



VIA ELECTRONIC FILING

November 2, 2017

Docket Management Facility
U.S. Department of Transportation
1200 New Jersey Ave, S.E.
Washington, D.C. 20590

Re: Docket No. OST-2017-0069: Notification of Regulatory Review; Federal Register Vol. 82, No. 189 (Monday, October 2, 2017)

Dear Madam Secretary,

On October 2, 2017, the Office of the Secretary of Transportation (OST) published a notice in the *Federal Register* asking for input on existing regulations and other agency actions that the Department of Transportation (DOT) should consider for repeal, replacement, suspension, or modification.¹ As OST explained in the notice, DOT is obligated to review its regulations and other agency actions under a series of departmental policies, executive orders, and statutory provisions, and DOT adheres to the provisions in a repeating 10-year plan in conducting those reviews.² OST further explained that President Trump recently issued three executive orders that require federal agencies to provide an additional level of scrutiny in reviewing existing regulations and other agency actions, including those that potentially burden the development or use of domestically produced energy resources.³

GPA Midstream Association (GPA Midstream) has served the U.S. energy industry since 1921.⁴ GPA Midstream 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

¹ Notification of Regulatory Review, Docket No. OST-2017-0069, 82 Fed. Reg. 45,750-45,753 (Oct. 2, 2017).

² *Id.* at 45,751.

³ *Id.* The three executive orders are: (1) Executive Order 13,771 on Reducing Regulation and Controlling Regulatory Costs, which generally requires that federal agencies identify two existing regulations that will be repealed for every new regulation proposed or otherwise promulgated; (2) Executive Order 13,777 on Enforcing the Regulatory Reform Agenda, which directs the head of all agencies to designate a Regulatory Reform Officer and create a Regulatory Reform Task Force to oversee the implementation of President Trump’s regulatory reform initiatives and policies; and (3) Executive Order 13,783 on Promoting Energy Independence and Economic Growth, which requires federal agencies to review and make recommendations for addressing existing regulations and other actions that potentially burden the development or use of domestically-produced energy resources.

⁴ Additional information about GPA Midstream is available at <https://gpaglobal.org/>. Prior to April 2016, GPA Midstream was known as the Gas Processors Association.

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.

GPA Midstream welcomes OST's request for comments on DOT regulations and other agency actions that impose unjustifiable burdens on the regulated community and the production or use of domestically produced energy resources. GPA Midstream's member companies gather and process domestic energy products, and the country cannot enjoy the full benefits of those products—whether as a source of fuel for the nation's economy or as the feedstock for our growing petrochemical industry—without an efficient and effective transportation system. GPA Midstream's member companies are particularly dependent on the nation's pipeline infrastructure. Pipelines, the safest and most reliable means of transporting energy products, transport nearly all of the natural gas produced in the United States; most of the nation's crude oil, NGLs, and other petroleum products are transported by pipeline as well.

The Pipeline and Hazardous Materials Safety Administration (PHMSA or the Agency) is the DOT agency responsible for administering the nation's Pipeline Safety Laws.⁵ PHMSA's principal obligation is to establish and enforce federal safety standards for gas and hazardous liquid pipeline facilities and persons engaged in the transportation of those products. PHMSA's pipeline safety standards apply to most gas and hazardous liquid pipelines in the United States, and they are the only safety standards that apply to interstate pipeline facilities, except for certain qualifying state damage prevention laws.⁶ PHMSA also oversees a federal certification and grant program that allows state authorities to assume responsibility for regulating the safety of intrastate pipeline facilities.⁷ State authorities can enter into separate agreements with PHMSA to act as agents in performing inspection of interstate pipeline facilities as well.⁸

GPA Midstream believes that there are a number of PHMSA regulations and other agency actions that impose unjustifiable burdens on the pipeline industry, and that DOT can repeal, replace, modify, or suspend those actions without compromising public safety. GPA Midstream has identified each of the regulations or actions below with a specific reference and described the burden that the action imposes on the regulated community. GPA Midstream has also offered less burdensome alternatives and provided examples of the entities and projects that are adversely affected. While GPA Midstream appreciates PHMSA's commitment to pipeline safety, our member companies believe that the efficiency and effectiveness of the federal pipeline safety program will be greatly improved if the changes described below are implemented.

⁵ 49 U.S.C. § 60101 et seq.

⁶ 49 U.S.C. § 60104(c).

⁷ A state authority must submit an annual certification to PHMSA, agree to adopt the minimum federal safety standards, and meet other program requirements to participate in the federal pipeline safety program. In exchange for doing so, a state authority is eligible to receive federal grant funding to offset the costs of administering that program. A state authority that obtains a certification can also apply additional or more stringent safety standards to any pipeline facilities that are covered under the terms of that certification, so long as those standards are compatible with the minimum federal requirements. 49 U.S.C. § 60105.

⁸ 49 U.S.C. § 60106.

1. Gas Gathering Lines

Specific Reference: Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Notice of Proposed Rulemaking, 81 Fed. Reg. 20,721 (Apr. 8, 2016)

Burden Imposed: \$28-Plus Billion in Initial 15-Year Compliance Costs

Less Burdensome Alternatives: Incident and Annual Reporting, Data Collection, and Analysis

Affected Entities: 3,597 Gathering Companies

GPA Midstream's member companies primarily operate pipelines known as gathering lines. Gathering lines are pipelines that transport oil and natural gas from production sites to central collection points. These lines generally operate at low pressures and are smaller in diameter than transmission lines, although recent advances in the oil and gas industry are making higher pressure, larger diameter gathering lines more prevalent in the nation's shale plays. GPA Midstream's member companies also operate the processing plants that are located at the central collection points in gathering systems. Processing plants remove impurities and NGLs to make pipeline quality gas suitable for transportation in long-haul transmission lines.

PHMSA established the current federal safety standards for onshore gas gathering lines in a 2006 final rule.⁹ Those rules generally require operators to follow an industry standard, American Petroleum Institute (API) Recommended Practice 80, Guidelines for the Definition of Onshore Gas Gathering Lines (1st ed., April 2000) (RP 80), to determine the extent of gas gathering operations. A two-tiered, risk-based regime of safety standards applies to regulated gas gathering lines that meet certain criteria. GPA Midstream and its member companies were very involved in the rulemaking proceeding that produced the current gathering line rules, providing PHMSA with safety data on gathering lines and participating on the standards development group that created RP 80.

In August 2011, PHMSA issued an advance notice of proposed rulemaking (ANPRM) asking for public comment on whether the regulations for onshore gas gathering lines should be changed to accommodate recent developments in the nation's shale plays.¹⁰ GPA Midstream responded to the ANPRM by urging PHMSA to retain the existing, risk-based approach for regulating gas gathering lines.¹¹ GPA Midstream also recommended that PHMSA obtain additional data before making any changes to the current regulations, noting that Congress had directed PHMSA in Section 21 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Act) to conduct a review and provide recommendations on whether existing federal and state regulations were adequate to ensure the safety of gas and hazardous liquid gathering lines.¹² GPA Midstream urged PHMSA not to change the gathering line regulations until the Agency had completed that study.

⁹ 49 C.F.R. §§ 192.8 to 192.9; *Gas Gathering Line Definition: Alternative Definition for Onshore Lines and New Safety Standards*, Final Rule, 71 Fed. Reg. 13,289,13,295 (Mar. 15, 2006).

¹⁰ *Pipeline Safety: Safety of Gas Transmission Pipelines*, 76 Fed. Reg. 53,086 (Aug. 25, 2011).

¹¹ See Attachment 1.

¹² Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Pub. L. 112-90, § 5(a)(2) (Jan. 3, 2012).

Without adequately completing the study required in Section 21 of the 2011 Act or obtaining any new data on gas gathering lines, PHMSA issued a notice of proposed rulemaking (Gas NPRM) in April 2016 with significant changes to the gathering line regulations.¹³ PHMSA proposed new definitions for determining what qualifies as an onshore gas gathering line; new safety standards for regulated onshore gas gathering lines, including for certain historically-exempt rural gas gathering lines; and new reporting requirements for all gas gathering lines.¹⁴ PHMSA also released a Preliminary Regulatory Impact Analysis (PRIA) with the Gas NPRM that purportedly addressed the potential economic effects of the proposed gathering line regulations.¹⁵ The PRIA estimated that the costs of the gathering line proposals would exceed the benefits by approximately \$1 million over the initial 15-year compliance period.

GPA Midstream submitted detailed comments in response to the NPRM.¹⁶ Like many other industry commenters, GPA Midstream explained that PHMSA failed to comply with the rulemaking requirements in the Pipeline Safety Act and Administrative Procedure Act in developing the proposed gathering line regulations. GPA Midstream noted that the record did not contain the substantial evidence necessary to support PHMSA's proposals, and that the proposed changes generally lacked an adequate technical justification and supporting rationale. GPA Midstream also observed that the PRIA's economic analysis contained several fundamentally flawed assumptions, a point confirmed by a third-party analysis that another industry trade organization submitted showing that the costs of the proposed gathering line rules would exceed the benefits by more than \$28 billion during the initial 15-year compliance period.¹⁷ GPA Midstream urged PHMSA to collect and analyze additional data before moving forward with any proposed changes to the gas gathering line regulations.

