,7] However, when the changes between the NPRM and the Final Rule are factored into that analysis, the annualized cost of Final Rule drops to approximately $13.7 million. Indeed, by limiting the requirements for corrosion control, line markers, and leakage surveys to only those lines that present a higher risk, PHMSA reduced the estimated cost on operators by approximately $42.2 million annually at the 7% discount rate.

The ICF Study's estimate of existing, currently unregulated gas gathering mileage subject to the Final Rule is *lower* than PHMSA's calculation in the RIA

PHMSA's singular focus in the RIA was to accurately assess the costs and benefits of each regulatory provision included in the Final Rule. In contrast, the Petitioners rely on the outdated ICF Study, which suggests that PHMSA's Preliminary RIA ("PRIA") prepared for the NPRM underestimated the number of miles of gas gathering lines in the United States. Based on comments received in response to the NPRM, PHMSA re-assessed its estimates for gas gathering mileage and adjusted its mileage estimates upward for the Final Rule. As a result, PHMSA's estimated mileage is actually higher than the ICF Study (see Table 1 below for comparison).

Table 1

	ICF (miles)*	PHMSA RIA (miles)**
Type A, Area 2/Type C[8]	77,554	90,863
Type R	310,601	335,246
All Gathering Newly Subject to part 191 or 192 requirements (note: neglecting current Types A and B lines)	388,155	426,109
* ICF Study at 11-12 ** RIA at 14		

PHMSA adjusted its mileage numbers *up* from the PRIA such that PHMSA is now predicting *more* affected miles than ICF (by about 17% for Type C gathering lines, and about 10% for all gathering lines subject to the reporting requirements).

[6] Unless otherwise noted, all cost figures are at the 7% discount rate.
[7] For comparison, the cost model used in the PRIA estimated the cost of the proposed rule to be $41.9 million per year when adjusted to 2018 dollars (which is the assessment year used for the Final Rule).
[8] As pointed out in the Response, the Final Rule replaced the NPRM's references to "Type A, Area 2" with "Type C", in response to comments calling for alternative nomenclature for gathering lines that would become newly-subject to part 192 safety requirements.

PHMSA's higher mileage estimates are based on better methodological assessments and more complete information than what is used in the ICF Study.[9] For example, PHMSA employs fewer and superior assumptions than the ICF assumptions identified. ICF identifies a total of 6 elements of its methodology, all of which are proffered without justification or explanation of their embedded assumptions—and all of which coincidentally have the effect of greatly increasing the total number of affected miles.[10] These include indirect steps for estimating mileage that may compound potential errors:

1. Identify the latitude and longitude of all onshore wells producing gas in 2010 and 2015 using the Drilling Info Inc. HPDI database.
2. Use a "Euclidean minimum spanning tree" geographic information system ("GIS") algorithm to create minimum length straight-lines that link all wells within specific geographic areas together to create hypothetical production/gathering systems. Add up the miles of these links by state.
3. Adjust the miles to account for the fact that production/gathering lines do not follow straight lines and that redundant gathering systems sometime serve the same area.
4. Calibrate this adjustment factor of 17% to match the production/gathering line miles report by the Texas Railroad Commission.
5. Separate production system miles from gathering line miles based on assuming a certain number of production line feet associated per well.[11]
6. Add another 2,905 miles of gathering line to connect those GIS-estimated well gathering line networks to gas processing plants.[12]

In contrast, PHMSA's method relied on real world data provided by co-petitioner API in 2012, stating that there were approximately 240,000 miles of unregulated gathering lines, reported by the largest 45 operators, which PHMSA experts estimated to represent 70% of the total.[13] PHMSA then projected an estimate of gathering lines in service today by adjusting the API based estimate using 24-percent growth between 2012 and 2018, which was based on the observed average rate of increase in reported mileage of regulated gathering lines from operators' annual reports since 2012. As a result, PHMSA's estimated mileage better reflects the existing gas gathering infrastructure that is impacted by the Final Rule than those estimates in the ICF Study.

The ICF Study's projections for future buildout of gas gathering pipelines subject to the Final Rule are unreasonable

The projections in the ICF Study are predicated on unsupported assumptions that are inconsistent with observed industry trends and fail to account for the substantive requirements of the Final Rule. ICF assumes the growth of gas gathering mileage subject to the Final Rule to be greater than the 26,734 over the 5 years from 2010 to 2015, such that over a 15-year analysis period there will be 103,941 additional miles of pipe subject to the Final

[9] PHMSA addresses this issue because it is exemplary of the methodology employed by ICF throughout the report, which relies on assumptions that are not supported with meaningful explanation, but which coincidentally contribute to extremely high compliance estimated costs.
[10] ICF Study at 11.
[11] The ICF Study does not give an assumed number of production line feet per well, nor is a method for arriving at the value provided, which would be needed for the analysis to be independently reproduced.
[12] The ICF Study does not specify the method by which the 2,905 miles was calculated.
[13] Letter from Amy Emmert, Policy Advisor, Upstream and Industry Operations, American Petroleum Institute, "Re: Pipeline Safety: Safety of Gas Transmission Pipelines", Doc. No. PHMSA-2011-0023-0115, (Oct. 23, 2012).

Rule, despite growth having decelerated 53% from the growth rate in the previous 5-year period from 2005 to 2010.[14] However, these projections do not withstand scrutiny.

ICF's projections regarding future buildout—which are provided without meaningful elaboration or defense of their embedded assumptions—assume that all types of gas gathering pipelines will be built at a *faster* rate over the next 15 years than in the preceding five years (i.e., that all types of gas gathering line built will *accelerate* over the analysis period).[15] PHMSA's subject matter experts understand that assumption—which is presented without justification—to be dubious given the trends in domestic onshore drilling activity.

Drilling activity gives a measure of new well completion, which will typically require gathering lines to collect natural gas. Some wells are completed primarily for oil extraction, but most wells also produce natural gas, especially in the shale formations being exploited recently onshore in the United States. Drilling activity as measured by the Baker-Hughes weekly rotary rig count[16] was very high from 2011 through 2014, averaging 1,807 rigs. Activity decreased to an, until then, record low in 2015, in response to a crash in the international oil market. After recovering, the onshore rig count averaged 967 from 2018 through 2019. Since then the count has averaged 464 rigs as the activity initially decreased in response to the onset of COVID-19 public health emergency and has been recovering since. As drilling in shale has matured, the ability to identify more productive parts of the formations is expected to result in sufficient natural gas supply with fewer wells and thus fewer new gathering lines. The output is expected to continue in established fields[17] and derive from more efficient drilling techniques[18] so that fewer miles of new gathering lines will be needed to connect to an established gathering network. Finally, broad-based concerns within industry and among State and Federal regulators about greenhouse gas emissions inherent to the natural gas industry are expected to shift some uses of natural gas to alternatives, which would further reduce the demand for new wells and the gathering lines needed to serve them.

