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JOINT POSITION PAPER
submitted by the
AMERICAN PETROLEUM INSTITUTE
and
GPA MIDSTREAM ASSOCIATION
on
"Pipeline Safety: Safety of Gas Gathering Pipelines," RIN 2137-AF38

Notice of Proposed Rulemaking Published by the Pipeline and Hazardous Materials Safety Administration,
U.S. DEPARTMENT OF TRANSPORTATION,
81 Fed. Reg. 20,722 (Apr. 8, 2016)

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RE: Joint Position Paper of the American Petroleum Institute and GPA Midstream Association on "Pipeline Safety: Safety of Gas Gathering Pipelines," RIN 2137-AF38

I. Introduction

The American Petroleum Institute (API)[1] and GPA Midstream Association (GPA)[2] appreciate the opportunity to submit this joint position paper on the Pipeline and Hazardous Material Safety Administration's (PHMSA) proposed changes to the federal safety standards and reporting requirements for gas gathering pipelines.[3] PHMSA proposed those changes in an April 8, 2016 notice of proposed rulemaking (NPRM),[4] and the Gas Pipeline Advisory Committee (GPAC) will

[1] 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.

[2] GPA has served the U.S. energy industry since 1921 and is composed of nearly 100 corporate members that are engaged in the gathering and processing of natural gas into merchantable pipeline gas, commonly referred to in the industry 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% of the NGLs produced in the United States from natural gas processing.

[3] Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, 81 Fed. Reg. 20,722 (Apr. 8, 2016) (NPRM).

[4] On March 24, 2018, PHMSA advised the Gas Pipeline Advisory Committee that the notice of proposed rulemaking would be separated into three separate final rules for the remainder of the rulemaking process, and that one of those final rules would be dedicated exclusively to gas gathering lines.

be meeting on January 8 to 9, 2019, at the U.S. Department of Transportation's (DOT) headquarters in Washington, D.C., to consider the NPRM's gas gathering provisions. The GPAC is a 15-member peer review committee responsible for advising PHMSA "on the technical feasibility, reasonableness, cost-effectiveness, and practicability" of any proposed gas pipeline safety standard.[5] PHMSA is required to provide the GPAC with a risk assessment and other supporting information as part of the rulemaking process.[6]

In anticipation of the GPAC meeting, PHMSA asked API and GPA to submit a joint position paper on the NPRM's gas gathering proposals. API and GPA represent a significant portion of the producers and gatherers that will be affected by this rulemaking proceeding, and our members welcome the opportunity to assist PHMSA in preparing the materials that will be presented to the GPAC.[7]

II. <u>Executive Summary</u>

- *Gas Gathering Definitions.* API and GPA do not support PHMSA's proposal to adopt new definitions for determining if a pipeline is an onshore gas gathering line. The current regulations, which largely incorporate the functional approach established in API Recommended Practice 80, "Guidelines for the Definition of Onshore Gas Gathering Lines," 1st edition, April 2000, (API RP 80), allow operators to accommodate the wide variety of production and gathering operations that occur throughout the United States. PHMSA's proposed definitions are not necessary, would impose an undue burden on producers and gatherers, and do not have adequate technical or legal support. Accordingly, API and GPA urge PHMSA to retain API RP 80 and the definitions in the current regulations without modification.

- *Class 1 Gas Gathering Lines.* API and GPA support PHMSA's proposal to adopt new safety standards for Class 1 gas gathering lines, but only for pipelines that (1) are greater than 16 inches in nominal outside diameter and (2) have a maximum allowable operating pressure (MAOP) that produces a hoop stress of 20 percent or more of specified minimum yield strength (SMYS) for metallic lines or is more than 125 PSIG for non-metallic lines. Pipelines with these operating characteristics represent the new generation of large-diameter, high-pressure gas gathering lines that PHMSA did not foresee in adopting the current risk-based regulations. API and GPA generally support PHMSA's proposal to apply the requirements for Type B gathering lines and emergency plans to regulated Class 1 gas gathering lines, so long as operators can deviate from those requirements if a variance with written technical justification is included in appropriate program documentation. PHMSA should also consider whether other risk-based concepts can be used to reduce or minimize the burden imposed by any new regulations on Class 1 gas gathering lines that meet the nominal outside diameter criteria (greater than 16 inches) and MAOP thresholds.

[5] 49 U.S.C. § 60115(c)(2) (2017).
[6] *Id*, § 60115(c).
[7] API and GPA both previously submitted detailed comments on the NPRM's gas gathering provisions. The joint positions reflected in this paper are generally consistent with those comments, except with respect certain clarifications and modifications. API and GPA expect that PHMSA will consider the information provided in their respective comments and this joint position paper in addressing any changes to the current regulations for onshore gas gathering lines.

- *Gas Gathering Reporting Requirements*. API and GPA support PHMSA's proposal to apply the federal reporting requirements to Class 1 gas gathering lines, but only to a limited extent. Regulated Class 1 gas gathering line operators should only be required to obtain an Operator Identification Number (OPID), file abbreviated annual reports, and submit incident reports. Operators of unregulated Class 1 gas gathering lines should be required to obtain an OPID, file abbreviated annual reports, and submit incident reports for fatalities or injuries involving in-patient hospitalization.

III. **Background**

In the Natural Gas Pipeline Safety Act of 1968 (1968 Act), the U.S. Congress provided DOT with the authority to prescribe minimum federal safety standards for the transportation of gas by pipeline.[8] The 1968 Act defined "transportation of gas" to include "the gathering, transmission, distribution of gas by pipeline or its storage in or affecting interstate or foreign commerce[,]" but specifically excluded "the gathering of gas in those rural locations which lie outside the limits of any incorporated or unincorporated city, town, village, or any other designated residential or commercial area such as a subdivision, a business or shopping center, a community development, or any similar populated area which the Secretary may define as a nonrural area[.]"[9] The legislative history indicates that Congress decided to exclude rural gas gathering lines from DOT's jurisdiction, because the industry's "impressive" safety record did not support the need for federal regulation.[10]

In 1970, DOT established the original minimum federal safety standards for gas pipeline facilities in 49 C.F.R. Part 192.[11] Consistent with the statutory prohibition in the 1968 Act, the original DOT regulations "d[id] not apply the gathering of gas outside of . . . [a]n area within the limits of any incorporated or unincorporated city, town, or village" or "[a]ny designated residential or commercial area such as a subdivision, business or shopping center, or community development."[12] However, gas gathering lines within these populated areas were subject to the requirements that applied to transmission lines.[13] The original DOT regulations also provided a general definition for the term "gathering line".[14] That general definition, which is still codified