GPA Midstream's member companies are extremely concerned with the approach that PHMSA is taking in this rulemaking proceeding. PHMSA proposed extensive changes to the gathering line regulations without completing the study required by Section 21 of the 2011 Act or identifying any data that demonstrates that the existing regulations are inadequate. PHMSA staff acknowledged during the public comment period that the Gas NPRM's gathering line proposals contained significant drafting errors, a particularly troubling statement given the length of time that the Agency had to consider the proposed rules between the ANPRM and the Gas NPRM.¹⁸ Finally, and perhaps most significantly, the PRIA overstated the potential benefits—

¹³ *Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines*, Notice of Proposed Rulemaking, 81 Fed. Reg. 20,721 (Apr. 8, 2016). In May 2015, PHMSA delivered a report to Congress on the regulation of gas gathering lines in an effort to comply with Section 21 of the 2011 Act. That report, apparently completed in September 2013, summarized existing federal and state regulations for gathering lines, but did not provide any analysis of the adequacy of those regulations or make the required recommendations to Congress on the need for future action. PHMSA acknowledged in the NPRM that the report was not considered in developing any of the proposed modifications to the gathering rules.

¹⁴ 81 Fed. Reg. at 20,801-20,808, 20,824-20,828.

¹⁵ The PRIA is available in the docket at <https://www.regulations.gov/docket?D=PHMSA-2011-0023>.

¹⁶ See Attachment 2.

¹⁷ ICF International, Cost and Benefit Impact Analysis of the PHMSA Natural Gas Gathering and Transmission Safety Regulation Proposal, Prepared for the American Petroleum Institute (July 1, 2016) (ICF Study) (available in the docket at <https://www.regulations.gov/document?D=PHMSA-2011-0023-0381>).

¹⁸ PHMSA staff made these concessions during June 2016 webinars for the NPRM. Audio files of the public discussion are available at <https://primis.phmsa.dot.gov/meetings/>.

and grossly underestimated the potential costs—of the proposed gathering line regulations, miscalculating the economic impact by nearly \$30 billion according to a third-party analysis.¹⁹

The midstream industry will experience significant harm if PHMSA adopts the gathering line rules proposed in the Gas NPRM. The potential compliance costs are staggering and would have a disproportionate economic impact on small operators. A third-party economic analysis submitted by another industry trade association concluded that the Gas NPRM would affect 3,597 gathering companies, and the annual compliance costs would consume approximately 90% of the revenue generated by the industry's 2,223 small gathering companies.²⁰ Large companies would also be adversely affected, particularly by PHMSA's efforts to retroactively apply design standards and recordkeeping requirements to existing gathering lines and to assert jurisdiction over historically-exempt production and gathering lines.

Despite the obvious flaws and adverse impacts that would result from adopting the Gas NPRM, PHMSA has indicated that the gathering provisions will be presented to the Gas Pipeline Advisory Committee (GPAC) for consideration in the coming months.²¹ GPA Midstream does not support such an action and reiterates that PHMSA must collect and analyze additional data before moving forward with any proposed changes to the current gathering line regulations. While GPA Midstream is willing to support PHMSA in an effort to collect additional data, our member companies oppose any further consideration of the Gas NPRM's gathering line provisions until that process is complete.

GPA Midstream is also concerned with the proposals for gas transmission lines, many of which would become applicable to regulated gas gathering lines under the NPRM. For example, proposed § 192.67 states that "[e]ach operator of transmission pipelines *must acquire and retain* for the life of the pipeline the *original steel pipe manufacturing records* that document tests, inspections, and attributes required by the manufacturing specification in effect at the time the pipe was manufactured..."²² Many of the pipelines subject to PHMSA regulation were put in the ground prior to 1970. PHMSA cannot expect operators to acquire original records now, almost four decades after construction, when those records were not previously required. PHMSA should revise this proposal to state explicitly that this requirement is applicable prospectively from the date of the final rule. The proposed requirements for spike testing, material documentation, and validation of maximum allowable operating pressure (MAOP) are areas of concern as well.²³ These proposals are unnecessarily complex and go well beyond the congressional mandates in the 2011 Act and San Bruno-related NTSB safety recommendations that PHMSA cited as the supporting authority in the NPRM. PHMSA should respect the will of Congress by limiting these proposals to only those transmission lines identified in the 2011 Act.²⁴

¹⁹ ICF Study at pp. 1-6, 11-123.

²⁰ Id. at pp. 5-6.

²¹ 49 U.S.C. § 60115. GPAC is the federal advisory committee that reviews and provides recommendations on PHMSA's gas pipeline safety rulemaking proposals.

²² 81 Fed. Reg. 20,721 at 20,828.

²³ See Attachment 2.

²⁴ GPA Midstream shares the cost-benefit concerns raised by the American Petroleum Institute (API) and Interstate Natural Gas Association of America (INGAA) in their economic analyses of the proposed MAOP verification rules. API found that the actual cost of the transmission line proposals in the NPRM would be \$4.5B, or more than \$4B

Attached to this correspondence are the comment letters that GPA Midstream submitted to PHMSA in response to the ANRPM and the Gas NPRM.²⁵ Those letters provide a detailed description of the specific concerns that GPA Midstream's member companies have with the proposed changes to the gas gathering line regulations and the adverse impacts that the midstream industry would experience if PHMSA adopts those proposals in a final rule.

2. Hazardous Liquid Pipelines

Specific Reference: *Pipeline Safety: Safety of Hazardous Liquid Pipelines*, Notice of Proposed Rulemaking, 80 Fed. Reg. 61,610 (Oct. 13, 2015)

Burden Imposed: Approximately \$600 Million in Total Annual Compliance Costs²⁶

Less Burdensome Alternatives: Streamlined Annual and Written Accident Reporting for Unregulated Rural Gathering Lines; Withdrawal or Modification of Other Proposals

Entities Affected: Approximately 193,000 Miles of Onshore Hazardous Liquid Pipelines, Including 26,000 to 36,000 Miles of Unregulated Rural Gathering Lines

In October 2015, PHMSA issued an NPRM proposing to make significant changes to the hazardous liquid pipeline safety regulations in 49 C.F.R. Part 195 (Hazardous Liquid NPRM).²⁷ The proposed changes included requiring operators of gravity lines and unregulated rural gathering lines to submit certain reports; requiring inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events; requiring periodic assessment of pipelines not already subject to the integrity management (IM) program regulations; requiring operators to have leak detection systems on non-IM pipelines; establishing more stringent pipeline repair criteria; and requiring operators to make pipelines in high consequence areas (HCAs) capable of accommodating inline inspection tools within 20 years, unless the pipeline's construction would not permit that accommodation.

In January 2016, GPA Midstream Association submitted comments responding to the Hazardous Liquid NPRM. GPA Midstream explained that PHMSA failed to account for the full cost of extending the annual, accident, and safety-related condition reporting requirements to unregulated rural gathering lines, and that PHMSA could make a determination on the need to establish additional regulations for these lines by obtaining a narrower subset of information

higher than the estimate provided in the PRIA, and that the MAOP verification requirements would be responsible for approximately \$772M of that total cost. API also found that PHMSA violated standard cost-benefit methodology by improperly attributing approximately \$2.7B in benefits to the proposed pipeline materials and MAOP verification rules based on the erroneous assumption that the Part 192 tensile strength testing requirements apply retroactively to existing gas pipelines. INGAA identified several flawed assumptions that PHMSA used in developing the PRIA, including underestimating the costs of (1) conducting spike tests for legacy pipe, (2) subjecting short, discontinuous segments in moderate consequence areas to pressure tests, and (3) removing a pipeline from service to complete testing, which results in additional Federal Energy Regulatory Commission reservation charge credits to shippers. GPA Midstream asks DOT to consider these concerns in reviewing the cost-effectiveness of PHMSA's proposals.

²⁵ See Attachments 1 and 2.

²⁶ American Petroleum Institute, Hazardous Liquids Rule Cost/Benefit Analysis: A Review of the Hazardous Liquid Pipelines Notice of Proposed Rulemaking (NPRM) and Preliminary Regulatory Impact Analysis (PRIA) (Jul. 11, 2016) (available at <https://www.regulations.gov/document?D=PHMSA-2010-0229-0132>).

²⁷ *Pipeline Safety: Safety of Hazardous Liquid Pipelines*; Proposed Rule, 80 Fed. Reg. 61,610 (October 13, 2015).

from operators in annual reports and written accident reports. GPA Midstream also explained that the available data did not justify PHMSA's proposals to require operators of regulated rural gathering lines to conduct periodic pipeline assessments or install leak detection systems, and that neither of these proposals would produce a meaningful increase in pipeline safety. GPA Midstream provided comments on other aspects of the Hazardous Liquid NPRM as well, including the proposals to require operators to perform pipeline inspections after extreme weather, natural disasters, and other similar events, to conduct periodic integrity assessments of non-IM pipelines, and to comply with the IM repair criteria for pipelines located outside of HCAs.²⁸

On January 13, 2017, PHMSA released a pre-publication version of the final rule. While not yet published by the Office of the Federal Register (OFR), that version of the final rule required operators of unregulated rural gathering lines to submit annual, accident (written reports only), and safety-related condition reports. The final rule did not require operators of regulated rural gathering lines to conduct periodic pipeline assessments or install leak detection systems, and it did not impose more stringent repair criteria and remediation deadlines for non-IM pipelines. On January 20, 2017, shortly after the inauguration of President Trump, the White House issued a memo imposing a temporary moratorium on most regulatory actions.²⁹ The memo indicated that any final rules awaiting publication by the OFR should be withdrawn and returned to the originating agency for further review. The Hazardous Liquid final rule, which had not yet been published by the OFR, was returned to PHMSA for further review under the memo.