Further, even if PHMSA were to assume that ICF's projections of gas gathering pipeline buildout over the analysis period were sound, the use of those projections throughout the document in calculating costs fails to account for distinctions PHMSA adopted in the Final Rule, which govern how different categories of those future gathering lines are classified under PHMSA regulations. Specifically, the ICF Study assumes—as PHMSA had proposed in the NPRM—a one-size-fits-all approach: all future gathering lines with nominal diameter of 8" or greater would be subject to identical part 191 reporting requirements and part 192 safety requirements. ICF's calculated projected costs fail to take into account the changes adopted in the Final Rule—in part in response to comments by GPA Midstream and others regarding the practicability costs of the proposed changes in the NPRM, see 86 FR at 63274-83—discussed above. As a result, ICF's calculated projected costs are unreliably high.

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[14] ICF Study at 15-16 & Table 8. It is unclear how the ICF Study calculated the estimate of 103, 941 miles of additional pipe. PHMSA notes that if ICF were to assume a constant growth of 26,734 miles per five-year period, then it would only result in 80,202 miles of new gas gathering lines over a 15-year analysis.

[15] See id. at Table 8 (projecting each of the 4 categories of gas gathering pipeline listed to increase over the next 15 years at a rate 30% higher than the immediately preceding 5 years).

[16] Baker Hughes, North America Rig Count, https://rigcount.bakerhughes.com/na-rig-count.

[17] E. Allison & B. Mandler, "What Determined the Location of a Well?", American Geosciences Institute (June 1, 2018), https://www.americangeosciences.org/geoscience-currents/what-determines-location-well.

[18] U.S. Energy Information Administration, "Pad drilling and rig mobility lead to more efficient drilling" (Sept. 11, 2012), https://www.eia.gov/todayinenergy/detail.php?id=7910.

PHMSA has examined the potential effects of the flawed assumptions and methodology in the ICF Study as applied to individual requirements in the Final Rule, and the ICF assumptions and methodology would suggest only marginally higher costs than what PHMSA projects in the RIA. In some areas, PHMSA's estimates are higher—but even in the areas where ICF projects higher costs, the difference would be only 0.1% to 36%. In short, the projected costs using ICF's analysis does not nearly approach the $3,170 million per year annualized estimate of the costs for the expansion of gathering regulations that ICF estimated for the NPRM.

The deficiencies in ICF's development and use of projected gas gathering lines is in contrast to the reasonableness of PHMSA's own projections for gas gathering pipeline buildout over the analysis period. PHMSA's RIA projects that future buildout of Type C pipelines will be about 830 miles/year.[19] PHMSA's estimate is consistent with the historical annual buildout (approximately 1070 miles/year) of Type C gathering lines over the last period of the ICF calculations.[20] Given the slowdown in gathering line buildout discussed above at p. 4, PHMSA's projections for growth in gas gathering lines are more reliable than the values employed in the ICF analysis.

While PHMSA does not use buildout numbers in its cost calculations, they are related to construction costs. PHMSA believes that construction costs are minimal because the regulations do not impose requirements that would go beyond the standard practices for pipelines with similar risk profiles (e.g., Type A/B gathering lines or transmission lines). Similarly, the impacts of building new Type R lines would also be minimal. PHMSA recognizes that there might be modest costs associated with Type R lines: 1) in reporting for existing operators, which we already account for as annual reporting costs, 2) in new operators being required to submit annual reports, and 3) the cost of reporting any additional incidents that occur on the new miles. PHMSA expects these costs will be low for either those only reporting additional information on the reports they already submit and/or for those with very small new systems given the relatively little data needed in populating Type R incident and annual reports under the Final Rule (much of which would be available from the construction planning process).[21]

Lastly, the ICF Study attempts to capture buildouts by extending the annual rate of new construction from the five years preceding its 2016 publication over the next 15 years, but does not estimate retirements. An increasing number of gathering lines serve shale gas wells, which deplete more rapidly than conventional gas resources.[22] The rates of well and gathering line retirements will depend on whether future market conditions allow restimulation of the wells and how many miles of the gathering system can be used to serve new wells as older wells are depleted. However, as a bounding exercise PHMSA used the ICF estimate of 106,936 miles over the 20-year analysis, which PHMSA expects is an overestimate of the net addition of gathering lines. In addition to projecting very high growth in new lines, the estimate does not account for retirements. Even if PHMSA were to apply this growth to the unit costs used in the RIA, the annualized costs of the Final Rule

[19] RIA at 15.
[20] See ICF Study at Table 8.
[21] RIA at 25-29.
[22] A vast literature on the estimated ultimate recovery of shale gas wells has developed since the advent of increased natural gas extraction from shale gas deposits. The reason for this literature is that the output rate patterns over the economic lives of shale gas wells are distinctly different from conventional wells in more porous natural gas bearing formations. For example, Guo et.al (Sustainability 2016, 8(10), 973; https://doi.org/10.3390/su8100973) conclude, "[a]s shown in the results section, the first annual year decline rate of production of a shale gas well is around 70% and over the first two years about 80% of the initial production level is lost due to decline, which is far higher than that of conventional natural gas."

would only increase by 7% to $14.7 million per year. PHMSA's conclusion that the Final Rule's anticipated benefits justify its compliance costs would be unchanged even if the ICF mileage estimate were used.

The ICF Study calculation of the number of affected operators neglects consideration of recent industry trends

In the Final Rule, PHMSA's subject matter experts exercised their best professional judgment in concluding that the number of Type C operators newly subject to regulation under the Final Rule would be approximately 370 operators.[23] This is similar to the number of gas gathering line operators currently subject to regulation under part 192 (i.e. those already regulated operating Type A and Type B lines, which was estimated to be 370 for the final RIA). PHMSA additionally estimated that there would be an additional 130 Type R gathering line operators that would be newly-subject only to the annual and incident reporting requirements, resulting in a total estimate of 500 new Types C and R operators subject to the new reporting requirements.[24]

PHMSA's RIA updated the analysis of the number of gas gathering operators from the PRIA to estimate the number of operators affected by provisions of the Final Rule. The PRIA relied on a 2012 survey of API members in which 45 operators reported 240,860 miles of unregulated gas gathering pipeline, 70% of the 344,086 miles that PHMA estimated existed in 2016. The PRIA found that 292 operators would be affected by the provisions of the NPRM, including 25 operators of smaller systems that would be subject to fewer reporting provisions. In response to public comments on the PRIA, PHMSA updated its estimates to increase the number of distinct operators to total 870, including 130 distinct small operators newly-subject only to Type R provisions and approximately 370 distinct operators of Type C gathering lines that are already subject to requirements for Type A and Type B gas gathering pipelines.