[8] Pub. L. No. 90-481, 82 Stat. 720.
[9] *Id.* § 2(3), 82 Stat. at 720.
[10] H.R. Rep. No. 1390 (1968), *reprinted in* 1968 U.S.C.C.A.N. 3223, 3234-35. ("There is no question that there exist certain gathering lines which are located in populous areas but the tremendous bulk of such lines is located in rural areas. Testimony was offered as to the safety record of these lines and that no man-days had been lost as a result of accidents on gathering lines during the past 6 years. The safety record is impressive.").
[11] Establishment of Minimum Standards, 35 Fed. Reg. 13,248, 13,258-59 (Aug. 19, 1970). Two years earlier, in a November 1968 final rule, PHMSA adopted the provisions in the B31.8-1968 to serve as its interim federal safety standards for gas pipeline facilities. Part 190—Interim Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline, 33 Fed. Reg. 16,500, 16,500-16,503 (Nov. 13, 1968). The 1970 final rule established the original version of Part 192, which contained the first set of permanent federal safety standards for gas pipeline facilities.
[12] Establishment of Minimum Standards, 35 Fed. Reg. at 13,258
[13] *Id.* at 13,259.
[14] *Id.* at 13,258.

in the current regulations, provides that a gathering line is "a pipeline that transports gas from a current production facility to a transmission line or main."[15]

More than two decades later, Congress amended the federal pipeline safety laws to provide DOT with additional authority to regulate rural gas gathering lines.[16] Specifically, the Pipeline Safety Act of 1992 (1992 Act) directed DOT to create a new regulatory definition for the term "gathering line" within two years after considering the "functional and operational characteristics" of gas gathering lines and without regard to any classification used by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act.[17] The 1992 Act also directed DOT to issue regulations within three years establishing minimum federal safety standards for a subset of so-called "regulated gathering line[s]."[18] In deciding on "the types of the lines which are functionally gathering but which, due to specific physical characteristics, warrant regulation[,]" the 1992 Act required DOT to "consider such factors as location, length of line from the well site, operating pressure, throughput, and the composition of the transported gas."[19]

In 1999, API launched an effort to create a new recommended practice for defining onshore gas gathering operations. That effort, led by an industry coalition representing nearly two dozen oil and gas and pipeline trade organizations, culminated with the publication of API RP 80 in April 2000. To accommodate the wide variety of operations that occur throughout the United States, the coalition that drafted API RP 80 used two core principles to differentiate between production and gathering operations: (1) function and (2) the furthermost downstream concept. The coalition considered and rejected several other factors in adopting these core principles, including physical parameters (size, length, operating pressure), gas quality, gas throughput, custody transfer, geopolitical boundaries, and other regulatory designations.

In March 2006, PHMSA concluded a lengthy rulemaking process by adopting the current regulations for onshore gas gathering lines.[20] Those regulations require operators to follow API RP 80 in determining if a pipeline meets the definition of an "onshore gathering line," subject to certain additional limitations to prevent.[21] The regulations apply two categories of onshore gas gathering lines: (1) Type A gathering lines, which include metallic lines with an MAOP of 20

[15] *Id.*; 49 C.F.R. § 192.3 (2017). In 1974, DOT initiated a rulemaking proceeding that sought to clarify the original gathering line definition. Transportation of Natural and Other Gas by Pipeline; Definition of a Gathering Line, 39 Fed. Reg. 34,569, 34,570 (Sept. 26, 1974). DOT terminated that proceeding four years later without changing the definition in response to strong opposition to the proposal. Transportation of Natural and Other Gas by Pipeline; Definition of a Gathering Line, 43 Fed. Reg. 42,773 (Sept. 21, 1978).

[16] Pub. L. No. 102-508, § 109(b), 106 Stat. 3289, 3295 (codified at 49 U.S.C. § 60101(b)).

[17] *Id.*

[18] *Id.*

[19] *Id.* Four years later, in the Accountable Pipeline Safety and Partnership Act of 1996 (1996 Act), Congress further amended the federal pipeline safety laws to provide DOT with the authority 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." Pub. L. No. 104-304, § 12, 110 Stat. 3793, 3802 (codified at 49 U.S.C. § 60117(b)).

[20] Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 Fed. Reg. 13,289 (Mar. 15, 2006) (codified at 49 C.F.R. §§ 192.8 to 192.9) (Gathering Line Definition). A gathering line is generally defined in Part 192 as a "pipeline that transports gas from a current production facility to a transmission line or main." 49 C.F.R. § 192.3.

[21] 49 C.F.R. § 192.8(a).

percent or more of SMYS, as well as nonmetallic lines with an MAOP of more than 125 PSIG, in a Class 2, 3, or 4 location;[22] and (2) Type B gathering lines, which include metallic lines with an MAOP of less than 20 percent of SMYS, as well as nonmetallic lines with an MAOP of 125 PSIG or less, in a Class 2 location (as determined under one of three formulas) or in a Class 3 or Class 4 location.[23] Operators of Type A and Type B lines must comply with certain gas transmission line regulations and the federal reporting requirements, except for the National Pipeline Mapping System (NPMS) provisions. PHMSA's pipeline safety standards and reporting requirements do not currently apply to Class 1 gas gathering lines.

In April 2016, PHMSA published an NPRM proposing extensive changes to the regulations for gas gathering lines. Specifically, PHMSA proposed to (1) repeal API RP 80 and adopt a series of new definitions for determining whether a pipeline is an onshore gas gathering line; (2) apply certain pipeline safety standards to Class 1 gas gathering lines; (3) modify the safety standards that apply to Type A gathering lines; and (4) apply the reporting requirements to operators of all gathering lines, whether regulated or not.[24] 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.[25] PHMSA also asserted that its proposals were consistent with a 2010 National Association of Pipeline Safety Representatives (NAPSR) resolution and more recent U.S. Government Accountability Office (GAO) recommendations relating to gas gathering lines.[26]

API, GPA, and other industry stakeholders submitted comments responding to the NPRM's gas gathering provisions. The industry commenters generally indicated that PHMSA's proposals would undermine the risk-based structure of the current regulations and have a significant adverse impact on producers and gatherers by extending PHMSA jurisdiction closer to the wellhead, requiring the widespread reclassification of pipeline facilities, and imposing unduly burdensome regulations and reporting requirements. The industry commenters also indicated that PHMSA's Preliminary Regulatory Impact Analysis (PRIA) significantly underestimated the costs—and significantly overestimated the benefits—of the gas gathering proposals. While the PRIA estimated that the costs would exceed the benefits by approximately $1 million over the initial 15-year compliance period, an independent economic analysis submitted by API showed that the costs would exceed the benefits by more than $28 billion over that same period. API's independent economic analysis further found that the NPRM would have a disproportionate economic impact on small operators, leading to annual compliance costs that would consume about 90% of the revenue generated by small gathering companies.

[22] *Id.* 192.8(b) (table)
[23] *Id.*
[24] NPRM at 20,827-20,828.
[25] *Id.* at 20,801-20,808.
[26] *Id.* at 20,808; Preliminary Regulatory Impact Analysis at 101 (Mar. 2016) (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); 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).

IV. Joint Position on Gas Gathering Proposals

A. Gas Gathering Definitions

Current Rules: Operators use API RP 80 to determine if a pipeline is an onshore gas gathering line, subject to certain additional regulatory limitations.

PHMSA Proposal: Repeal API RP 80 and add new definitions for determining whether a pipeline is an onshore gas gathering line.