GPA Midstream supports many of the changes that PHMSA made in the pre-publication version of the final rule. As GPA Midstream explained in its comments responding to the Hazardous Liquid NPRM, the available data does not justify requiring operators of regulated rural gathering lines to conduct periodic pipeline assessments or install leak detection systems. The record also does not contain the technical support necessary to impose more stringent repair criteria and remediation deadlines for non-IM pipelines. GPA Midstream supports PHMSA's decision to remove these proposals from the pre-publication version of the final rule and urges the Agency to follow that same path in the future.

On the other hand, GPA Midstream does not support PHMSA's decision to apply the safety-related condition reporting requirements to unregulated rural gathering lines. The information provided in safety-related condition reports does not shed any light on whether PHMSA should establish additional safety standards for these lines, and the burden imposed by requiring operators to submit those reports far outweighs any potential benefits. As GPA Midstream explained in its comments to the Hazardous Liquid NPRM, PHMSA can obtain all the information necessary to make a decision on the regulatory status of rural gathering lines from the data provided in written accident reports and a streamlined version of the annual report.

²⁸ See <https://www.regulations.gov/document?D=PHMSA-2010-0229-0095> (last accessed on October 24, 2017).

²⁹ <https://www.whitehouse.gov/the-press-office/2017/01/24/implementation-regulatory-freeze> (last accessed on October 24, 2017).

Attached to this correspondence is the comment letter that GPA Midstream submitted in response to the NPRM.³⁰ The letter provides a more detailed description of GPA Midstream's concerns and the adverse impacts that the midstream industry would experience if PHMSA adopted the proposals in the NPRM.

3. Emergency Orders

Specific Reference: *Pipeline Safety: Enhanced Emergency Order Procedures*, Interim Final Rule, 81 Fed. Reg. 70,980 (Oct. 14, 2016) (codified at 49 C.F.R. §§ 190.3, 190.236, 190.237)

Burden Imposed: Not Available

Less Burdensome Alternatives: Require All Petitions for Review to Be Heard by an Administrative Law Judge, Modify the Emergency Order Definition and Imminent Hazard Standard, Incorporate Additional Due Process Protections

Entities Affected: All Owners and Operators of Pipeline Facilities

On June 22, 2016, President Obama signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (PIPES Act) into law. Section 16 of the PIPES Act gave PHMSA the authority to issue emergency orders if “an unsafe condition or practice, or a combination of unsafe conditions and practices, constitutes or is causing an imminent hazard, . . . but only to the extent necessary to abate the imminent hazard.”³¹ The statute allows emergency orders to be issued without prior notice or the opportunity for public comment and to apply broadly to owners and operators of gas and hazardous liquid pipeline facilities. Given the extraordinary nature of these powers, the statute provides additional procedural protections to the regulated community, including the right to receive expedited administrative review of an emergency order before an administrative law judge (ALJ) and, if necessary, obtain expedited judicial review in the federal district courts.

Section 16 required PHMSA to establish temporary regulations for issuing emergency orders by August 21, 2016, and PHMSA promulgated those regulations on October 14, 2016, in an interim final rule (IFR). PHMSA issued the IFR without providing the public with prior notice, finding that the statutory deadline in the PIPES Act allowed the agency to waive that requirement under the good cause exception in the Administrative Procedure Act (APA). PHMSA provided the public with a 60-day, post-publication comment period, and six industry trade associations, including GPA Midstream, submitted comments expressing concerns with various provisions in the IFR. Section 16 required PHMSA to issue final emergency order regulations by March 19, 2017, but PHMSA has not issued those regulations as of the date of this letter.

The IFR created a temporary process for issuing emergency orders. If the Administrator determines that an imminent hazard exists, an emergency order can be issued without prior notice or the opportunity for a hearing. The Administrator must consult with appropriate entities knowledgeable in pipeline safety and consider certain additional factors before issuing an emergency order, including the impact on public health and safety, the economy, national

³⁰ See Attachment 3.

³¹ 49 U.S.C. § 60117(o)(1).

security, and reliability and continuity of service, and the result of any prior consultations. The emergency order must contain a written description of the violation, conditions, and practices causing the imminent hazard; a list of the entities subject to the order; the restrictions, prohibitions, or safety measures imposed; the standards and procedures for obtaining relief; and a statement of how the order is tailored to abate the imminent hazard and why the imminent hazard could not be abated with a corrective action order or safety order. Emergency orders are served by publication in the *Federal Register* and posted on the PHMSA website.

The IFR also created a temporary, two-track administrative process for obtaining review of an emergency order. An entity subject to and aggrieved by an emergency order may either seek a formal hearing before an ALJ, or request a decision without a formal hearing from the Associate Administrator for Pipeline Safety. However, the Associate Administrator has discretion to convert a request for an informal hearing to a formal one, and vice versa, and can deny a request for a formal hearing if he or she determines that there are no material facts in dispute. The Associate Administrator can also assign a petition for an informal hearing to the ALJ even if the petitioner does not make that request. In addition, the Associate Administrator can consolidate petitions for review that share common issues of law or fact if more than one petition is filed. In cases where a formal hearing is held, an ALJ must issue a report and recommendation within 25 days of the petition's receipt by the Associate Administrator. A party aggrieved by an ALJ's report and recommendation can file a petition for reconsideration and the opposing party can file a response. The timing to file a petition for reconsideration is limited to one day from receipt of the ALJ report. In all cases, the Associate Administrator must issue a final decision within 30 days of receiving a petition.

Consistent with the requirements in Section 16 of the PIPES Act, the temporary regulations provide that an emergency order will cease to be effective if the Associate Administrator or ALJ has not disposed of a petition within 30 days of receipt, unless the Administrator issues a written determination that the imminent hazard continues to exist. If a written determination is issued, the emergency order remains in effect subject to the right to receive expedited judicial review. The temporary regulations codify the right in Section 16 of the PIPES Act to seek expedited judicial review in an appropriate U.S. District Court. The right to judicial review arises after the Associate Administrator issues a final decision on a petition or upon the Administrator's issuance of a written determination extending an emergency order if the administrative review process is not completed within 30 days.

GPA Midstream has significant concerns with the temporary emergency order regulations. First and foremost, GPA Midstream does not believe that PHMSA had good cause to issue the IFR without complying with the notice-and-comment requirements in the APA. The good cause exception allows a federal agency to issue a final rule without providing the public with prior notice and the opportunity to comment if doing so would be impracticable, unnecessary, or contrary to the public interest.³² The federal courts have emphasized that the good cause exception is to be narrowly construed, and that the APA's notice-and-comment

³² 5 U.S.C. 553(b)(3)(B); 49 U.S.C. § 60102(b)(6)(C); 49 C.F.R. § 190.311.

requirements should only be waived in circumstances where delaying the rulemaking process would do “real harm”.³³

PHMSA relied on the impracticability prong of the good cause exception in issuing the IFR, stating:

In this instance, the PIPES Act established a 60-day timeline for issuing these temporary or interim emergency-order regulations. This statutory deadline makes notice and comment impracticable, and not in the public interest. The final details of the PIPES Act were not known to PHMSA until after the statute was enacted, and the PIPES Act only affords PHMSA 60 days to issue temporary regulations implementing emergency order authority. Thus, allotting time for notice and public comment (the standard comment period for a notice of proposed rulemaking is 60 days) prior to issuing temporary regulations would thwart PHMSA’s ability to manage the schedule laid out by Congress and impede the due and timely execution of the agency’s functions. Furthermore, section 16 of the PIPES Act directs a specific regulatory outcome—establishing a standard for determining when an emergency order is warranted, identifying particular factors for the agency to consider, and directing the agency to follow specific consultation requirements—for which PHMSA has no discretion.³⁴

The rationale provided in the IFR does not clear the “high bar” for invoking the good cause exception. Regarding the 60-day deadline for establishing the temporary emergency order regulations, the federal courts have repeatedly said that the need to comply with a statutory deadline does not satisfy the good cause exception unless the agency makes the requisite

³³ *Natural Resources Defense Council v. Abraham*, 355 F.3d 179, 205 (2nd Cir. 2004)(citing various cases involving the APA’s good cause exception). As the U.S. Courts of Appeals for the Fourth Circuit recently explained:

We construe the good cause exception narrowly. *United States v. Gould*, 568 F.3d 459, 469 (4th Cir. 2009). There is a high bar to invoke the exception because “[t]he legislative history of the [APA] demonstrates that Congress intended the exceptions in § 553(b)(3)(B) to be narrow ones.” *Nat’l Nutritional Foods Ass’n*, 572 F.2d at 384. Indeed, “Congress expected, and the courts have held, that the various exceptions to the notice-and-comment provisions of section 553 will be narrowly construed and only reluctantly countenanced.” *N.J. Dep’t of Env’tl. Prot. v. EPA*, 626 F.2d 1038, 1045 (D.C.Cir.1980).

As a result, the circumstances justifying reliance on the good cause exception are “rare,” and will be accepted only after a reviewing court “examine[s] closely” the proffered reason for an agency’s deviation from public notice and comment. *Council of the S. Mountains, Inc. v. Donovan*, 653 F.2d 573, 580 (D.C.Cir.1981) (citation omitted). The good cause exception applies only in “emergency situations,” or in cases when delay “could result in serious harm.” *Jifry v. FAA*, 370 F.3d 1174, 1179 (D.C.Cir.2004); see also *Natural Res. Def. Council, Inc. v. Evans*, 316 F.3d 904, 911 (9th Cir.2003) (“[N]otice and comment procedures should be waived only when delay would do real harm.”) (citation and internal quotation marks omitted); *Util. Solid Waste Activities Group*, 236 F.3d at 754 (good cause exception “should be limited to emergency situations”) (citation omitted).