PHMSA's estimate of the number of Type C operators is supported by an analysis of regulated gas gathering and transmission pipeline data. PHMSA used the 2020 Annual Report data to determine that there were 253 operators with 11,408 miles of Type A and/or Type B gas gathering pipelines. This includes 165 operators with 9,307 miles of regulated gas gathering pipelines that also operate transmission lines. PHMSA's subject matter experts, employing their best professional judgment in assuming these operators that also operate transmission pipelines are large operators of gas gathering lines, estimated that they would, on average, operate the same proportion of the total Type C gas gathering line miles. Thus, they would operate 74,128 miles of the 90,863 miles estimated to be covered. The remaining 188 Type A and Type B gas gathering pipeline operators were assumed to be smaller such that their remaining lines do not always have enough miles of gathering pipeline to have the same proportion of Type C gas gathering pipeline as they do of Type A and Type B. Thus, these 188 operators would account for 75% of the same proportion, or 12,551 miles of the estimated 90,863 miles of Type C pipeline. The remaining 4,184 miles of Type C pipeline would be operated by operators who have not previously had gas gathering pipelines regulated as Type A or Type B. Assuming the new operators are similar to the small operators who do not operate transmission pipelines, and thus average 11.2 miles per operator ((11,408 miles-9,307 miles)/188 operators), PHMSA subject matter experts noted this results in an estimate of 374 new operators for Type C pipelines. However, this number does not account for operators with multiple operator IDs in the database, so it is an overestimate by an unknown amount. Thus, after analyzing the latest available data, PHMSA decided that 370 operators would be a reasonably conservative number for the

[23] 86 FR at 63292; RIA at 20.
[24] Id.

provisions affecting 90,863 miles of Type C pipeline and (likely even more conservative) for the provisions affecting a smaller subset of the data.

PHMSA used an analogous analysis to estimate the number of operators with Type R gas transmission pipelines. As explained above, PHMSA subject matter experts estimated 165 operators who operate Types A or B gathering lines along with transmission lines within their systems would operate 273,500 miles of the total 335,246 miles of Type R pipelines. The remaining 562 operators of either Types A, B, or C gathering lines without transmission lines (188 Type A and Type B plus 374 Type C) would operate no more than 61,746 miles of Type R gathering lines. PHMSA subject matter experts estimated that 75% of that pipeline mileage would be operated by entities that currently have Types A or B gathering lines to yield 46,309 miles of Type R pipeline that would be operated by entities that can merely extend their reporting regime for Type A, B, or C gathering lines to their newly-designated Type R lines. PHMSA was intentionally conservative, as the portion of Type R mileage operated by entities that currently have Types A or B gathering lines is likely higher than 75%. This leaves 15,436 miles of Type R gathering lines (25%) operated by entities subject to no other part 191 annual and incident reporting requirements.

The operators of Types A and B gathering lines identified in PHMSA's annual report database without transmission lines were estimated to operate an average of 66.8 miles each of Type C lines in the Type C operator calculation above (12,551 miles/188 operators). PHMSA subject matter experts employed best professional knowledge in assuming that this average would also apply to the remaining 15,436 miles of gathering pipeline owned by operators who operate neither Type A, Type B or Type C gas gathering pipelines, then 231 operators would be operating Type R pipelines who do not operate any other part 192-regulated gas gathering pipeline. This is in addition to the 374 operators that are newly subject to Type C and Type R gas gathering pipeline regulations for a total of 606 operators. Again, PHMSA subject matter experts expect this to be an overestimate because it does not account for operators with multiple operator IDs in the database. PHMSA determined the overestimate is appropriate to avoid underestimating costs in the face of uncertainty. This uncertainty arises from unknown affiliations between entities with operator IDs and there is continuing consolidation of gas gathering systems into fewer operations as described below. PHMSA expects this consolidation to be more pronounced for very small Type R only operators because smaller upstream companies often develop projects including gas gathering systems and then, to raise capital for new upstream projects, sell the projects to companies with larger gas gathering portfolios. Thus, after analyzing the latest available data, PHMSA expects that 500 operators is a reasonably conservative number for companies newly required to submit annual reports and incident reports.

In contrast to the 870 unique operators that PHMSA believes will be affected by either the part 192 or part 191 requirements of the Final Rule, ICF estimates 3,597 unique operators throughout the onshore gas gathering system, based on an extrapolation from 1,576 gathering operators reported to a 5-state (TX/LA/NM/OK/KS) database, and 104 operators reporting to PA state regulators.[25] ICF suggests that the 5-state database accounts for affiliate relationships, but is silent regarding whether the data reported to PA accounts for affiliate relationships. The ICF Study asserts that 62% of these gathering line operators have very small onshore gas gathering pipeline systems with less than 10 miles of total pipeline in this category.

[25] See ICF Study at 12-13 and 120 et seq.

The ICF analysis assumes an average of one operator for every 111 miles of pipeline. Applying this criterion to the affected mileage estimates of the Final Rule for Type C lines, we can estimate the numbers of operators under the different provisions (see Table 2 below). The number of operators mostly ranges around the PHMSA estimate of 370 operators, with between 124 and 819 operators estimated for the various Type C provisions. Said another way, applying the one operator per 111 miles criterion used by ICF to the requirements of the Final Rule would, in many cases, actually result in lower cost estimates than those used by PHMSA. For example, the ICF criterion would project that only 183 operators (vs. 370 estimated by PHMSA) would be required to comply with the requirements for corrosion control, line markers, and leakage surveys, which are the most costly provisions in the Final Rule. While the damage prevention and emergency planning requirements would apply to comparatively more operators if the ICF criterion were accurate, the projected annualized costs of those provisions are comparatively minor ($285,011 per year at the 7% discount rate).

Table 2

Rule Component	PHMSA Estimated Mileage*	PHMSA Operator Count (using ICF Criterion)
Corrosion Control	20,336	183
ROW Surveillance	13,760	124
Line Markers	20,336	183
Damage Prevention	90,863	819
Public Awareness	20,336	183
Emergency Plan	90,863	819
Leakage Surveys	20,336	183
Annual Reporting	426,109	3,839
Incident Reporting	426,109	3,839

*See RIA at 15.