API-GPA Position: Retain API RP 80 and make no other changes to the definitions in the current regulations.

1. *Current Rules*

Operators are currently required to use API RP 80 to determine the extent of production and gathering operations, subject to certain additional regulatory limitations.[27] API RP 80 defines a production operation as "piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids[.]"[28] A production operation also "includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply[,]"[29] as well as "individual well flowlines, equipment piping, transfer lines between production operation equipment elements and sites, and tie-in lines to connect to gathering, transmission, or distribution lines."[30] Part 192 prohibits certain dual-use equipment from being classified as part of a production

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[27] 49 C.F.R. § 192.8(a).

[28] API RP 80 § 2.3. PHMSA does not have the authority to regulate production facilities or operations. *See* 49 U.S.C. § 60101(a)(21)(A); 49 C.F.R. §§ 192.8 and 192.9; Letter from Cesar DeLeon, Dir., Regulatory Programs Office of Pipeline Safety to Mr. Edward M. Steele, Supervisor, Gas Pipeline Safety Section, The Public Utilities Comm'n of Ohio at 1, PHMSA PI-92-010 (Mar. 12, 1992) ("Part 192 does not apply to production facilities"); Letter from Cesar DeLeon, Dir., Regulatory Programs Office of Pipeline Safety to Mr. Lance Fellhoalter, engineering Technician, OXY USA, Inc. at 1, PHMSA PI-93-060 (Oct. 8, 1993) ("The regulations in Parts 40, 191, 192, and 199 apply to pipeline facilities used in the transportation of gas beginning at the end of the production process.").

[29] API RP 80 § 2.3. Section 2.4 of API RP 80 provides a list of supplemental definitions for the terms used in defining a "production operation." The terms covered in Section 2.4 include: (1) "Extraction and recovery," which is defined as "operations used to move liquid and/or gas products from their resident place in the underground reservoir to the surface and separate them into their individual components." (2) "Separation," which is defined as "[t]he physical and/or chemical technique used to segregate produced well fluids (oil, water, gas), e.g., separator vessels, heater treaters, emulsion treaters, free water knockouts, chemelectric units, etc." (3) "Treatment," which is defined as "[t]he physical and/or chemical technique used to enhance separation of produced well fluids and removal of impurities (e.g., water, solids, basic sediment and water, sulfur compounds, carbon dioxide, etc.)[,] . . . includ[ing] iron sponge units, field amine units, and dehydrators." (4) "Stabilization," which is defined as "[t]he treatment of produced fluids during which some gas may evolve" and where "[t]he gas is removed to make liquid product(s) less volatile." (5) "Production compression," which is defined as "[c]ompression situated within the production field and used to (A) enhance production through reduced backpressure on the wells, gas lift, and/or gas injection, and/or (B) boost produced gas pressure to enhance delivery into a gas gathering line."

[30] API RP 80 § 2.4.4(a).

operation.[31] Specifically, "equipment that can be used in either production or transportation, such as separators or dehydrators" is not part of a production operation "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.'"[32]

API RP 80 defines an onshore gas gathering line as "any pipeline or part of a connected series of pipelines" that "transport[s] gas from the furthermost downstream point in a production operation to the furthermost downstream" point in one of the following five locations:

- *Gas Processing Plant*. "[T]he inlet of the furthermost downstream natural gas processing plant, other than a natural gas processing plant located on a transmission line."
- *Gas Treatment Facility*. "[T]he outlet of the furthermost downstream gathering line gas treatment facility."
- *Point of Commingling*. "[T]he furthermost downstream point where gas produced in the same production field or separate production fields is commingled."
- *Compressor Station*. "[T]he outlet of the furthermost downstream compressor station used to lower gathering line operating pressure to facilitate deliveries into the pipeline from production operations or to increase gathering line pressure for delivery to another pipeline."
- *Incidental Gathering*. "[T]he connection to another pipeline downstream of" these endpoints or the furthermost production operation.[33]

Fuel gas return lines are also classified as gathering lines under API RP 80.[34]

PHMSA has imposed three additional regulatory limitations on API RP 80's definition of a gathering line to prevent misapplication of the furthermost downstream concept:[35]

- *Gas Processing Plant*. "The endpoint of gathering . . . 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."[36]

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[31] 49 C.F.R. § 192.8(a)(1).

[32] *Id.* PHMSA has said that this restriction for dual-use equipment "is intended to establish the end of production operations and the beginning of gathering operations at the point where gas transitions to single phase flow regardless of whether or not the gas meets the gas quality requirements of the transmission line." PHMSA, Onshore Gas Gathering FAQs at 16b, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/about-phmsa/grants/pipeline/57056/gathering-faqs-7112007.pdf (last visited Nov. 27, 2018).

[33] API RP 80 § 2.2(a)(1) (emphasis added). Note that a gathering line "may have intermediate deliveries (to other production operations, pipeline facilities, farm taps, or residential/commercial/industrial end users) that are not necessarily part of the gathering line." *Id.* Also note that natural gas processing plants are excluded from API RP 80's gathering line definition. *Id.* § 2,2(b).

[34] API RP 80 states that a pipeline is a gathering line if it is "transport[ing] gas from a point other than in a production operation exclusively to points in or adjacent to one or more production operations or gathering facility sites for use as fuel, gas lift, or gas injection gas within those operations[.]" API RP 80 § 2.2(a)(2).

[35] 49 C.F.R. § 192.8(a)(2)-(4).

[36] *Id.* § 192.8(a)(2) (emphasis added).

In adopting this limitation, PHMSA stated "many of our prior interpretations have based the end of gathering on the first downstream processing plant."[37]

- *Point of Commingling*. "If the endpoint of gathering . . . 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."[38]
- *Compressor Station*. "The endpoint of gathering . . . may not extend beyond the furthermost downstream compressor used to increase gathering line pressure for delivery to another pipeline."[39]

Incidental gathering is a recognized designation under the current rules.[40] "PHMSA considers 'incidental gathering' to include only lines that directly connect a transmission line to one of the [other] endpoints . . . [in section 2.2(a)(1) of API RP 80], as limited by [49 C.F.R. § 192.8]. Lines that connect a transmission line to one of these endpoints by way of another facility are not considered 'incidental gathering.'"[41]

2. PHMSA's Proposal

In the NPRM, PHMSA proposed to repeal API RP 80 and establish new definitions for determining whether a pipeline qualifies as an onshore gas gathering line.[42] Two new terms and definitions would primarily be used for that purpose: (1) "Onshore production facility or onshore production operation" and (2) "Gathering line (Onshore)".[43] Supplemental definitions for "Gas processing plant" and "Gas treatment facility" would also play a role in determining the endpoint of gathering operations.[44] While not acknowledged in the NPRM or considered in the PRIA, PHMSA's proposed definitions are not consistent with API RP 80 and would change the classification of many pipeline facilities from production to gathering, or from gathering to transmission or distribution.