North Carolina Growers’ Ass’n, Inc. v. United Farm Workers, 702 F.3d 755, 767 (2012).

³⁴ 81 Fed. Reg. at 70,982-70,983.

showing of real harm.³⁵ PHMSA did not identify any real harm in its good cause finding and only stated that allowing notice and comment “would thwart PHMSA’s ability to manage the schedule laid out by Congress and impede the timely execution of the agency’s functions.”³⁶ PHMSA made no effort to explain why the agency could not comply with the 60-day deadline in the PIPES Act and the notice and comment requirements in the APA, *e.g.*, by issuing proposed temporary regulations within 30 or 45 days after enactment and providing the public with a shortened 10- or 15-day comment period. That course of action seems entirely reasonable given PHMSA’s statement in the good cause finding that the temporary rulemaking mandate in the PIPES Act “directs a specific regulatory outcome . . . for which PHMSA has no discretion.” Nor did PHMSA point to any real harm that would follow from allowing the public to comment on the temporary regulations before they went into effect. The 60-day statutory deadline had already passed when PHMSA issued the IFR, and there is no indication that the absence of temporary emergency order regulations had prohibited, or would prohibit, PHMSA from taking action to address an emergency situation or imminent harm. The good cause exception in the APA has always allowed, and still allows, PHMSA to take immediate action in such cases.³⁷

GPA Midstream also has several objections to the substantive provisions that PHMSA included in the IFR. The definition of an emergency order does not state that the only restrictions, prohibitions, or safety measures that could be imposed are those necessary to abate the imminent hazard caused by the unsafe condition(s) or practice(s) (or combination thereof). Congress included that limitation in Section 16 of the PIPES Act to ensure that emergency orders would be narrowly tailored and not used to circumvent the ordinary rulemaking and enforcement process. To address these concerns, the definition of emergency order should be revised to state that “*Emergency order* means a written order imposing restrictions, prohibitions, or safety measures on affected entities, but only to the extent necessary to abate an imminent hazard.”

The reference to pipeline safety violations in determining whether an imminent hazard exists should be eliminated. Allowing emergency orders to be issued for pipeline safety violations is inconsistent with the intent of Section 16 and raises significant due process concerns. An operator must have prior notice and the opportunity for a hearing before PHMSA

³⁵ *Natural Resources Defense Council v. Abraham*, 355 F.3d 179, 205 (2nd Cir. 2004) (citing *United States Steel Corp. v. EPA*, 595 F.2d 207, 213-14 & n. 15 (5th Cir. 1979)).

³⁶ 81 Fed. Reg. at 70,983.

³⁷ A brief review of the circumstances where the federal courts have indicated that good cause might exist demonstrates why it was clearly lacking when PHMSA issued the IFR. As the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has explained, good cause to waive the APA’s notice-and-comment rulemaking requirements might exist “if, for example, air travel security agencies would be unable to address threats posing ‘a possible imminent hazard to aircraft, persons, and property within the United States,’ *Jifry*, 370 F.3d at 1179, or if ‘a safety investigation shows that a new safety rule must be put in place immediately,’ *Util. Solid Waste Activities Grp.*, 236 F.3d at 755 (ultimately finding that not to be the case and rejecting the agency’s argument), or if a rule was of ‘life-saving importance’ to mine workers in the event of a mine explosion, *Council of the S. Mountains, Inc. v. Donovan*, 653 F.2d 573, 581 (D.C.Cir.1981) (describing that circumstance as “a special, possibly unique, case”).” *Mack Trucks, Inc. v. E.P.A.*, 682 F.3d 87, 93 (D.C. Cir. 2012). None of the circumstances identified by the D.C. Circuit existed at the time of the IFR. The temporary procedural regulations established in the IFR did not address an actual or threatened emergency, and PHMSA retained the authority under the APA’s good cause exception to take appropriate rulemaking action if such a situation existed (as the D.C. Circuit’s reasoning clearly acknowledges). PHMSA also had the authority to address emergency situations involving individual operators through the issuance of a corrective action order. 49 U.S.C. § 60112.

can find that a violation has been committed under the Pipeline Safety Laws.³⁸ The IFR disregards that fundamental due process protection by allowing PHMSA to make industry-wide findings of violation without providing the affected parties with prior notice or the opportunity for a hearing. PHMSA does not consider violations in issuing corrective action orders to individual pipeline operators,³⁹ and there is no reason to believe that such a finding is appropriate in an emergency order with industry-wide applicability. For these reasons, PHMSA should not reference pipeline safety violations in the regulation for determining whether an imminent hazard exists.

The two-track administrative review process that PHMSA created in the IFR introduces an unnecessary level of complexity and uncertainty and is not consistent with the provisions in Section 16 of the PIPES Act. Section 190.237(c)(2) authorizes the Associate Administrator to issue an administrative decision on the merits of a petition for review without referring the matter to an ALJ if the petitioner does not request a formal hearing, or the Associate Administrator determines that the petition fails to identify any material facts that are in dispute. Nothing in the PIPES Act authorizes the Associate Administrator to take these actions. To the contrary, the PIPES Act specifically affords a petitioner seeking administrative review the right to receive a hearing before an ALJ, and to receive a report and recommendation on the merits of that petition from an ALJ before the Associate Administrator issues a final administrative decision. The informal process created in the temporary regulations allows PHMSA to unilaterally deprive a petitioner of the right to be heard by an ALJ, which is perhaps the primary procedural protection afforded in the PIPES Act, and to render a final administrative decision in a proceeding where PHMSA has already issued an emergency order without providing prior notice or the opportunity for a hearing.

The informal process established in the temporary regulations also introduces an unnecessary layer of administrative complexity and uncertainty, particularly in cases involving multiple petitions for review. If both the formal ALJ process and the informal Associate Administrator process are pursued in a multiple petition scenario, there is a substantial likelihood that conflicting findings could emerge and that the integrity of the administrative process would be compromised without advancing any competing interests. To the extent that PHMSA believes that a mechanism is needed to dispose of certain petitions in a summary fashion, the ALJ can take that action in the formal hearing process. The ALJ is also in a far better position to determine whether and to what extent multiple petitions should be consolidated for administrative purposes. Maintaining a bifurcated process, where PHMSA can refer petitions for formal or informal review and consolidate petitions within or between these two venues, is far less efficient and effective.

GPA Midstream believes that other due process protections should be added to the final emergency order regulations. A prohibition on ex parte communications, and a provision for ensuring separation of functions between PHMSA personnel involved in the development, adjudication, and ultimate decision on a petition, are both necessary. PHMSA's regulations already afford these protections to operators in enforcement cases and they should be extended to emergency order proceedings. A provision allowing interested parties to intervene if a petition

³⁸ 49 U.S.C. §§ 60122-60123.

³⁹ 49 U.S.C. § 60112.

for administrative review of an emergency order is filed should be added as well. Encouraging broader participation by interested parties will ensure that an ALJ has a fully developed record and the benefit of hearing all relevant information and arguments, and entities other than aggrieved pipeline operators, including public interest and industry trade organizations and manufacturers of piping, components, and other equipment, should be entitled to receive intervenor status in cases where it is necessary to protect their interests. Other federal agencies allow interested parties to file motions to intervene in administrative proceedings, and PHMSA should incorporate that right in the final regulations that apply to petitions for review of emergency orders.

4. Reporting Requirements

Specific Reference: 49 C.F.R. §§ 191.3, 195.50, 195.52

Burden Imposed: Not Available

Less Burdensome Alternatives: Increase Monetary Threshold for Estimated Property Damage to Reflect Current Operating Conditions

Entities Affected: Gas and Hazardous Liquid Pipeline Operators

PHMSA's reporting requirements for operators of regulated gas pipeline facilities are codified at 49 C.F.R. Part 191. Part 191 includes requirements for submitting annual, incident, and safety-related condition reports, as well as reports that must be filed before or after certain additional events. PHMSA's reporting requirements for operators of regulated hazardous liquid pipeline facilities are codified at 49 C.F.R. Part 195, Subpart B. Like Part 191, Subpart B requires hazardous liquid pipeline operators to submit annual, accident, and safety-related condition reports, and to file other reports before or after certain additional events.

While GPA Midstream understands PHMSA's need to obtain data, the reporting requirements contain outdated monetary thresholds that are not appropriate for current operating conditions. The incident reporting requirements in Part 191 and the accident reporting requirements in Part 195, Subpart B both use a \$50,000 limitation for estimated property damage as threshold condition for reporting purposes. As many industry commenters noted in a prior rulemaking proceeding, PHMSA established the \$50,000 criteria in the incident reporting requirements for gas pipelines in a 1984 final rule.⁴⁰ If simply adjusted for inflation over time, the current limitation for estimated property damage in that reporting requirement should be more than \$115,000. PHMSA should revise the definition of incident in 49 C.F.R. § 191.3 and the accident reporting requirements in 49 C.F.R. §§ 195.50 and 195.52 to include an increased monetary threshold that accounts for these changes.

5. Industry Standards

Specific Reference: 49 C.F.R. §§ 192.7, 193.2013, 195.3

Burden Imposed: Not Available

Less Burdensome Alternatives: Incorporated Latest Editions of Industry Standards by Reference

⁴⁰ 49 Fed. Reg. 18,960 (May 3, 1984).