Any consistency between the number of gathering line operators estimated in the RIA and the ICF Study breaks down when one considers the costs of incident reporting and annual reporting. ICF estimates regarding the number of unique operators subject to new reporting requirements are in tension with recent industry trends toward accelerating consolidation in the production and midstream sectors of the United States oil and gas industry, as described below. Indeed, PHMSA understands consolidation in the industry to have picked up roughly around the same time as the ICF Study published. PHMSA understands this phenomenon to have been driven in part by the typical ebb and flow commodity prices, as a glut of natural gas supply post-2015 resulted in weak Henry Hub spot prices until late in 2020.[26] The oil and gas industry's typical boom/bust cycle was exacerbated by the COVID-19 public health emergency, which drove crude oil prices to extremely low levels shutting down a major source of natural gas as a byproduct of crude oil extraction and reducing the profit incentive of high prices for natural gas liquids extracted from natural gas wells. Lower natural gas output will result in higher prices and more wells drilled primarily for natural gas. Wells drilled primarily for natural gas are more productive for natural gas than wells extracting natural gas as a byproduct crude oil extraction, thus

[26] See U.S. Energy Information Administration, "Henry Hub Natural Gas Spot Price," https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm (last visited Mar. 15, 2022).

fewer new wells will be drilled to accommodate demand and consequently fewer miles of gas gathering pipeline will be needed to connect wells to users.[27]

These market forces have accelerated consolidation in the production and midstream sectors since the ICF Study was completed. As some of the new fields have matured at the same time as commodity prices plummeted, many of the very small operators have gone out of business or were acquired by other firms. Large operators are acquiring the systems of smaller operators, seeking higher profits from more efficient, consolidated operations. PHMSA expects this recent trend toward consolidation to continue.[28] As an example of this continuing trend, in early 2020, Trace Midstream and Gemini Midstream combined operations consolidating 240 miles of gas gathering pipelines to operate as Trace Midstream. In March 2022, there was a further consolidation when the Williams Companies, Inc., one of the largest pipeline companies in the United States, agreed to acquire these gas gathering pipeline assets from Trace Midstream.[29] As another example of gas gathering consolidation, in March 2022, Silver Hill Energy Partners III LP agreed to purchase 18 miles of gas gathering pipeline operated by Pine Wave Energy Partners LLC. Pine Wave is an example of a company that builds small systems of gas gathering pipelines to serve the exploration and development ventures it specializes in and Silver Hill is an example of a company that purchases these developed projects to combine into larger operations.[30]

While PHMSA disagrees with the ICF operator count, it is instructive to calculate the sensitivity of the cost calculations to ICF's estimate of affected operators stated in Table 2. Applying the operator estimates (within Table 2) based on the ICF criterion to the RIA cost calculation, the net costs of the Final Rule could increase: annualized costs could be $3.4 million per year higher (25%) at $17.1 million per year.[31] In light of the significant public safety and environmental benefits anticipated from the Final Rule, PHMSA's conclusion that the Final Rule's anticipated benefits justify its compliance costs would be unchanged even if the ICF operator count were used.

None of the ICF Study criticisms support reconsideration of the Final Rule

PHMSA has examined each of the criticisms of the PRIA leveled by the ICF Study. None of the criticism merit reconsideration of the Final Rule. Table 3, below, identifies each criticism and analyzes that criticism in the context of the Final Rule.

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[27] See U.S. Energy Information Administration, "In 2020, U.S. natural gas prices were the lowest in decades" (Jan. 7, 2021), https://www.eia.gov/todayinenergy/detail.php?id=46376.

[28] See, e.g., Housley Carr, "Just the Two of Us, Part 2 – Permian Midstreamers Consolidate As Basin Production Rebounds," RBN Energy LLC (Nov. 30, 2021), https://rbnenergy.com/just-the-two-of-us-part-2-permian-midstreamers-consolidate-as-basin-production-rebounds.

[29] Oil & Gas Journal, "Williams to acquire Trace Midstream Haynesville assets" (Mar. 14, 2022), https://www.ogj.com/pipelines-transportation/pipelines/article/14235528/williams-to-acquire-trace-midstream-haynesville-assets.

[30] Pipeline & Gas Journal, "Pine Wave Energy Partners to Sell Haynesville Acreage, Gathering Assets" (Mar. 14, 2022), https://pgjonline.com/news/2022/march/pine-wave-energy-partners-to-sell-haynesville-acreage-gathering-assets.

[31] This calculation assumes 21 hours of labor per operator for annual report fixed costs and 21 hours per operator for each annual report for the 500 operators identified in PHMSA's estimation. The other operators estimated to operate only Type R gas gathering pipeline in Table 2 (2,969 operators out of the total 3,839 operators, including the 370 who report Type A and Type B gas gathering lines and the 500 operators PHMSA estimated who newly report Type C and Type R gas gathering lines) are subject to simplified annual reporting requirements estimated by PHMSA to average 8 hours per operator as fixed costs and 1 hour per operator for each annual report, which typically consists of reporting no change.

Table 3		
Short Description	**Criticism of PRIA in ICF Report**	**PHMSA-discussion of applicability to Final Rule RIA**
Rule interpretation (ICF Study at 15 et seq.)	(a) The PRIA does not account for the up-front time and associated costs to interpret the rule and determine applicability to various pipe segments within each company's system.	PHMSA disagrees with ICF's assumption that each operator would require 500 hours to understand the Final Rule's substantive requirements and the scope of those requirements' application to particular gathering lines. ICF's estimate of 500 hours seems to assume that all operators would require the same amount of time—more than twelve 40-hour weeks—to digest the Final Rule and determine its application. But this one-size fits all approach is inapposite to the Final Rule, which incorporates a number of revisions to the NPRM's proposed requirements that would generally yield significant reductions in the costs to stakeholders of reviewing its contents, specifically: ▪ Only a fraction of the part 192 safety requirements that were proposed by the NPRM were ultimately imposed on all gas gathering line operators in the Final Rule. For example, the corrosion control requirement is limited to only the largest (greater than 16" outer diameter) or pipelines with outer diameters between 8.625" and 16" that are located near a building intended for human occupancy or other impacted site under the Final Rule—not all pipelines with outer diameter of 8.625" or greater as proposed in the NPRM. For example, corrosion control is required on an estimated 20,000 miles in the Final Rule rather than the 90,000 miles under the NPRM, thus many small operators will not operate pipeline subject to many of the new requirements and will require de minimis effort to understand those parts of the Final Rule. ▪ Further, a large portion of the operators affected by the Final Rule are expected to only have Type R gathering lines, whose reporting requirements are relatively straightforward, as the Final Rule provides that they would be able to submit simplified part 191 incident and annual reports. See 86 FR at 63276. The ICF Study did not articulate a basis for its assumption that each operator would require 500 hours to evaluate the Final Rule's substantive requirements and the application of those requirements to gathering lines. No previous PHMSA rule (in its regulatory analysis) or information collection has accounted for anything close to 500 hours of review for comprehension of a PHMSA rulemaking. Further, reasonable estimates of the burden stemming from evaluation of the Final Rule's requirements is included in the RIA. The longstanding practice by PHMSA for regulatory analysis has been to consider review costs as part of the fixed costs of the provisions of a rule rather than a separate effort. For example, the regulatory evaluation of the 2006 Gas Gathering rulemaking that imposed more numerous and comprehensive parts 191 and 192 requirements than those at issue in this rulemaking did not include a separate cost for regulatory evaluation. Further, the ICF Study estimate neglects consideration of potential efficiencies associated with PHMSA and trade association educational resources and outreach, and contractor resources employing off-the-shelf compliance materials that will facilitate operator efforts to digest the Final Rule. The ICF Study also neglects to account for efficiencies from the ability of many operators to extend their pre-existing programs for compliance with Federal/state regulations governing regulated gas gathering and transmission lines, State damage prevention requirements for gathering lines (if applicable) and voluntary information collection. PHMSA explained in its RIA (see p. 16) that it understands these