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[37] Gas Gathering Line Definition, 71 Fed. Reg. at 13,295.
[38] 49 C.F.R. § 192.8(a)(3).
[39] *Id.* § 192.8(a)(4).
[40] Letter to Mr. Greg Schrab, CDX Gas, PHMSA PI-09-0002 at 2 (Jul. 14, 2009) (stating that "incidental gathering [line] designations are currently permissible due to [a] drafting error") (CDX Gas Interpretation); Letter to Mr. Leo M. Haynos, Kansas Corp. Comm'n, PHMSA PI-09-0008 at 4 (Jul. 30, 2009) (stating that "incidental gathering designations are currently permissible due to [a] drafting error") (KCC Interpretation). Contrary to the statements made in these letters of interpretation, API and GPA do not agree that PHMSA's decision to recognize the incidental gathering designation is the product of a drafting error. The rulemaking history clearly shows that PHMSA intended to allow operators to use the incidental gathering provisions in API RP 80. Gas Gathering Line Definition 71 Fed. Reg. at 13,292.
[41] Gas Gathering Line Definition 71 Fed. Reg. at 13,292.
[42] NPRM at 20,801-20,808.
[43] NPRM at 20,825-826.
[44] *Id.* at 20,825. PHMSA's proposal required operators of existing pipeline systems to establish the beginning and endpoints of each gathering line using these new definitions within six months and maintain records documenting the results of that evaluation. *Id.* at 20,827. Operators of new gathering lines would be required to make the same determination before the line is placed into service and to maintain records documenting the results of that evaluation. *Id.* As API and GPA indicated in their respective comments, the six-month deadline proposed in the NPRM for reclassifying all existing gas gathering lines is unreasonable even if PHMSA had an adequate legal basis for adopting the new definitions. Comments of API at 49-51 (July 7, 2016); Comments of GPA Midstream at 21-22 (July 7, 2016)

In providing a justification for the new definitions, PHMSA stated in the NPRM that the current rules are "difficult for operators to apply consistently to complex gathering system configurations[,]" and that "[e]nforcement of the current requirements has been hampered by the conflicting and ambiguous language of API RP 80, a complex standard that can produce multiple classifications for the same pipeline system[.]"[45] PHMSA also stated that it had "identified a regulatory gap that permits the potential misapplication of [API RP 80's] incidental gathering line designation . . ."[46] PHMSA stated that the agency and NAPSR had voiced some of these concerns about API RP 80 before adopting the current regulations, and that PHMSA advised pipeline operators in recent letters of interpretation of its desire to clarify the application of the incidental gathering line designation.[47]

3. *API-GPA Position*

API and GPA do not support PHMSA's proposal to repeal API RP 80 and establish new definitions for determining the extent of production and gathering operations. Like other federal agencies, PHMSA is generally required "to use voluntary consensus standards and design specifications developed by voluntary consensus standard bodies instead of government-developed voluntary technical standards when applicable."[48] A broad coalition of interested parties developed API RP 80 using the same American National Standards Institute procedures that apply in developing all other API standards. API reaffirmed API RP 80 in 2013 and is in the process of developing a new edition of the standard. API RP 80 satisfies all relevant procedural and legal requirements to remain incorporated in PHMSA's regulations.

Contrary to PHMSA's statements in the NPRM, operators have not experienced any difficulty in applying API RP 80. API RP 80 is designed to accommodate the wide variety of oil and gas operations that occur throughout the United States, and the emphasis on function and use of the furthermost downstream concept provides operators with the flexibility necessary to distinguish between production and gathering operations in complex configurations. Numerous industry commenters expressed their continued support for API RP 80 in this proceeding, and many of those stakeholders are participating in API's ongoing effort to develop a new edition of that standard.

PHMSA's criticism of API RP 80 as conflicting, ambiguous, or overly complex is misplaced. The integrity management (IM) regulations for gas transmission lines contain more than two dozen sub-sections, incorporate the provisions in another industry standard by reference, and cross-reference a separate guidance document.[49] The IM regulations are far more complex and challenging to apply than API RP 80. There is also no support for PHMSA's claim that API RP 80 cannot be effectively enforced. The NPRM and PRIA do not identify any proceedings that substantiate PHMSA's alleged difficulties in enforcing the current rules, and the record does not

[45] NPRM at 20,801.
[46] *Id.* at 20,807.
[47] *Id.* at 20,803, 20,807.
[48] Pipeline Safety: Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Amendments, 80 Fed. Reg. 168, 177 (Jan. 5, 2015); 15 U.S.C. § 272 note; OMB Circular A-119; Federal Participation in the Development and Use of Voluntary Consensus Standards and in Conformity Assessment Activities, 63 Fed. Reg. 8,546 (Feb. 19, 1998) (final revision of OMB Circular A-119).
[49] 49 C.F.R. Part 192, Subpart O.

indicate that the state authorities generally responsible for regulating production and gathering operations are failing to ensure public safety.[50]

The use of the incidental gathering line designation is neither a misapplication of API RP 80 nor inconsistent with the current rules. API RP 80 appropriately recognizes that incidental gathering lines are a continuation of the gathering process, and PHMSA acknowledged that the current regulations permit the use of that designation in the March 2006 final rule.[51] Any concerns about the regulatory status of incidental gathering lines can be addressed by applying appropriate safety standards to large-diameter, high-pressure gathering pipelines in Class 1 locations.

PHMSA's proposed definitions do not satisfy the rulemaking requirements in the Pipeline Safety Act.[52] In prescribing a new definition for the term "gathering line," the statute requires PHMSA to "consider functional and operational characteristics of the lines to be included in the definition".[53] PHMSA must also consider certain generally-applicable factors in establishing any new pipeline safety standard, including the available relevant gas pipeline safety information, the reasonableness, appropriateness, and reasonably identifiable or estimated costs and benefits of a proposed standard, and the comments and information received from the public.[54] There is no indication in the NPRM or PRIA that PHMSA even considered these statutory requirements in developing the proposed gathering definitions.

Nor do the proposed definitions meet the Pipeline Safety Act's cost-benefit provision. PHMSA assumed in the PRIA that the NPRM's gathering definitions are consistent with the current rules and would impose no additional cost on the midstream industry.[55] The text of the current regulations, and the comments submitted in this proceeding, directly contradict that assumption. PHMSA's proposed definitions would end the production function at a point much closer to the wellhead than API RP 80.[56] PHMSA's proposed definitions would also impose restrictions on the use of the incidental gathering line classification that are not recognized in API RP 80 or the current rules, requiring operators to reclassify many gathering lines as transmission or distribution lines.[57] PHMSA did not consider the significant economic impact that these changes would have on producers and gatherers in the PRIA.

[50] In fact, many of the safety standards administered by state authorities that do not have a certification to participate in the pipeline safety program would be preempted if PHMSA adopts the definitions proposed in the NPRM. 49 U.S.C. § 60104(c); *Olympic Pipeline Co. v. City of Seattle*, 437 F.3d 872 (9th Cir. 2006).

[51] Gas Gathering Line Definition, 71 Fed. Reg. at 13,292, and the Agency affirmed that position in subsequent letters of interpretation. CDX Gas Interpretation, PHMSA PI-09-0002; KCC Interpretation, PHMSA PI-09-0008.