Entities Affected: All Owners and Operators of Regulated Gas and Hazardous Liquid Pipeline Facilities

The National Technology Transfer and Advancement Act of 1995 (NTTAA) requires federal agencies to use technical standards that are developed or adopted by voluntary consensus standards bodies, unless doing so would be inconsistent with applicable law or is otherwise impracticable.⁴¹ Consistent with the requirements in the NTTAA, PHMSA currently incorporates by reference all or parts of more than 60 standards and specifications developed and published by standard developing organizations into the federal pipeline safety regulations.⁴² These technical standards cover a wide range of topics, including pipeline transportation, public awareness, welding, underground gas storage, corrosion, and integrity management.⁴³

While there is no specific deadline in the NTTAA for adopting new or revised editions of technical standards, GPA Midstream believes that PHMSA should incorporate the latest edition of a technical standard by reference wherever possible. Relying on obsolete or outdated editions of technical standards creates significant compliance problems, discourages innovation throughout the pipeline industry, and diminishes participation and interest in the standards development process. To avoid these problems, PHMSA should invest additional resources in adopting new or revised editions of technical standards, particularly in cases where a prior edition of a standard is already incorporated by reference. PHMSA should also make a commitment to adopt the latest editions of a technical standard, or provide a decision explaining why it was not adopted, within 1 year of issuance. GPA Midstream believes that taking prompt action to consider the latest edition of technical standards will eliminate unnecessary burdens, encourage innovation, and promote pipeline safety.

6. Retroactive Application of Design Requirements

Specific Reference: Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation, 76 Fed. Reg. 1,504 (Jan. 10, 2011); Pipeline Safety: Verification of Records, 77 Fed. Reg. 26,822 (May 7, 2012); Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Notice of Proposed Rulemaking, 81 Fed. Reg. 20,721, 20,814 (Apr. 8, 2016); Letter from Jeffrey D. Wiese, Associate Administrator for Pipeline Safety, PHMSA, to Mr. Joseph P. Como, Acting Director, Office of Ratepayer Advocates, California Public Utilities Commission (Jan. 23, 2015)

Burden Imposed: \$2.67 to \$3.67 Billion for Pre-1971 Grandfathered Gas Transmission Lines

Less Burden Alternatives: Withdraw or Modify PHMSA Actions to Acknowledge that Design Requirements Do Not Apply Retroactively

Entities Affected: Gas Pipeline Operators

⁴¹ National Technology Transfer and Advancement Act of 1995, Pub. L. 104-113; *See also*, Revised OMB Circular A-119.

⁴² 49 C.F.R. §§ 192.7, 195.3.

⁴³ *Id.*

PHMSA has taken the position in recent years that the design requirements in 49 C.F.R. Part 192 can be applied retroactively to existing pipeline facilities. In a series of advisory bulletins, letters of interpretation, and rulemaking documents issued after the September 2010 gas transmission line incident in San Bruno, California, PHMSA has said that operators must have “traceable, verifiable and complete” design records to substantiate the MAOP of a gas pipeline, and that operators must comply with the tensile strength testing requirements in section 192.107(b) and section II-D of appendix B if these records are lacking.⁴⁴

Despite these recent statements, PHMSA does not have the authority to require operators to use “traceable, verifiable and complete” design records to substantiate the MAOP of a gas pipeline. There are no MAOP-related recordkeeping requirements in Part 192, and the “traceable, verifiable and complete” standard is based on a National Transportation Safety Board (NTSB) recommendation that is not codified in any statute or regulation.⁴⁵ Nor does PHMSA have the authority to require operators of existing pipelines to comply with the tensile strength testing requirements in Part 192. The tensile strength testing requirements are design and initial testing standards, and the Pipeline Safety Laws prohibit PHMSA from retroactively applying such standards to existing pipelines.⁴⁶

Moreover, even if the Pipeline Safety Laws did not have a non-retroactivity provision, the Part 192 tensile strength testing requirements were never intended to apply—and cannot be practicably applied—to in-service gas pipeline facilities.⁴⁷ An operator can only perform tensile

⁴⁴ 76 Fed. Reg. 1,504 (Jan. 10, 2011); 77 Fed. Reg. 26,822 (May 7, 2012); Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, Notice of Proposed Rulemaking, 81 Fed. Reg. 20,721, 20,814 (Apr. 8, 2016); Letter from Jeffrey D. Wiese, Associate Administrator for Pipeline Safety, PHMSA, to Mr. Joseph P. Como, Acting Director, Office of Ratepayer Advocates, California Public Utilities Commission (Jan. 23, 2015). MAOP is the highest pressure that a gas pipeline can experience during normal operation under PHMSA’s regulations. 49 C.F.R. § 192.619. The design pressure of the pipeline is generally one of the factors that must be considered in establishing MAOP. The formula for determining the design pressure of steel pipe is based on the yield strength, nominal outside diameter, nominal wall thickness, design factor, longitudinal joint factor, and temperature derating factor for the pipe. 49 C.F.R. § 192.105. Pipe grade is a critical consideration in the design pressure calculation. When the specification or yield strength of a pipe is not known, the design regulations state that an operator can either conduct tensile strength testing to determine the yield strength using the process prescribed in section I of appendix B, or use a default value of 24,000 p.s.i. for the yield strength in the performing the design formula calculation. 49 C.F.R. § 192.107(b)(2).

⁴⁵ NTSB Safety Recommendations P-10-2, P-10-4, P-10-1 (Jan. 3, 2011).

⁴⁶ The non-retroactivity provision states that PHMSA cannot apply “[a] design, installation, construction, initial inspection, or initial testing standard . . . to a pipeline facility existing when the standard is adopted.” 49 U.S.C. § 60104(b). This prohibition precludes PHMSA from applying the design pressure formula in § 192.105 to pipelines installed prior to the issuance of the federal gas pipeline safety regulations in 1970, including for purposes of establishing MAOP. PHMSA has recognized that principle in interpreting the comparable maximum operating pressure requirements for hazardous liquid pipelines in 49 C.F.R. Part 195. *In the Matter of Belle Fourche Pipeline Company*, Decision on Reconsideration, CPF No. 5-2004-5010 (2009 WL 7810536) (Jul. 15, 2009) (finding that the design pressure limitations in the maximum operating pressure requirements in 49 C.F.R. Part 195 do not apply to any hazardous liquid pipelines in existence prior to the effective of those regulations unless those facilities are replaced, relocated, or otherwise changed); Operating Pressure for Platform Piping; Interpretation, Department of Transportation, Materials Transportation Bureau, Docket No. OPSO-35 (Oct. 15, 1976).

⁴⁷ The tensile strength testing requirements referenced in § 192.107(b) and codified in section II-D of appendix B are based on Section 811 of the 1968 edition of the USA Standard Code for Pressure Piping, Gas Transmission and Distribution Piping Systems, USAS B31.8-1968, the consensus industry standard that DOT relied upon in developing the original federal gas pipeline safety regulations. 35 Fed. Reg. 13,247 (Aug. 19, 1970).

strength testing at the design phase of a project, *i.e.*, when the pipe is separated into individual lengths, located aboveground, and easily accessible for physical examination, inspection, and destructive testing. By taking the position that tensile strength testing must be performed on in-service pipeline facilities, PHMSA is requiring operators to excavate, redesign, and reinstall these facilities as part of an information collection enterprise. Indeed, PHMSA acknowledged that its position was akin to requiring replacement of these pipelines in the April 2016 NPRM for gas gathering and transmission lines.⁴⁸

The potential costs to the pipeline industry from implementing PHMSA's new policy are enormous. In the April 2016 NPRM, PHMSA estimated that the cost of requiring operators of pre-1970 gas transmission line operators to conduct tensile strength testing would be approximately \$2.67 billion to \$3.67 billion over a 15-year period. While staggering, GPA Midstream wishes to note that PHMSA's estimate only reflects the cost of applying the policy to a limited subset of gas transmission line operators who lack "traceable, verifiable and complete" design records. The costs imposed on gas distribution and gathering line operators, who PHMSA says must also comply with the new policy, would be several orders of magnitude higher.

Given the clear absence of legal authority and adverse economic impact, GPA Midstream urges PHMSA to withdraw or modify the new policy supporting retroactive application of the Part 192 design requirements to existing pipeline facilities. PHMSA should reaffirm the longstanding principle that the design pressure limitation in the MAOP regulations does not apply to pipeline facilities installed prior to the applicability of Part 192, and that the tensile strength testing requirements are design and initial testing standards that only apply at the design phase of a pipeline project. As a general rule, PHMSA should provide operators with flexibility in establishing the MAOP of a pipeline. In the event that any required records are not available, operators should be allowed to reestablish MAOP by conducting a new Part 192 pressure test or determining the maximum safe operating pressure in light of the pipeline's history, particularly known corrosion and actual operating pressure. Any other changes in policy should only be implemented in a final rule issued at the conclusion of a notice-and-comment rulemaking proceeding.

7. Recordkeeping

Specific Reference: 49 C.F.R. § 192.603(b); Operations and Maintenance Enforcement Guidance (<https://www.phmsa.dot.gov/pipeline/enforcement/o-m-enforcement-guidance-part-192>); Proposed Part 192, Appendix A.

Burden Imposed: Not Available

Less Burden Alternatives: Withdraw or Modify PHMSA Actions to Acknowledge that There is No General Duty Clause to Maintain Records and § 192.603(b) is Not a Lifetime Recordkeeping Requirement.

⁴⁸ 81 Fed. Reg. at 20,814 ("Under existing regulations, in order for pipelines with insufficient records to maintain operating pressure, operators must excavate the pipeline at every 10 lengths of pipe (commonly referred to as joints) in accordance with section II-D of Appendix B of Part 192 (as specified in §192.107(b)), do a cutout, determine material properties by destructive tensile test, and repair the pipe. The process is similar to doing a repair via pipe replacement.").