		efficiencies to be substantial, particularly as PHMSA's 2006 Gas Gathering rulemaking required one-time surveys of gathering lines that could be leveraged by operators to determine whether and how their lines would be subject to the new part 192 safety and part 191 reporting requirements under the immediate rulemaking. PHMSA further notes that although some gathering lines installed since that 2006 Gas Gathering rulemaking may not be able to rely on that earlier effort, PHMSA expects newer lines to have better records regarding the characteristics of those lines for cost-effectively evaluating application of the Final Rule's requirements. PHMSA therefore understands its own estimates within the RIA of the one-time costs for operators to review and determine the application of the Final Rule are more reasonable than that provided by ICF.
Materials testing and verification and MAOP verification (ICF Study at 18 et seq.).	(b) The proposal requires (192.607) all operators verify pipeline material that do not have "reliable, traceable, verifiable, and complete material documentation records" to conduct material testing of their pipe. The PRIA does not calculate the cost of this requirement.	This requirement is not part of this Final Rule.
MAOP determination (ICF Study at 43 et seq.)	(c) The proposal requires (192.619) that all operators determine or verify Maximum Allowable Operating Pressure ("MAOP"). This requirement creates substantial costs for operators who must determine MAOP. Some gathering operators either cannot utilize the five-year look-back period or do not already know MAOP.	ICF's cost estimates rest on a series of assumptions—95% of currently-unregulated pipelines lack MAOP data at all, and 63% of those pipes lack operating data in the previous 5 years that can serve as an alternative to MAOP (see ICF Study at 43)—that are proffered without basis and seem questionable on their face. ICF also assumes that all existing lines it assumes that lack MAOP or historical operational data would need to conduct pressure testing. In addition, ICF assumes that many pipelines will require upgrades to accommodate in-line-inspection tools. ICF then calculated aggregate compliance costs based on per-mile basis. The ICF Study cost estimates are also based on an obsolete understanding of the rulemaking's contents. ICF's cost estimates assume the universal application of MAOP determination requirements (§ 192.619) to all currently-unregulated gathering lines with nominal diameter of 8" or greater as proposed in the NPRM. However, the Final Rule limits the scope of that § 192.619 requirement to a subset of those existing gathering lines—those new and replaced lines with outer diameter greater than 16" or between 12.75" to 16" if near a building intended for human occupancy. See § 192.9(e)-(f). Only Type C onshore gathering line with an outside diameter greater than 12.75 inches would be required to formally calculate MAOP and maintain pertinent records pursuant to § 192.619. PHMSA expects these criteria to apply to approximately 13,760 miles of pipe—compared to 83,636 miles of pipe assumed in the ICF Study. The Final Rule also allows for flexibility for operators to adjust pertinent compliance timelines for the threshold determination at § 192.8 regarding whether a line is a Type C line or not pursuant to § 192.8(b)(2), and the MAOP verification requirements at § 192.619 pursuant to § 192.9(g)(4)(ii). PHMSA concludes that a negligible number of its estimate of the mileage of currently-unregulated gathering lines, whether subject to formal § 192.619 MAOP determination requirements or not, would be unable to determine MAOP because: (1) PHMSA expects that most recently-

		installed gathering pipelines would have necessary records to calculate MAOP; (2) maximum operating pressure is not difficult to measure or calculate; and (3) PHMSA has provided for notification procedure to allow operators subject to the formal § 192.619 MAOP determination procedures who are unable to perform lookback calculations or verify pressure on their system within the regulatory deadline to either request an extension of that deadline (see § 192.9(g)(4)) or request use of an alternative methodology (see § 192.619(c)). Finally, the scope of the MAOP requirements in the Final Rule and the methods for determining MAOP on Type C gathering lines at § 192.619(c) are similar to those in API Recommended Practice 1182, "Construction, Operation, and Maintenance of Large Diameter Rural Gas Gathering Lines," ("API RP 1182"),[32] a widely-followed framework published by Petitioner API. For these reasons, PHMSA expects its estimates reasonably capture the likely compliance costs of affected operators.
MAOP for exceedance incidents (ICF Study at 43 et seq.)	(d) The proposal requires (191.23) operators to report safety-related conditions including the exceedance of MAOP. An operator must know the MAOP to know if this exceedance occurs, which requires the determination of MAOP. This applies to all pipeline, regardless of regulation. The PRIA does not account for this cost.	PHMSA noted in the Final Rule that it is not requiring operators of gathering lines that are not required to establish an MAOP pursuant to §§ 192.9(e)-(f) and 192.619 of the Final Rule to comply with requirements to report MAOP exceedances and other safety-related condition reports. See 86 FR at 63275. PHMSA is clarifying the regulatory language accordingly in a forthcoming Federal Register notice.
Compressor buildings (ICF Study at 65 et seq.)	(e) The proposal requires (192.163) operators to construct compressor buildings under certain standards. The PRIA does not include this cost to build a noncombustible-material building for new compressor stations built in the future that would not have this requirement without the proposal.	This Final Rule requirement applies to new construction of gathering lines greater than or equal to 8.625" in outer diameter—not 2" in diameter as assumed by ICF. The requirement is that any housing be built from non-combustible material. PHMSA understands (based on its subject matter expertise) that compressor station housings are typically constructed of sheet metal, so it is unlikely that an alternative housing of combustible material (e.g., wood) is ever contemplated. The assumption of $70,000 per compressor building in the ICF Study is excessive, as that value appears to correspond to the entire cost of a housing. The ICF projection is 1,815 compressors for new construction over 15 years or 121 compressors per year. Of these compressors, ICF assumed 19% would fall under construction requirements, so that 23 compressor buildings per year would need to meet construction standards imposed by the Final Rule. ICF further assumed that 75% of the buildings would not meet construction standards in the absence of the Final Rule, so that 17 buildings per year would need to be upgraded. While PHMSA disputes the ICF analysis, even if the costs were increased by about $2,500 per housing (to account for potential incremental costs associated with substitution of materials) then the estimated 17 compressor buildings per year requiring upgraded housing would add $0.04 million per year to the $13.7 million per year cost of the rule.