[52] 49 U.S.C. §§ 60101(b); 60102(b)(2).

[53] 49 U.S.C. § 60101(b)(1)(B)(i).

[54] 49 U.S.C. § 60102(b)(2).

[55] PRIA at 100.

[56] The NPRM would end production operations at the point where "[m]easurement for the purposes of calculating minerals severance occurs; or there is commingling of the flow stream from two or more wells[,]" whichever is furthermost downstream. NPRM at 20,826. API RP 80 recognizes that "[t]he production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation." API RP 80 § 2.3.1.1.

[57] Gas Gathering Line Definition, 71 Fed. Reg. at 13,292, and the Agency affirmed that position in subsequent letters of interpretation. CDX Gas Interpretation, PHMSA PI-09-0002; KCC Interpretation, PHMSA PI-09-0008.

For these reasons, API and GPA do not support PHMSA's proposal to repeal API RP 80 and establish new definitions for determining the extent of production and gathering operations. The current regulations allow operators to effectively classify the wide variety of operations that occur throughout the United States, and the record does not provide an adequate legal or technical basis for adopting the changes proposed in the NPRM. Accordingly, PHMSA should retain API RP 80 and the current regulations without further modification.

B. Class 1 Gas Gathering Lines

Current Rules: PHMSA's regulations only apply to regulated onshore gas gathering lines (Type A and Type B) in Class 2, 3, or 4 locations. Gas gathering lines in Class 1 locations are not regulated.

PHMSA Proposal: Regulate Class 1 gas gathering lines that are 8 inches or more in nominal outside diameter with an MAOP that produces a hoop stress of 20 percent or more of SMYS (metallic lines) or is more than 125 PSIG (non-metallic lines) as Type A, Area 2 lines. Operators of Type A, Area 2 lines must comply with the regulations for Type B gathering lines and implement emergency plans.

API-GPA Position: Regulate Class 1 gas gathering lines that are greater than 16 inches in nominal outside diameter with an MAOP that either produces a hoop stress of 20 percent or more of SMYS (metallic lines) or is more than 125 PSIG (non-metallic lines) as Type C lines. Operators of Type C lines should comply with the regulations for Type B gathering lines and implement emergency plans, unless a variance with written technical justification is included in appropriate documentation. Consider whether other risk-based concepts can be used to reduce or minimize the burden imposed by any new regulations.

1. *Current Rules*

If a pipeline meets the definition of an onshore gas gathering line, the regulations require an operator to determine if the line qualifies as a regulated onshore gathering line.[58] Part 192 currently recognizes two categories of regulated onshore gathering lines:

- *Type A Gathering Lines*. Type A gathering lines are defined by regulation to include metallic lines with an MAOP of 20 percent or more of SMYS, as well as nonmetallic lines with an MAOP of more than 125 PSIG, in a Class 2, 3, or 4 location.[59] Operators of Type A lines must comply with all of the requirements for transmission lines, except for the provisions that require accommodation of smart pigs in new and replaced lines

[58] 49 C.F.R. § 192.8(b) (table).
[59] *Id.*

and the gas IM requirements; they are also permitted to use an alternative process for complying with the operator qualification requirements.[60]

- *Type B Gathering Lines*. Type B gathering lines are defined by regulation to include metallic lines with an MAOP of less than 20 percent of SMYS, as well as nonmetallic lines with an MAOP of 125 PSIG or less, in a Class 2 location (as determined under one of three formulas) or in a Class 3 or Class 4 location.[61] Operators of any new or substantially changed Type B line must comply with the design, installation, construction, and initial testing and inspection requirements for transmission lines and, if the line is of metallic construction, the corrosion control requirements for transmission lines.[62] Operators must include Type B lines in their damage prevention and public education programs; establish the MAOP of these lines under § 192.619; comply with the line marker requirements for transmission lines; and conduct leak surveys and promptly repair hazardous leaks.[63]

PHMSA's regulations do not currently apply to gas gathering lines in Class 1 locations. A Class 1 location is "an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1- mile (1.6 kilometers) length of pipeline . . . that has 10 or fewer buildings intended for human occupancy."[64]

2. PHMSA's Proposal

In the NPRM, PHMSA proposed to regulate certain gas gathering lines in Class 1 locations.[65] Specifically, PHMSA proposed to regulate Class 1 gas gathering lines that (1) are 8 inches or greater in nominal outside diameter and (2) have an MAOP of 20 percent or more of SMYS for metallic lines or more than 125 PSIG for non-metallic pipe.[66] Operators of these lines, which are designated as Type A, Area 2 gathering lines in the NPRM, would need to comply with the requirements that currently apply to Type B regulated gathering lines (damage prevention program, corrosion control (for metallic piping), public awareness and education program, MAOP, line marker, and leak surveys), as well as the emergency response plan requirements in Part 192.[67]

The proposal in the NRPM gives operators 6 months to determine if existing gathering lines meet the new Type A, Area 2 criteria and document the results of that evaluation.[68] Operators of existing Type A, Area 2 lines would need to achieve compliance with the proposed safety standards within 2 years (unless an operator is able to justify otherwise and obtain PHMSA approval).[69] Operators of newly installed Type A, Area 2 lines, or existing lines that are replaced, relocated, or otherwise

[60] *Id.* § 192.9(c),
[61] *Id.* § 192.8(b) (table).
[62] *Id.* § 192.9(d)(1) and (2).
[63] *Id.* § 192.9(d)(3)-(7).
[64] 49 C.F.R. § 192.5(a)(1) - (b)(1).
[65] NPRM at 20,827-20,828.
[66] *Id.* at 20,827.
[67] *Id.* at 20,827-20,828.
[68] *Id.* at 20,827.
[69] *Id.* at 20,828.

changed, would also need to comply with the design, construction, and testing requirements in Part 192.[70]

In justifying these proposed changes, PHMSA pointed to recent developments in the field of natural gas exploration and production.[71] PHMSA said in the NPRM that operators are constructing shale gas gathering lines that far exceed historical operating parameters, particularly from a pressure and diameter perspective.[72] PHMSA said that the agency did not foresee or consider the risks associated with these kinds of gathering line systems in developing the March 2006 final rule, and that recent GAO recommendations provide further support for the proposed regulations.[73] PHMSA also noted in the PRIA that the outside diameter and MAOP criteria used to delineate Type A, Area 2 gathering lines are consistent with a 2010 resolution passed by NAPSR.[74]

The PRIA estimated that the average annual costs of these proposed changes ($12.8M to $15.3M) would exceed the average annual benefits ($11.3 to $14.2M) over the initial 15-year compliance period.[75] Rather than using actual data on the current safety record of Class 1 gas gathering lines, which PHMSA has not collected, the PRIA made a series of assumptions about the potential impact of the proposed rules in arriving at these estimates.[76] For example, the PRIA used data provided in the 2006 rulemaking and the current proceeding to estimate the mileage affected and compliance costs of the proposed rules. The PRIA also relied on data for transmission lines in Class 1 and 2 locations to estimate the benefits.[77]

3. API-GPA Position

API and GPA support PHMSA's proposal to regulate gas gathering lines in Class 1 locations, but only if the nominal outside diameter threshold is to pipe that is greater than 16 inches. Other than citing to a 2010 NAPSR resolution and a 2014 GAO recommendation concerning pipeline emergency response planning, PHMSA offers no technical support for the 8-inch nominal outside diameter threshold proposed in the NPRM. Conventional gas gathering systems throughout the United States are constructed with pipe ranging from 8 to 16 inches in nominal outside diameter, and there is no data in the record to suggest that these pipelines have a different risk profile than the rural gathering lines that have been exempt from regulation for nearly five decades.