Entities Affected: Gas Pipeline Operators

DOT should review PHMSA's Operations and Maintenance Enforcement Guidance for consistency with the pipeline safety regulations. Among other concerns, PHMSA has included an interpretation of the scope of § 192.603(b) in its guidance document that is not supported by the text, structure, or history of the regulation. It is also questionable whether PHMSA obtained the proper approval from the Office of Management and Budget (OMB) to apply § 192.603(b) in such a broad fashion.

Section 192.603(b), a regulation in the operations subpart of the pipeline safety regulations, is a recordkeeping provision limited to those records deemed "necessary to administer the [operating and maintenance] procedures established under [49 C.F.R.] section 192.605."⁴⁹ Pursuant to § 192.605, pipeline operators are required to prepare and follow a manual of written procedures for conducting operations, maintenance, and emergency response activities.⁵⁰ Section 192.603(b) provides that an operator must maintain records deemed necessary to implement this manual.⁵¹ However, in recent years, without notice and comment, PHMSA has attempted to convert § 192.603(b) into a general duty clause to maintain records.

In 1970, when the Agency first codified this provision, it relied on the USA Standard Code for Pressure Piping, Gas Transmission and Distribution Piping Systems (B31.8 or the Standard) in drafting § 192.603(b).⁵² In fact § 192.603(b) was the mirror image of section 850.2 of the Standard. Neither the preamble to the first pipeline safety regulations or the Standard noted that § 192.603(b) was intended as a default, overarching recordkeeping requirement. In the years that followed, DOT consistently advised the industry that the records required were limited to those needed to implement the operations and maintenance manual. For instance, in 1972, the Agency stated that "*If* an operator requires maps as a record to properly administer the operating and maintenance plan to meet the Federal safety requirements, then these maps must be maintained by the operators."⁵³ This interpretation suggests that an operator has the flexibility to determine which records are necessary to administer its own procedures. In 1989, as part of its submission to the Office of Management and Budget (OMB) for approval of a revised information collection, the Agency limited the type of records required under § 192.603(b) as maps, construction records, and operating history.⁵⁴

However, in approximately 2005,⁵⁵ through guidance and without notice and comment, PHMSA expanded the scope of § 192.603(b) by stating that "[w]hen a regulation does not specifically require records, then paragraph § 192.603(b) can be used when appropriate records have not been kept."⁵⁶ This interpretation expands the scope of § 192.603(b) beyond those needed to implement the operations and maintenance manual. There is no support in the text of

⁴⁹ 49 C.F.R. § 192.603(b).

⁵⁰ 49 C.F.R. § 192.605(a).

⁵¹ 49 C.F.R. § 192.603(b).

⁵² Interim Minimum Federal Standards for the Transportation of Natural and Other Gas by Pipeline, 33 Fed. Reg. 16,500 (November 13, 1968); Establishment of Minimum Standards, 35 Fed. Reg. 13,248, 13, 272 (August 19, 1970). *See also*, section 850.2 of ASME B31.8 (1968).

⁵³ PI-72-031 (July 17, 1972).

⁵⁴ <https://www.regulations.gov/document?D=PHMSA-2015-0063-0003> at 20.

⁵⁵ The 2005 Enforcement Guidance was released publicly in 2010.

⁵⁶ PHMSA Code Compliance Guidelines (2005), at 35.

§ 192.603(b) or the regulatory history for this position. In 2016, the Agency proposed a new general duty recordkeeping requirement as part of the Gas Transmission NPRM.⁵⁷ The Agency proposed that “[e]ach operator must make and retain records that demonstrate compliance with this part.”⁵⁸ Although the need for this proposal will be evaluated through the rulemaking process, it calls into question the Agency’s prior interpretation of § 192.603(b). If the Agency already had broad recordkeeping authority in § 192.603(b) as stated in the Guidance, then there would be no need for this latest proposal.

It is also questionable whether PHMSA obtained the proper information collection approvals from OMB to apply § 192.603(b) so broadly. According to the available records on OMB’s website, PHMSA has sought renewal of its information collection authority for gas transmission pipeline records on a regular basis dating back to at least 1984.⁵⁹ At no time, did PHMSA characterize § 192.603(b) as a broad, default recordkeeping requirement. In fact, in the 2008, 2012, and 2015 submissions to OMB, PHMSA characterized § 192.603(b) as a “one-time” collection and attributed ten hours per operator to update the records associated with this regulation.⁶⁰ Clearly, the Agency did not intend to apply § 192.603(b) as a default recordkeeping requirement if the assumed paperwork burden was ten hours per operator.

Finally, starting in 2015, PHMSA began characterizing § 192.603(b) as a lifetime recordkeeping requirement.⁶¹ This interpretation is contrary to the text, structure, and history of this regulation and does not align with the Agency’s historical filings to OMB. In 2015, the Agency issued an interpretation in which it stated that “[s]ections 192.517 and 192.603 require that *all records* regarding the pipeline MAOP determination be *kept for the life of the pipeline segment*, including records of pipe properties, pipeline component properties, pressure test records, class location studies, current class location designation, and operating history.”⁶² PHMSA, thereafter, referenced § 192.603(b) as a lifetime recordkeeping requirement in its proposed Appendix A to Part 192.⁶³

There is no support in the regulation or its associated history that § 192.603(b) carries a lifetime retention requirement. Section 850.2(c) of the Standard did not include a specific record retention period. There is no evidence in the rulemaking history that PHMSA or its predecessor agencies altered that approach when it included § 192.603(b) in the pipeline safety regulations. PHMSA issued several interpretations of § 192.603(b) but never characterized that particular provision as requiring operators to keep records for the life of the pipe.⁶⁴

⁵⁷ 81 Fed. Reg. 20,722 at 20,828.

⁵⁸ *Id.*

⁵⁹ OMB Control No. 2137-0049. *See* Records dated between 1981-2016 available on www.reginfo.gov.

⁶⁰ Supporting Statement for OMB 2137-0049 dated September 30, 2008

(https://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=200809-2137-003); Supporting Statement for OMB Control No. 2137-0049 dated January 31, 2012

(https://www.reginfo.gov/public/do/PRAViewDocument?ref_nbr=201110-2137-003); Supporting Statement for OMB Control No. 2137-0049 dated February 27, 2015 9

(https://www.reginfo.gov/public/do/PRAViewICR?ref_nbr=201502-2137-003).

⁶¹ Letter from Jeffrey Wiese to Joseph Como, PHMSA PI-14-0005 (January 23, 2015) at 3.

⁶² *Id.* (emphasis added).

⁶³ 81 Fed. Reg. 20,722 at 20,849.

⁶⁴ *See* PI-72-031 (July 17, 1972); PI-74-0145 (November 6, 1974); PI-83-0101 (January 26, 1983); PI-93-036 (July 15, 1993); PI-93-047 (August 5, 1993).

If it is PHMSA's intention to attach a lifetime retention requirement to the general recordkeeping requirements in § 192.603(b), then the Agency will need to evaluate the burden of doing so under the Paperwork Reduction Act. For decades, PHMSA has included § 192.603(b) as part of its application to OMB for information collection approval of the "Recordkeeping Requirements for Gas Pipeline Operators".⁶⁵ This particular information collection represents PHMSA's general authority to require natural gas pipeline owners and operators to maintain records, make reports, and provide information to the Secretary. GPA Midstream has reviewed the supporting statements submitted to OMB dating back to 2008. In these submissions, PHMSA included a list of recordkeeping requirements that carry a lifetime retention requirement. PHMSA did not characterize § 192.603(b) as a lifetime retention requirement and did not include those paperwork burdens in its submission to OMB.

PHMSA's 2015 interpretation characterizing § 192.603(b) as a lifetime retention requirement should be rescinded as it has no basis in the regulation and does not align with the approvals obtained by OMB. DOT should also revise its PHMSA Operations and Maintenance Enforcement Guidance to ensure that its interpretation of § 192.603(b) is based on a sound reading of the regulations and consistent with its applications for information collection approval.

* * * *

GPA Midstream appreciates the opportunity to submit comments to DOT and participate in the dialogue on streamlining and improving regulation. We offer our continued assistance to DOT as it evaluates comments and remain available to provide additional data or answer questions that DOT may have. If you have questions, please contact me at (202) 279-1664 or by email at mhite@GPAglobal.org.

Sincerely,



Matthew Hite
Vice President of Government Affairs
GPA Midstream Association

Enclosures (3)

⁶⁵ OMB Control No. 2137-0049.

Attachment 1:

Gas Processors Association January 20, 2012 Comment Letter

Advance Notice of Proposed Rulemaking, Docket No. PHMSA-2011-0023



Via Electronic Filing

January 20, 2012

DOT Docket Management System
U.S. Department of Transportation
West Building Ground Floor, Room W12-140
Docket # PHMSA-2011-0023
1200 New Jersey Avenue, SE
Washington, DC 20590

Re: Advance Notice of Proposed Rulemaking, Pipeline Safety: Safety of Gas Transmission Pipelines, Docket No. PHMSA-2011-0023 – Comments of Gas Processors Association

The Gas Processors Association (GPA) respectfully submits the attached comments to the Pipeline and Hazardous Materials Safety Administration (PHMSA) on the Advanced Notice of Proposed Rulemaking (ANPRM), Pipeline Safety: Safety of Gas Transmission Pipelines.¹ GPA appreciates the opportunity to comment and the additional time that PHMSA provided to submit comments.² GPA is the leading non-profit trade association for the mid-stream industry. GPA is made up of approximately 130 corporate members, all of whom are engaged in the processing of natural gas into merchantable pipeline gas, or in the manufacture, transportation, or further processing of liquid products from natural gas. GPA's membership accounts for approximately 92% of all natural gas liquids produced by the midstream energy sector in the United States. Our members also produce, gather, transmit, and market natural gas and natural gas liquids, and include a number of Canadian and international companies that produce natural gas liquids on a global scale.