[32] API, "Recommended Practice 1182: Construction, Operation, and Maintenance of Large Diameter Rural Gas Gathering Lines" (Mar. 1, 2020), https://www.api.org/products-and-services/standards/important-standards-announcements/rp1182and80).

		In addition, PHMSA does not expect any cost will be added because wood construction is unlikely to be less expensive than typical metal construction. Further, any incremental costs associated with the Final Rule would be mitigated by the economies associated with operators adopting as standard business practice to build compressor buildings that are compliant with the standards in the Final Rule—particularly when (as here) the materials required by regulation would be the type generally used to address a well-appreciated risk. Any incremental costs uniquely imposed by the rule for compressor buildings, therefore, are expected to be minimal.
Prompt leak repairs (ICF Study at 67 et seq.)	(f) The proposal requires (192.706) operators perform periodic leak surveys and assessments. The PRIA assumes that operators fix all conditions found during surveys. However, some operators may only monitor certain conditions and may not necessarily fix them within a set timeframe. The PRIA does not consider the cost of fixing these monitored conditions. Additionally, the PRIA does not take into account the incremental cost to fix a large number of conditions within an accelerated timeframe.	The ICF Study misapprehends the requirements in the proposed and Final Rule. Section 192.706 does not require operators of all currently unregulated gathering lines to promptly repair all leaks. Rather, only a subset of Type C lines (specifically, those with outer diameters greater than 16", and those with outer diameters between 8.625" and 16" with a nearby building intended for human occupancy) are subject to the hazardous leak repair requirement at § 192.703(c)—not the repair requirements at § 192.706. See § 192.9(e)-(f). These lines must repair hazardous leaks promptly, but may monitor other leaks without prompt repair if no hazard exists. Other gathering lines (specifically, Type R pipelines and those Type C lines with outer diameters between 8.625" and 16" without a nearby building intended for human occupancy) are not subject to leak repair requirements under the Final Rule. For those gathering lines newly-subject to the § 192.703(c) hazardous leak repair requirements, PHMSA expects that hazardous leaks are promptly repaired when identified as a normal business practice in the baseline, rather than being allowed to persist; therefore, this element of the Final Rule would not impose a significant incremental cost on operators. The ICF Study acknowledges that many leaks—presumably hazardous ones—would be fixed by operators in the ordinary course of business. See ICF Study at 111-12. Finally, to the extent that operators would, in the absence of the Final Rule, not promptly repair leaks that are hazardous to public safety and the environment, the compliance costs of the Final Rule become even more compelling.
Above-ground plastic pipe (ICF Study at 78 et seq.)	(g) The proposal requires (192.321) operators of above-ground plastic pipe in operation for greater than two years install such pipeline below ground with a specified minimum cover. The PRIA does not include the cost for re-installing existing plastic pipe below ground.	This requirement applies to new construction and replacements longer than 40 ft on gathering lines with outer diameter greater than or equal to 8.625". The ICF Study estimates that less than 1% of existing plastic pipe gathering lines are located above ground (only 9 miles of the existing system) in non-compliance with the Final Rule, so the incremental cost it estimates is the cost of rectifying the noncompliant existing pipeline. See ICF Study at Table 113. If one were to accept the ICF Study's assumptions regarding incremental costs on existing lines, the effect on annualized costs is minimal: no more than an additional $44,514 per year. However, the ICF Study's calculations neglect consideration of the 40-foot exception provided in the Final Rule to mitigate incremental costs associated with repair/replacement of small pipeline segments on existing Type C lines. See § 192.9(f)(2). In contrast, the ICF Study attributes to the Final Rule 100% of new pipeline costs associated with compliance with the plastic pipeline requirements (see ICF Study at Table 114)—which is inconsistent with the ICF Study (as explained above) assumption that operators have historically built plastic gathering lines of which less than 1% are non-compliant with the Final Rule. The ICF Study does not supply any justification for this material shift in its assumptions.

		If one were to apply to future/new plastic gathering lines the ICF Study assumptions regarding historical construction practices, the annualized incremental costs of the Final Rule remain minimal. Specifically, if one were to apply the ICF Study assumption that a small fraction (0.13% = 9 miles/7,117 miles from ICF Table 113) of new construction of plastic gathering lines each year would be noncompliant with the Final Rule, then the ICF Study predicts 1,796 miles per year of future plastic pipe construction (ICF Table 114, amounting to 120 miles per year). Applying the 0.13% noncompliance rate to the 120 miles per year yields 0.15 miles per year that will need to be upgraded because of the Final Rule. Applying the 12-inch average diameter and $5,000 incremental cost per inch mile assumed in the ICF Study to the 0.15 miles/year yields an estimated $9,085 per year in annualized costs induced by the Final Rule. This $0.009 million per year is a minimal addition to the total $13.7 million-per-year-cost of the Final Rule.
New construction material costs (ICF Study at 83 et seq.)	(h) The proposal requires (192.105) operators to design newly installed pipeline under certain material standards. This might require higher grade steels, thicker walls, or the substitution of steel for plastic and composites. The PRIA does not include the incremental costs for installing higher grade gathering pipe in the future than currently necessary to comply with the proposed design requirements for pipe.	As explained, in the RIA (see p. 22) PHMSA employed best professional judgment in determining that the incremental costs associated with more rigorous design requirements under the Final Rule would be negligible. PHMSA understands that standard industry practice is to install gathering pipeline in new construction that is compliant with pertinent industry standards, which are largely consistent with the standards in the Final Rule. For example, API RP 1182 states: "Type C gathering line systems shall be designed, constructed, and tested in accordance with 49 CFR 192.9(d)(1)."[33] This construction standard is the same as that required by the Final Rule for Type C pipeline. API RP 1182 further specifies that all other rural gas gathering pipeline with an outer diameter greater than 12.75" shall follow specified requirements for materials, design, construction, cover, location and testing in accordance with recognized and generally accepted industry practices. Industry practice is to reduce repair and damage costs, and liability for third party damages by similarly complying closely with Final Rule standards for new Type C construction in the absence of the Final Rule. In contrast, the assumptions employed in the ICF Study—which are advanced without any evidentiary support—are unreasonable. In addition to inflating the projected buildout of future Type C lines discussed above, the ICF Study's assumption that 50% of those lines would be incompatible with the Final Rule is inconsistent with PHMSA's understanding that newer gathering lines are generally built to more rigorous safety standards than may have been employed in the past. The ICF Study also neglects any consideration of the 40-foot exception provided in the Final Rule to mitigate incremental costs associated with repair/replacement of small pipeline segments in existing Type C lines, and any economies of scale associated with substitution of non-compliant pipe with compliant pipe throughout the gas gathering industry. The ICF Study also cites the pressure limits for polyethylene pipe as potentially requiring larger diameter pipe in locations where plastic pipe is needed to handle very corrosive gases. ICF calculates costs on all new construction rather than limiting the costs to the small fraction that would otherwise be plastic and need to operate above 125 psig for sufficient throughput. PHMSA's subject matter experts, employing their best professional judgment, assume that gathering lines built to be reliable for an operator's purposes will comply with the construction requirements except in rare, idiosyncratic circumstances. The added cost of materials for these rare circumstances does not add substantially to the costs of the rule.