The ongoing effort to develop a new API recommended practice for rural gas gathering lines shows that the new generation of higher risk gas gathering lines in the nation's shale plays are greater than 16 inches in nominal outside diameter. API, GPA, and other interested stakeholders have been working for the past year to develop a recommended practice that complements PHMSA's

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[70] *Id.*
[71] *Id.* at 20,801-808.
[72] *Id.*
[73] *Id.*
[74] PRIA at 101. PHMSA specifically acknowledged that the information provided in its congressionally-mandated gathering line report, which the Agency completed in September 2013 and delivered to Congress in the March 2015, was not considered in developing the rules proposed in the NPRM. NPRM at 20,802.
[75] PRIA at 151.
[76] PRIA 99-117.
[77] *Id.*

current regulations and desire to establish new safety standards for Class 1 gas gathering lines. In response to input provided throughout that process, API recently decided to limit the scope of the new recommended practice to pipelines that are greater than 16 inches in nominal outside diameter. API determined that there is a consensus on the need to establish a risk-based recommended practice for these large diameter rural gathering lines. A consensus does not exist on the need or approach that should be used in establishing a more uniform set of safety practices for smaller diameter gas gathering lines in rural areas.

API and GPA support PHMSA's proposed MAOP criteria for Class 1 gas gathering lines. The MAOP thresholds in the NPRM are currently used to distinguish between Type A and Type B gathering lines.[78] The 20 percent or more of SMYS limitation is also one of the criteria used in determining whether a pipeline is a gas transmission line.[79] So long as PHMSA recognizes that the operating profile of gas gathering systems changes over time, particularly with the rapid production decline curves that occur during the initial phase of a shale play's development, the proposed MAOP thresholds can serve as a useful indicator of potential risk.

Consistent with the comparable requirements for hazardous liquid pipelines, PHMSA should allow Class 1 gas gathering operators to use the MAOP limitation for non-metallic pipe (more than 125 PSIG) if any variable necessary to determine the stress level of metallic pipe is unknown. PHMSA allows operators to use that MAOP threshold if the stress level of steel pipe is unknown in determining whether a rural gathering line is regulated under 49 C.F.R. § 195.11. Allowing Class 1 gas gathering line operators to use the same limitation as an alternative to the design regulations for steel pipe is more efficient and avoids a conflict with the Pipeline Safety Act's non-retroactivity provision.

API and GPA generally support PHMSA's proposal to apply the requirements for Type B gathering lines and emergency plans to regulated Class 1 gathering lines, provided operators can deviate from those requirements if a variance with written technical justification is approved in appropriate program documentation. PHMSA included a similar variance provision in the new regulations for underground gas storage facilities,[80] and operators of newly-regulated Class 1 gas gathering lines should be afforded the same flexibility. Such a provision will allow operators of pipelines constructed with materials not approved for use under PHMSA's regulations to perform repairs or replacements without pursuing the unduly burdensome special permit process. Operators could also use a variance to ensure that Class 1 gas gathering lines are designed, constructed, operated, and maintained in accordance with the latest safety standards and practices.

API and GPA ask PHMSA to consider whether other risk-based concepts can be included in the new regulations to reduce or minimize the burden imposed on operators of Class 1 gas gathering lines that are greater than 16 inches in nominal outside and satisfy the MAOP thresholds described in the previous paragraphs. For example, PHMSA's hazardous liquid pipeline safety regulations use proximity to unusually sensitive areas as a measure of potential environmental impact in determining the regulatory status of rural gathering lines and low-stress lines.[81] The gas IM

[78] 49 C.F.R. § 192.8(b)(2)(table).
[79] *Id.* § 192.3 (definition of transmission line).
[80] *Id*, § 192.12(f).
[81] *Id.* §§ 195.11(a)(2), 195.12(b).

regulations use a pipeline's potential impact radius, and the presence of identified sites or a certain number of buildings intended for human occupancy within the potential impact circle, in determining if a transmission line segment is in a high consequence area.[82] Whether these or other concepts are considered, the critical point for API and GPA is that the new regulations allow operators to effectively and efficiently allocate resources in managing the risks associated with Class 1 gas gathering pipelines that are greater than 16 inches in nominal outside diameter and satisfy the aforementioned MAOP thresholds.

API and GPA urge PHMSA to refer to newly-regulated Class 1 gas gathering lines as "Type C" lines. The NPRM designates these lines as Type A, Area 2 lines, a reference that introduces unnecessary complexity and confusion into the regulations. Using the Type C designation for regulated Class 1 gathering lines is consistent with the current risk framework and provides operators with greater clarity on the applicability of those provisions.

API and GPA also urge PHMSA to clarify the specific gas transmission line regulations that apply to regulated Class 1 gas gathering lines to address certain discrepancies and inconsistencies in the NPRM. Note that for simplicity the list below refers to Type A, Area 1 lines as Type A lines, and Type A, Area 2 lines as Type C lines.

- *Corrosion Control Requirements*. The NPRM included certain exceptions from the corrosion control requirements for Type A lines but did not provide the same exceptions for Type B lines or Type C lines.[83] As a result, the corrosion control requirements for higher-risk Type A lines are less stringent than the requirements for lower-risk Type B lines and Type C lines. PHMSA needs to address that disparity by aligning the list of exceptions to the corrosion control requirements for all regulated gathering lines in the final rule.

- *MAOP Requirements*. Under the NPRM, operators of Type C lines and Type B lines must establish MAOP in accordance with 49 C.F.R. § 192.619.[84] However, PHMSA is proposing to amend § 192.619 in another part of the NPRM by adding a new subsection (e) to the regulation.[85] As currently proposed, § 192.619(e) requires operators of certain gas transmission lines to comply with an elaborate set of MAOP verification requirements in 49 C.F.R. § 192.624.[86] The assumptions laid out in the NPRM and PRIA and congressional mandate that prompted PHMSA to issue § 192.624 confirm that the proposed MAOP verification requirements are only applicable to gas transmission lines, not gas gathering lines. PHMSA affirmed that position in discussing the gas transmission line proposals before the GPAC. To avoid any uncertainty, PHMSA needs to clearly state in the final rule that operators of Type B lines and Type C lines only need to comply with 49 C.F.R. §192.619(a)-(d) in establishing MAOP.