GPA appreciates the efforts of other trade associations, including the Texas Pipeline Association, in which many GPA members also participate, in filing responses to all of the ANPRM questions. Given our focus on gathering, GPA has limited its responses to section O of the ANPRM regarding gas gathering pipelines.

GPA commends PHMSA's oversight of the safety of our nation's gas pipelines. The efforts of PHMSA and our industry have resulted in a remarkable safety record for the pipelines that bring natural gas to market for American consumers. The recent, dramatic increase in our ability to produce gas resources here in the United States reduces our dependence on foreign energy imports and creates much-needed jobs at home. With this increase in domestic production and the resulting build-out of a new generation of gas gathering infrastructure, the focus of GPA members on safely moving this resource has never been greater.

¹ Pipeline Safety: Safety of Gas Transmission Pipelines, Advance Notice of Proposed Rulemaking, 76 Fed. Reg. 53,086 (Aug. 25, 2011).

² Extension of Comment Period, 76 Fed. Reg. 70,953 (Nov. 16, 2011).



Gas gathering lines are currently regulated according to the risk they pose to the public. Gathering pipelines in Class 2, 3 and 4 locations are subject, to a varying degree, to PHMSA's Part 192 requirements, depending on their material, stress level, and location. Lines with a higher stress level in more populated areas are subject to most Part 192 requirements and lines with a lower stress level in less populated areas are subject to a smaller subset of Part 192 requirements. While operators periodically survey all of their gathering lines for class location changes, PHMSA does not regulate gathering lines in Class 1 areas. This model makes sense because it allows gathering pipeline operators to focus their resources on those portions of their facilities near to where people live or congregate.

GPA believes that PHMSA should continue its risk-based approach to the safety regulation of gathering pipelines, and should carefully collect and assess more information before changing any substantive regulations. To that end, GPA members believe that PHMSA should take a two-phased approach to its continued oversight of gathering pipelines.

First, PHMSA should complete the gathering study required under Section 21 of the recently enacted Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. This is an essential prerequisite before PHMSA can appropriately change any substantive gathering regulations.³ GPA is committed to work with PHMSA in this regard. GPA will establish a member working group tasked with coordinating with PHMSA to determine the proper metrics and appropriate level of detail for information collection.

Section 21 requires PHMSA to "review existing Federal and State regulations for gas and hazardous liquid gathering lines located onshore and offshore..." and, by January 3, 2014, to report to Congress on the results of this review, and provide recommendations on:

- “(A) the sufficiency of existing Federal and State laws and regulations to ensure the safety of gas and hazardous liquid gathering lines;
- (B) the economic impacts, technical practicability, and challenges of applying existing Federal regulations to gathering lines that are not currently subject to Federal regulation when compared to the public safety benefits; and
- (C) subject to a risk-based assessment, the need to modify or revoke existing exemptions from Federal regulation for gas and hazardous liquid gathering lines.”

Second, after PHMSA has collected and analyzed sufficient information and completed the Section 21 study, only then should PHMSA determine whether changes to the regulations covering gathering should be considered. If PHMSA determines such consideration is warranted, it should issue a gathering pipeline-focused ANPRM to solicit input on what, if any, additional safety regulation is appropriate for these pipelines.

³ Pub. L. 112-90, 125 Stat. 1904 (Jan. 3, 2012). The language of section 21 that requires PHMSA to submit its study recommendations to Congress, strongly suggests that Congress did not intend for PHMSA to make substantive changes to the gathering regulations until after the recommendations are submitted and Congress has an opportunity to review them.



O.1. Should PHMSA amend 49 CFR Part 191 to require the submission of annual, incident, and safety-related conditions reports by the operators of all gathering lines?

PHMSA currently requires annual, incident and safety-related condition (SRC) reporting under 49 CFR Part 191 for gathering pipelines in Class 2, 3 and 4 locations, and subjects these lines to a range of Part 192 safety requirements. Only rural, Class 1 gathering pipelines are not subject to PHMSA's reporting and safety requirements. GPA is committed to working with PHMSA to identify the appropriate metrics and information to enable industry and the agency to make risk-informed judgments about the future oversight of Class 1 gathering. This continues GPA members' longstanding commitment to provide information about their gathering lines.

In 2003, GPA aggregated data from member companies and from other trade associations regarding the five-year incident history of rural gathering lines, in an effort to develop evidence on the safety record of these lines.⁴ The survey demonstrated the strong safety record of these pipelines and showed that rural gathering lines were three to six times less likely to impact the public than transmission lines.⁵ These survey results served as part of the foundation for developing the regulatory framework in place today. PHMSA also conducted a web-based discussion forum, followed by two public meetings to collect information on the risks of gathering lines.⁶ After considering the information received at these meetings and from numerous written comments, PHMSA decided not to expand Part 192 requirements to rural, Class 1 gathering lines.

GPA recognizes that there has been an expansion in domestic gas gathering infrastructure since the 2003 survey. As a result, and as stated above, GPA is committed to working with PHMSA to determine the proper metrics and appropriate level of detail for the collection of information on Class 1 gathering. In time, as PHMSA collects and analyzes information on Class 1 gathering, operators and PHMSA will be able to evaluate the adequacy of current gathering regulations in a meaningful way. GPA believes that PHMSA can obtain the information necessary to undertake this evaluation without amending Part 191.

Regarding SRC, incident and annual reporting requirements, GPA does not support expanding Part 191 requirements to Class 1 gathering lines at this time. The current annual and incident report forms require detailed pipe information and statistics that may not be available for many Class 1 lines, as gathering companies have never been required to keep records for these lines. Similarly, SRC reporting is not appropriate for Class 1 gathering lines. The purpose of SRC reporting is to provide notice to PHMSA so that it can become involved in remedial actions for certain pipeline conditions in which no incident or failure has occurred. SRC reporting for Class 1 gathering lines would be premature at this time.

⁴ Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards, 71 Fed. Reg. 13,289, 13,290 (Mar. 15, 2006).

⁵ *Id.*

⁶ *Id.* at 13,291.



O.2. Should PHMSA amend 49 CFR part 192 to include a new definition for the term “gathering line”?

Note, GPA has grouped Questions O.2, O.3 and O.5 together as they are all related to the definition of gathering or regulated onshore gathering.

Current PHMSA regulations define a gathering line as “a pipeline that transports gas from a current production facility to a transmission line or main.”⁷ This relatively simple definition is only the starting point in the analysis of whether a pipeline is regulated and to what extent. If a pipeline meets the basic Part 192 definition of gathering line, an operator then applies 49 CFR § 192.8(a) and the API RP 80 standard incorporated by reference into the regulation, to determine whether the pipeline is an “onshore gathering line.” This process involves the application of the RP 80 standard, and the gathering start and endpoint limitations set out in 49 CFR § 192.8(a). If this analysis demonstrates that the pipeline is an onshore gathering line, then an operator must apply 49 CFR § 192.8(b) to determine whether the line is a “regulated onshore gathering line,” and if so, whether it is a Type A or B regulated onshore gathering line. Once this classification is established, an operator then turns to 49 CFR § 192.9 to determine what Part 192 requirements apply to the line.

GPA believes that before considering whether to amend the regulatory definition of gathering line, that PHMSA must first collect and analyze information on Class 1 gathering lines and complete the gathering study required by Section 21 of the 2011 Act. As indicated in our response to O.1, GPA is committed to working with PHMSA to identify the proper metrics and information on Class 1 lines. This information is crucial to understanding the safety issues Class 1 gathering lines face and whether the current regulatory structure, including the definitions, is sufficient.

GPA again notes that the basic 49 CFR § 192.3 definition of gathering line represents only one part of the gathering equation. This definition is linked to the definitions of distribution and transmission and serves as the backdrop for the onshore gathering analysis under RP 80. Therefore, any future change in the basic regulatory definition of gathering must consider the regulatory framework as a whole, in order to avoid unintended consequences.

O.3. Are there any difficulties in applying the definitions contained in RP 80? If so, please explain.

The complexity of many gathering systems and the interpretations and guidance PHMSA has issued, have led to some challenges in applying RP 80. However, despite these challenges, industry has adapted to the RP 80 framework and, since 2006, a body of knowledge has been developed on which industry can draw to apply the standard. Moreover, identifying a simpler definition of onshore gathering has proven difficult.

⁷ 49 C.F.R. § 192.3.



Until PHMSA collects additional information and completes the Section 21 gathering study, it would be premature to revise the current RP 80 framework. Any changes to gathering regulation, including the definition of what is covered by those regulations, should be considered only if necessary on the basis of additional information and the Section 21 gathering study.

O.5. Should PHMSA consider short sections of pipeline downstream of processing, compression, and similar equipment to be a continuation of gathering? If so, what are the appropriate risk factors that should be considered in defining the scope of that limitation (e.g. doesn't leave the operator's property, not longer than 1000 feet, crosses no public rights-of-way)?