[33] The Type C in this API recommended practices standard is defined as rural gas gathering lines with an outside diameter greater than 16", or greater than 12.75" if buildings intended for human occupancy or other impacted sites are within the PIR.

Vault standards (ICF Study at 87 et seq.)	(i) The proposal requires (192.183) operators to construct any installed vaults under certain design requirements. The PRIA does not include the incremental costs to comply with specific structural design requirements for vaults on new gathering lines installed in the future.	PHMSA objects to the ICF Study's contention that 100% of the costs associated with installation of vaults on gas gathering lines can be attributed to the Final Rule. PHMSA subject matter experts confirm that operators typically construct vaults on their gathering and other gas lines to facilitate maintenance and other activities at distances similar to that (every 50 miles) identified in the ICF Study. Further, the design requirements under § 192.183 are standard criteria employed by industry in building a functionally useful vault. The ICF Study does not identify any specific reasons that the Final Rule would require more vaults to be built, much less that those vaults will be more costly than vaults that would be built in the absence to the Final Rule. PHMSA further notes that its criticisms of the ICF projections of future buildout of gas gathering lines discussed above would apply here as well.
MCAs (ICF Study at 90 et seq.)	(j) The proposal requires (192.619 and 192.624) operators to assess newly defined moderate consequence areas (MCA) for MAOP determination and verification. To determine whether a pipeline must comply, an operator must identify MCA areas, if any, using a GIS. The PRIA does not account for the cost to identify	This requirement is not part of this Final Rule.
Leak surveys (ICF Study at 93 et seq.)	(k) The proposal requires (192.706) operators of Type A, Area 2 to perform periodic leak surveys in order to maintain safe operation of a pipeline. The PRIA does not consider this cost.	The incremental costs from the Final Rule's leak survey requirements are discussed in the RIA (see p. 22). PHMSA understands the RIA estimate of those incremental costs to be accurate and in fact more conservative than the estimate of the ICF Study, which neither reflects the scope of the leak detection requirements in the Final Rule nor employs as-conservative assumptions regarding the limited mileage currently employing leak detection practices. ICF's estimates are based on the flawed assumption that all currently-unregulated, existing gathering lines would be subject to leak survey requirements as had been contemplated in the NPRM—about 77,000 miles. However, the Final Rule narrowed the scope of this requirement in response to stakeholder input: only Type C gathering lines with outer diameters greater than 16", or with outer diameters between 8.625" and 16" and a building intended for human occupancy nearby—corresponding to about 20,000 miles of existing Type C lines. Further, PHMSA employed best professional judgment of its subject matter experts in selecting a baseline compliance rate for those lines—25% compliance—which is lower than the ICF Study's (unsupported) assumption of 37% baseline compliance.
Management of change	(l) The proposal requires (192.13) operators to perform a management of change process as well as reestablish records when gathering systems change hands.	This is not a requirement of this Final Rule.

(ICF Study at 95 et seq.)	The PRIA does not consider these costs.	
Corrosion Control (ICF Study at 101 et seq.)	(m) The proposal requires (192.478 and 192.465) operators adhere to internal and external corrosion requirements for operating gathering lines. This requires performing periodic surveys to monitor the condition of an operating pipe to ensure public safety. The PRIA includes a cost for this requirement; however, these costs do not account for all specified requirements. Hence, ICF developed an estimate of additional costs for this requirement.	The ICF Study alleges that PHMSA underestimates the incremental costs of compliance with the Final Rule's corrosion control requirements, specifically those costs associated with use of internal corrosion monitoring equipment, employment of test stations, and completion of external corrosion surveys. However, the ICF Study does not consider adjustments made to the Final Rule in response to stakeholder concerns regarding (among other things) one-time and recurring costs of cathodic protection on previously-unregulated gathering lines. Whereas the NPRM provided that all currently-unregulated gathering lines would be subject to cathodic protection requirements, in the Final Rule PHMSA narrowed the scope of application of its cathodic protection requirements to a subset of those lines: namely, those with outer diameters greater than 16", or with outer diameters between 8.625" and 16" and a building intended for human occupancy nearby. This change brings the total number of existing lines that could be subject to corrosion control requirements under the Final Rule to approximately 20,336 miles of Type C lines (compared to the more than 77,000 miles of existing gathering lines estimated in the ICF Study). The ICF Study uses this inflated mileage number to calculate the cost of performing external corrosion surveys using a 33% scaling factor that is not supported. See ICF Study, Table 155. Further, as explained in the RIA (p. 19), PHMSA subject matter experts determined that about 95% of those affected lines are relatively modern, steel pipelines that already have cathodic protection—including monitoring test stations—installed. In contrast, the ICF Study assumes—consistent with statements by API—much lower baseline compliance (e.g., only 30% of affected lines having required test stations, and only 75% of affected lines having internal corrosion monitoring) and more frequent test stations/monitors than required by PHMSA regulations. The ICF study assumes that 1 external corrosion test station and 5 internal corrosion monitors are required for every mile of pipeline, while there are no explicit spacing requirements in subpart I. See ICF Study, Tables 157 and 158. This assumption is dubious because the external corrosion test stations and internal corrosion monitors should not change under this rule as these are basic safety measures an operator would reasonably take in the normal course of operation to protect the pipeline from sources that cause corrosion. External monitors are likely to be installed at a frequency that addresses external factors, such as damaged or ineffective external coatings, shorted casing, power lines, pipeline crossings, and other structures that can cause interference currents to the pipeline. Internal corrosion monitoring requirements are based upon assessing separate gas input locations (which operators should know the gas quality based upon their business interests and payment) that are only needed when inputs change—gas input changes are unlikely to occur at a rate of five times every mile on gathering lines of these sizes. Given these limitations in the ICF Study, PHMSA believes its cost estimates in the RIA are more accurate. PHMSA's RIA analysis tracks the substantive requirements regarding corrosion control within the Final Rule and not the NPRM, and employs assumptions regarding baseline compliance levels that are consistent with industry submissions to PHMSA. Similarly, the RIA employs cost values for corrosion control programs derived from (inflation-adjusted) estimates supplied by the IPAA in 2006. See RIA at 18.