[82] *Id.* §§ 192.901-905.
[83] NPRM at 20,828.
[84] *Id.*
[85] *Id.* at 20,833.
[86] *Id.*

- *Compliance Deadline*. The NPRM provides a 2-year deadline from the effective date of the final rule for operators of Type C lines to achieve compliance, unless the PHMSA Administrator finds that a later deadline is justified in a particular case.[87] By way of comparison, the March 2006 final rule provided a series of staggered deadlines over a 3-year period for achieving compliance with the requirements for regulated gathering lines, *i.e.*, October 15, 2007, for damage prevention and MAOP establishment; April 15, 2008, for line markers and public awareness; and April 15, 2009, for corrosion control.[88] The rules proposed in the NPRM affect more pipeline operators and mileage, and PHMSA does not offer any justification in the NPRM or PRIA for providing a shorter compliance deadline in this proceeding. Operators of existing Type C lines need additional time to achieve compliance with the proposed rules. A 2-year initial compliance deadline should be provided for the damage prevention, public awareness, line marker, and emergency response requirements and establishing MAOP. A determination as to whether a pipeline qualifies as a Type C line will necessarily need to be made as part of those efforts. A 3-year initial compliance deadline should be provided for the leak detection and repair requirements. A 5-year compliance deadline should be provided for the corrosion control requirements.

- *Class Location Changes*. PHSMA should clarify the regulations proposed in the NPRM that would apply to gathering lines that become regulated due to changes in class location or an increase in dwelling density.[89] The Pipeline Safety Act prohibits PHMSA from retroactively applying design, construction, initial inspection, or initial testing requirements to pipelines in existence at the time when those requirements were adopted. The non-retroactivity provision applies to existing gathering lines that become regulated due to changes in class location or an increase in dwelling density. Accordingly, the proposed regulation in section 192.9(f) should be amended to clearly state that none of the design, installation, construction, initial inspection, and initial testing requirements in Part 192 apply to those lines.

PHMSA is proposing to amend the existing regulation that lists the safety standards that apply to higher stress, onshore gas gathering lines in Class 2, 3, or 4 locations.[90] These gathering lines, currently designated as Type A lines, are subject to the requirements for gas transmission lines, except for the IM requirements in Subpart O and the provisions relating to the accommodation of inline inspection tools.[91] PHMSA is proposing to expand that list of exceptions to accommodate many of the new proposals offered in the NPRM that would otherwise apply to gas transmission line operators.

Two of the most significant proposals in the NPRM are not on the amended list of exceptions for Type A lines: (1) the proposed regulation (49 C.F.R. § 192.607) for verifying pipeline materials where reliable, traceable, verifiable, and complete records are lacking, and (2) the proposed regulations (49 C.F.R. §§ 192.619(e), 192.624) for verifying MAOP through the use of pressure

[87] *Id.* at 20,828.
[88] 49 C.F.R. § 192.9(e).
[89] NPRM at 20,828.
[90] *Id.*
[91] 49 C.F.R. § 192.9(c).

testing, pressure reductions, engineering critical assessments, alternative technologies, or pipeline replacements. The congressional mandate in Section 23 of the Pipeline Safety Act of 2011[92] and assumptions laid out in the NPRM and PRIA make clear that these proposals may only be applied to gas transmission lines. There is no other basis in the record for requiring operators of Type A lines to comply with these requirements. Accordingly, the proposed pipeline materials and MAOP verification regulations (49 C.F.R. §§ 192.607, 192.619(e), 192.624) must be added to the list of exceptions from the transmission line requirements for operators of Type A lines.

Consistent with the joint positions described above, API and GPA suggest that PHMSA adopt the following regulatory language in the final rule:

§ 192.8(c) How are gathering lines and regulated onshore gathering lines determined?

Type	Feature	Area	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**	If the gathering line 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

[92] Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub. L. No. 112-90, § 23, 125 Stat. 1904, 1918 (codified at 49 U.S.C. § 60139).

		(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	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	**—Metallic pipe greater than 16 inches in nominal outside diameter and the MAOP produces a hoop stress of 20 percent or more of SMYS. If the stress level is unknown, an operator must either determine the stress level according to the applicable provisions in subpart C of this part, or use the MAOP limitation for non-metallic pipe** **—Non-metallic pipe greater than 16 inches in nominal outside diameter and the MAOP is more than 125 PSIG (862 kPa)**	**Class 1 location**	**None**

§ 192.9 What requirements apply to gathering lines?

* * * * *

(c) *Type A lines*. An operator of a Type A, Area 1 regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, **except the requirements in §§ 192.13(d)-(e), 192.150, and 192.319(d), 192.461(a)(4) and (f), 192.465(f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607 (including any references in other requirements), 192.619(e) (including any references in other requirements), 192.624 (including any references in other requirements), 192.631, 192.710, 192.711, 192.713**, and in subpart O of this part. However, an operator of a Type A, Area 1 regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) *Type B lines*. An operator of a Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines**, except the requirements in §§ 192.13(d)-(e), 192.150, and 192.319(d), 192.506, any references to §§ 192.607, 192.619(e), or 192.624, and 192.631**;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines**, except the requirements in §§ 192.461(a)(4) and (f), 192.465(f), 192.473(c), 192.478, 192.485(c), and 192.493**;

* * * * *

(5) Establish the MAOP of the line under § 192.619**(a)-(d), except for any references to §§ 192.607 or 192.624**;

* * * * *

(e) *Type C lines*. Except as provided in paragraph (3) of this subsection, an operator of a Type C regulated onshore gathering line must:

(1) Comply with the requirements in subsection (d) of this section for Type B lines; and

(2) Implement an emergency plan in accordance with § 192.615, except for the requirements in § 192.615(a)(3).

(3) An operator may deviate from the requirements in paragraphs (1)-(2) of this subsection if a variance with written technical justification is included in appropriate program documentation. A subject matter expert must conduct a review to ensure that the design, construction, testing, operation, maintenance, integrity, and overall safety of the affected pipeline facility will not be adversely impacted by the variance. The subject matter expert must provide the results of that review to a senior executive officer, vice president, or higher officer in writing for approval. A variance cannot be used if the Associate Administrator notifies the operator that the variance adversely impacts the design, construction, operations, maintenance, integrity, or overall safety of the affected pipeline facility.

(f) If a regulated onshore gathering line existing on **[effective date of the final rule]** was not previously subject to this part, an operator has until:

(1) [date two years after effective date of the final rule] to comply with the applicable requirements of this section for the damage prevention, public education, MAOP, line markers, and emergency plans;

(2) [date three years after effective date of the final rule] to comply with the applicable requirements for leak detection and repair; and

(3) [date five years after effective date of the final rule] to comply with the applicable requirements for corrosion control and any other provisions applicable to Type A lines

unless the Administrator finds a later deadline is justified in a particular case.

(f) If, after **[effective date of the final rule]**, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has one year for Type B lines **and Type C lines** and two years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section. **Nothing in this subsection requires an operator to comply with the design, installation, construction, initial inspection, or initial testing requirements in this part.**

C. Reporting Requirements for Class 1 Gas Gathering Lines

Current Rules: PHMSA's reporting requirements only apply to Type A lines and Type B lines.