Extreme weather events (ICF Study at 106 et seq.)	(n) The proposal requires (192.613) operators to conduct an inspection of all onshore pipeline and following an extreme weather event within 72 hours of cessation of the event. ICF considers this to include the cost to develop a process and perform inspection. The PRIA does not consider these costs for gathering lines.	This requirement is not part of this Final Rule.
Backlog of unremedied conditions (ICF Study at 111 et seq.)	(o) The proposal requires (192.711, 192.713) operators to fix all conditions identified during leak surveys and assessments. Operators have historically monitored conditions without necessarily fixing them. Therefore, a backlog of conditions exists that will need repair when the proposed rule comes into effect. The PRIA does not consider the cost to address the backlog of conditions.	This requirement is not part of the Final Rule. Further, consistent with the discussion above, PHMSA assumes that any backlog of conditions consists of minor problems that are not required to be immediately remedied under the Final Rule, while hazardous conditions would have been remedied in the normal course of business and would not be included in any backlog. As explained above, PHMSA assumes that hazardous conditions will continue to be corrected promptly as a normal business practice and is not a new cost imposed by the Final Rule. In addition, to the extent that operators do not promptly repair leaks that are hazardous to public safety and the environment, compliance costs would be justified.
Annual reports (ICF Study at 115 et seq.)	(p) The proposal requires (191.17) operators to complete and submit annual reports for all pipeline to PHMSA. The PRIA provides an estimate of cost to submit these annual reports, but ICF considers these costs underestimated. We include a revision of these costs in our cumulative cost calculations.	PHMSA understands the ICF Study estimates regarding the costs of annual reporting under the Final Rule to be inconsistent with the contents of the Final Rule and otherwise inflated. The ICF Study reflects the NPRM's one-size-fits-all approach extending existing part 191 annual reporting requirements to all unregulated gathering lines—but the Final Rule discarded this approach in response to stakeholder comments. In its place, the Final Rule establishes that the about 90,000 miles of Type C lines established under the Final Rule would have to submit the same annual reports as transmission lines; the remaining about 335,000 miles of Type R lines need only submit a more simplified, new annual report form. See 86 FR at 63276. The ICF Study's calculations regarding the work effort needed for each operator to complete either species of annual reports are facially implausible because the ICF assumption that operators would need a minimum of 150 hours to complete either the traditional annual report Form 7100.2-1 or the simplified form 7100.2-3 is well in excess of the OMB-approved calculations for completion of the gas transmission annual report form (Form 7100.2). In addition, the ICF Study's calculations neglect any efficiencies arising from simplified work effort in succeeding years because much of the information contained in those annual reports will not change. Similarly, the ICF Study's calculation of costs turns on the same calculation of the total number of operators subject to the Final Rule that (as explained above) is itself flawed. ICF's assumption that 50% of

		operators subject to the Final Rule's annual reporting requirements would have no existing reporting program is unlikely; PHMSA subject matter experts exercising best professional judgment understand that few small gathering pipeline systems are expected to be owned by companies with no other assets in the midstream or upstream segments of the oil and gas industries that are themselves subject to Federal or state reporting requirements. In contrast, the RIA's assumptions yield a reasonable assessment of the costs of annual reporting under the Final Rule. The RIA's calculations track the annual reporting requirements specified in the Final Rule, differentiating between Type C lines subject to more extensive annual report requirements and Type R lines that need submit less information in their annual reports. The RIA also employs estimates for the number of affected operators that are more consistent with observed industry trends (discussed above) than the stale (and dubious) data relied on in the ICF Study. And, the RIA employs assumptions regarding the average number of hours that each operator would require to dedicate to completing an annual report—21 hours for annual reports—that are more consistent with previous information collection calculations, although this labor hours per report is expected to overstate the actual time required to complete such reports because Type R reports have more limited information needs. Indeed, as explained further in section II.A. of the Response, the information requested within the Type R annual report forms is not obscure; rather, it is the minimal sort of information—regarding a gathering pipeline's material characteristics—that any responsible business owning assets known to be potentially hazardous would maintain in ordinary course. Lastly, the RIA accounts for the one-time costs associated with submission of initial annual reports as well as efficiencies in generating subsequent reports.
Offshore incidents data (ICF Study at 115 et seq.)	(r) In the PRIA, the pre-regulation occurrence of incidents were estimated incorrectly by taking the offshore incidents from 2001-2005 and applying them to Type A, Area 2. ICF considers onshore incidents from 2001-2005.	The RIA considers only onshore incident data.
Comparable incident data (ICF Study at 122)	(s) In the PRIA, the post-regulation occurrence of incidents were estimated by taking the reported Type B incidents from 2010-2014 and applying them to Type A, Area 2. ICF considers onshore incidents from Type A, Area 1 to be a better estimate for the high stress Type A, Area 2 pipeline.	The final RIA qualitatively analyzes the public safety and environmental benefits of the Final Rule, including the effect of the rule on incident reduction, in response to stakeholder comments questioning the PRIA's attempts to quantify avoided incidents. PHMSA acknowledges that the paucity of historical incident data for gathering lines complicates quantification of incident frequency attributable to the Final Rule, and notes that one of the (qualitative) benefits of the Final Rule is a better understanding of the risks from gathering pipelines because of new incident and annual reporting requirements. Using this qualitative approach, the RIA demonstrates benefits that justify the costs of the Final Rule. Any single incident can result in significant monetized property loss and bodily harm. See RIA, Table 30 (about $ 1 million per historical incident). Any single incident can also be a significant contributor to climate change. See Environmental Assessment. Each of the above risks would be higher for lightly regulated Type C gas gathering lines than the historical values for (currently regulated) Type A gathering lines. Because Type A lines are subject to a panoply of PHMSA regulatory requirements, their incident rates are naturally going to be much lower than Type C lines that are not yet subject to those same requirements.

		Further, PHMSA expects that the incident report data relied on by the ICF Study provides an underestimate of actual incidents because the great majority of gathering lines have not been subject to any reporting requirements. As described in the Final Rule, incidents and releases from lightly regulated gathering lines are increasingly recognized to be a significant safety and environmental risk.
Gas emissions data (ICF Study at 115 et seq.)	(t) Finally in the PRIA, Table 6-8 estimates the gas lost from onshore and offshore incidents. ICF considers onshore, natural gas, Type A and B pipelines for determining gas lost.	The RIA considers only onshore incident data. Reported damages (Table 30) does not include the value of lost gas.