PHMSA Proposal: Whether regulated or not, operators of all Class 1 gas gathering lines must obtain an OPID and comply with PHMSA's incident, safety-related condition, and annual reporting requirements.

API-GPA Position: Type C gathering line operators should obtain an OPID, file abbreviated annual reports, and submit incident reports. Operators of unregulated Class 1 gas gathering lines should obtain an OPID, file abbreviated annual reports, and submit incident reports (only for deaths or injuries involving in-patient hospitalization).

1. Current Rules

Operators of Type A and Type B gathering lines must comply with PHMSA's federal reporting requirements, including the provisions for providing immediate notification of certain incidents, submitting annual reports, reporting safety-related conditions, and obtaining an OPID.[93] By

[93] 49 C.F.R. Part 191.

statute, Type A and Type B gathering line operators are not required to submit geospatial data to the NPMS.[94] Class 1 gas gathering lines are not currently subject to any of the federal reporting requirements.[95]

2. *PHMSA's Proposal*

The NPRM proposed to apply PHMSA's reporting requirements to all Class 1 gas gathering line operators (whether regulated or not), except for the obligation to submit data to the NPMS. Specifically, the NPRM would require Class 1 gas gathering operators to submit incident reports, safety-related condition reports, reports for MAOP exceedances, and annual reports. The NPRM also proposed to require all Class 1 gas gathering line operators to submit information to the National Operator Registry.

3. *API-GPA Position*

API and GPA support PHMSA's proposal to apply the federal reporting requirements to Class 1 gas gathering lines, but only to a limited extent. Type C gathering line operators should be required to obtain an OPID, file abbreviated annual reports, and submit incident reports. Operators of unregulated Class 1 gas gathering lines should be required to obtain an OPID, file abbreviated annual reports, and submit incident reports for fatalities or injuries involving in-patient hospitalization.

Although the Pipeline Safety Act provides PHMSA with the authority to collect "information pertinent to [PHMSA's] ability to make a determination as to whether and to what extent to regulate gathering lines," the proposal to indiscriminately extend all of the reporting requirements to Class 1 gas gathering line operators fails to meet that standard.[96] The NPRM and PRIA do not explain why operators must provide all of the data sought in PHMSA's reports for the agency to make a reasoned determination on the need for future regulation. As described in more detail below, PHMSA can obtain sufficient data on the safety of Class 1 gas gathering lines through the submission of incident and annual reports.

- *Incident Reports*. PHMSA proposed in the NPRM to apply the incident reporting requirements to operators of all Class 1 gas gathering lines, whether regulated or not.[97] API and GPA agree that operators of Type C lines should be subject to the same incident reporting requirements as regulated Type A and Type B lines. However, API and GPA do not agree that operators of unregulated Class 1 gas gathering lines should be required to report all incidents. Operators of unregulated gathering lines should be required to report incidents resulting in a death or injury necessitating in-patient hospitalization, which clearly have a direct impact on public safety. The other events that trigger the incident reporting requirements (estimated property damage of $50,000 or more, unintentional estimated gas loss of three million cubic feet or more, or an event that is significant in the judgment of the operator) do not always have that same direct impact. Requiring

[94] 49 U.S.C. § 60132(a) (providing an exception for gathering and distribution lines); 49 C.F.R. § 191.29.
[95] 49 C.F.R. § 191.1(b)(4).
[96] 49 U.S.C. § 60117(b).
[97] NPRM at 20,824-20,825.

unregulated gathering line operators to report those incidents would impose an undue burden on the industry.

- *Annual Reports*. The NPRM proposed to apply the annual reporting requirement to all Class 1 gathering lines.[98] API and GPA agree that operators of Type C lines should be subject to the same annual reporting requirements as regulated Type A and Type B lines. API and GPA also agree that unregulated Class 1 gas gathering line operators should be required to submit annual reports. However, Class 1 gas gathering line operators should not be required to provide the same information in annual reports as operators of transmission and distribution lines. PHMSA should develop an abbreviated annual report form for gas gathering lines, and that form should only ask operators to submit information that is readily available directly relevant to gas gathering operations. PHMSA's regulations have not applied to gas gathering lines in Class 1 location for the past five decades, and operators of these systems may not have the same detailed records as operators of traditionally regulated transmission and distribution systems. While that information will become more readily over time, PHMSA should carefully limit the data that Class 1 gas gathering line operators need to provide in annual reports, particularly during this initial phase of regulation. Information that would be appropriate for the abbreviated annual reporting form includes gathering line mileage by state, outside diameter, class location, Type (A, B, C, Unregulated), material, and decade of installation. Operators should be allowed to respond with unknown if information is not available.

- *Safety-Related Conditions, Including MAOP Exceedances*. The NPRM proposed to apply the requirement for reporting of safety-related conditions, including MAOP exceedances, to unregulated gathering lines.[99] PHMSA clarified in a series of webinars held immediately prior to the end of the comment of the period and during the GPAC's review of the NPRM's gas transmission line proposals that the agency did not intend to apply these reporting requirements to operators of unregulated gathering lines. API and GPA support that clarification and are offering text to that effect for PHMSA to consider adopting in the final rule.

- *OPID Requirements*. The NPRM proposed to apply all of the requirements in the National Registry of Pipeline and LNG operators to Class 1 gas gathering lines, including the provisions for OPID requests and reporting certain changes to PHMSA within 60-day windows.[100] API and GPA agree that operators of Type C lines should be subject to the same requirements as regulated Type A and Type B lines. However, operators of unregulated Class 1 gas gathering lines should only be required to obtain an OPID, which is necessary for administrative purposes in filing incident and annual reports. They should not be required to report the other changes that trigger the 60-day notifications to PHMSA.

Consistent with the foregoing joint positions, API and GPA suggest that PHMSA adopt the following changes to Part 191 in the final rule:

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[98] *Id.*
[99] *Id.*
[100] *Id.*

§ 191.1 Scope.

(a) This part prescribes requirements for the reporting of incidents, safety-related conditions, exceedances of maximum allowable operating pressure (MAOP), annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of gas pipeline facilities located in the United States or Puerto Rico, including 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).

(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 PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9;

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

(4) Onshore gathering of gas—

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

(ii) Through an onshore pipeline that is not a regulated onshore gathering line (as determined in § 192.8 of this chapter)**, except for reporting an incident that results in a death or personal injury involving in-patient hospitalization in accordance with §§ 191.3, 191.5, and 191.15, the report submission requirements in § 191.7(a) and (d), the annual reporting requirements for gas gathering pipeline systems in § 191.17, and the OPID requirements in § 191.22(a) and (d)**; and

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

V. Conclusion

API and GPA share PHMSA's commitment to pipeline safety and appreciate the opportunity to submit this joint position paper on the proposed changes to the federal safety standards and reporting requirements for gas gathering pipelines. Please feel free to contact us directly if you have any additional questions or concerns.

Sincerely,

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