GPA believes that PHMSA regulations should recognize the practical realities of field operations and that PHMSA should consider short sections of pipeline downstream of processing, compression, and similar equipment to be a continuation of gathering.⁸ Many processing plants and compressors cannot be located immediately adjacent to a transmission line because of population or inadequate available space for the facility. Pipelines downstream from a processing plant or a gathering compressor should be considered gathering. This would clarify the ambiguity in the regulations and prevent the unnecessary regulation of these sections of pipeline as transmission lines.

Furthermore, the pipelines downstream from these facilities typically transport clean, dry gas to nearby transmission pipelines. If such pipelines are treated as gathering, they will be subject to PHMSA regulations if they are located in more populated Class 2, 3, or 4 areas. Thus, treating these lines as gathering would not result in a regulatory or safety gap.

If PHMSA considers revisions to the gathering pipeline regulations in the future, it should include a provision that supports the concept of incidental gathering pipelines. GPA believes that incidental gathering lines should be subject to the same regulatory framework as other regulated gathering pipelines. GPA welcomes the opportunity to work with PHMSA on the specifics of the incidental gathering concept if PHMSA contemplates any regulatory changes after it collects additional information about gathering lines and performs the Section 21 gathering study.

O.4. Should PHMSA consider establishing a new, risk-based regime of safety requirements for large-diameter, high-pressure gas gathering lines in rural locations? If so, what requirements should be imposed?

GPA believes that PHMSA must collect additional information on Class 1 gathering pipelines before it considers establishing new requirements for any of these lines. As discussed in our response to question O.1, GPA is committed to working with PHMSA to identify the proper metrics and information necessary for the agency to make risk-based decisions about whether the

⁸ Under the API RP 80 framework, such lines are often referred to as "incidental gathering." RP 80 section 2.2(a)(1)(E).



future regulatory treatment of Class 1 lines should change. PHMSA also must complete the Section 21 gathering study before considering the expansion of requirements for such lines. The completion of this study will provide PHMSA with information on the role of State gathering regulations, as well as the “economic impacts, technical practicability, and challenges of applying existing Federal regulations to gathering lines that are not currently subject to Federal regulations when compared to the public safety benefits.”⁹ Only with additional study can PHMSA evaluate whether increased regulation of large-diameter, high-pressure rural gathering lines is appropriate and would provide safety benefits warranting the costs associated with expanded regulations.

O.6. Should PHMSA consider adopting specific requirements for pipelines associated with landfill gas systems? If so, what regulations should be adopted and why? Should PHMSA consider adding regulations to address the risks associated with landfill gas that contains higher concentrations of hydrogen sulfide and/or carbon dioxide?

This question is not applicable to GPA members and therefore we respectfully decline to comment.

O.7. Internal corrosion is an elevated threat to gathering systems due to the composition of the gas transported. Should PHMSA enhance its requirements for internal corrosion control for gathering pipelines? Should this include required cleaning on a periodic basis?

Internal corrosion is only one of numerous threats that gathering systems face. According to PHMSA data collected from regulated Class 2, 3 and 4 gathering lines, excavation damage and other outside force damage pose a greater aggregate threat to gas gathering systems than internal corrosion.¹⁰

All pipeline systems, gathering or otherwise, face different threats depending on a host of factors. Internal corrosion may be, but is not always, an elevated threat. GPA believes the existing regulations for corrosion control are adequate to protect gathering lines. Class 2, 3, and 4 gathering lines already must comply with Subpart I corrosion control requirements, including the internal corrosion control requirements in Sections 192.475, 192.476 and 192.477. These regulations provide the flexibility that operators need to achieve corrosion prevention goals, rather than prescribe specific methods or tools that are not appropriate for all lines in all situations. Therefore, GPA believes that PHMSA’s existing internal corrosion control requirements provide appropriate protection for gathering lines. Regarding Class 1 gathering, GPA, again, believes that PHMSA must collect additional information on these facilities before considering expansion of any regulations, including internal corrosion control regulations.

Gathering system operators take significant steps to protect the public, the environment, and the integrity of their systems. Operators’ activities relating to internal corrosion prevention vary

⁹ Pub. L. 112-90, section 21(b)(2).

¹⁰ <http://primis.phmsa.dot.gov/comm/reports/safety/> last accessed Jan. 17, 2012.



depending on operational and other factors. Operators need the flexibility to take these specific operational factors into account when implementing internal corrosion control measures. Mandating the use of specific measures such as maintenance pigging, would require that many gathering systems be unnecessarily modified, potentially making their operation uneconomical.

O.8. Should PHMSA apply its Gas Integrity Management Requirements to onshore gas gathering lines? If so, to what extent should those regulations be applied and why?

GPA respectfully contends that it would be inappropriate to apply IM requirements to gathering lines. The current IM regulations require additional safety protections for certain gas transmission pipelines located in High Consequence Areas (HCA). The IM requirements are in addition to the broader set of Part 192 requirements that apply to all gas transmission pipelines, and, to a varying extent, to regulated gas gathering pipelines. The driving force behind the IM requirements is the concept that some pipelines pose a greater risk to the public than others. For such lines, PHMSA has made the determination that the risks warrant the significant, additional expense of an integrity management program. Transmission industry estimates indicate that the cost of development and implementation of IM programs for transmission pipelines has been several billion dollars since the IM rule was promulgated in 2003. There is currently no evidence that gathering lines pose the level of risk that warrants the expense of IM requirements.

The application of IM to gathering pipelines poses several significant concerns. Gathering lines have not been subject to IM requirements in the past and have not been designed to accommodate the application of this regulatory program. As a result, most gathering lines cannot be assessed with in-line inspection tools. This leaves either hydrostatic testing or direct assessment to evaluate the condition of a gathering pipeline. Hydrostatic testing after a gathering line becomes operational is difficult, expensive and could result in the shut-in of upstream production wells. Well shut-in can have long-term impacts on well productivity, significantly impacting the economics of both the upstream production and gathering line operations. Direct assessment is a data-intensive assessment process that poses challenges for gathering lines that have never been required to collect and maintain such data.

Again, before PHMSA considers any new safety requirements for gathering lines PHMSA must collect additional information on Class 1 gathering lines and also must perform the Section 21 gathering study. Only against the backdrop of information on Class 1 lines and the Section 21 gathering study can PHMSA and industry consider the appropriateness of new rules.

O.9. If commenters suggest modification to the existing regulatory requirements, PHMSA requests that commenters be as specific as possible. In addition, PHMSA requests commenters to provide information and supporting data related to:

- The potential costs of modifying the existing regulatory requirements.
- The potential quantifiable safety and societal benefits of modifying the existing regulatory requirements.
- The potential impacts on small businesses of modifying the existing regulatory requirements.



- **The potential environmental impacts of modifying the existing regulatory requirements.**

At this time, GPA does not believe any regulatory changes are necessary or appropriate. After PHMSA collects and reviews more information and undertakes the Section 21 gathering study, GPA stands ready to provide specific ideas on solutions, where solutions are necessary. GPA looks forward to working with PHMSA toward our shared goal of the safety of America's gas gathering infrastructure.

Farm Taps

Some GPA member companies have farm taps attached to gathering lines. We understand that members have reached out to PHMSA to resolve concerns about how these farm taps are classified and how the Part 192 gas pipeline safety regulations may apply to them. GPA supports these efforts and welcomes the opportunity to work with PHMSA to resolve these issues.

Conclusion

GPA appreciates the opportunity to provide our comments on the ANPRM. Thank you, in advance, for your consideration of them.

Respectfully submitted,

GAS PROCESSORS ASSOCIATION

By:

A handwritten signature in black ink that reads "Jeff Applekamp".

Jeff Applekamp

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cc: Cynthia Quarterman, Administrator, PHMSA
Jeffrey Wiese, Associate Administrator for Pipeline Safety, PHMSA

Attachment 2:

GPA Midstream Association July 7, 2016 Comment Letter

Notice of Proposed Rulemaking, Docket No. PHMSA-2011-0023



VIA ELECTRONIC FILING

July 7, 2016

U.S. DOT Docket Management System
West Building Ground Floor
Room W12-140
1200 New Jersey Avenue, SE,
Washington, DC 20590-0001
DC 20590-0001

Re: Docket No. PHMSA 2011 – 0023: Proposed Rule on Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines; Federal Register Vol. 81, No. 68 (Friday, April 8, 2016); RIN 2137-AE72

The GPA Midstream Association (“GPA Midstream” or the “Association”) appreciates the opportunity to provide comments in response to the Pipeline and Hazardous Materials Safety Administration’s (“PHMSA”) Notice of Proposed Rulemaking (“NPRM” or “Notice”) on the Safety of Gas Transmission and Gathering Pipelines.¹ GPA Midstream members own and operate hundreds of thousands of miles of gathering lines which represent over 90 percent of all gathering lines in the US.”

GPA Midstream has served the U.S. energy industry since 1921 as an incorporated non-profit trade association. GPA Midstream is composed of over 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. GPA Midstream members account for more than 90 percent of the NGLs produced in the United States from natural gas processing.

On August 25, 2011, PHMSA published an Advance Notice of Proposed Rulemaking titled “*Pipeline Safety: Safety of Gas Transmission Pipelines*”.² GPA Midstream filed comments on January 20, 2012, and limited the focus of its comments at that time to Section “O” related to onshore gas gathering. In addition, many of its member companies are also members of Texas

¹ *Pipeline Safety: “Safety of Gas Transmission and Gathering Pipelines,”* Notice of Proposed Rulemaking, 81 FR, 20722 (April 8, 2016)

² 76 FR 53086 - 53102

Pipeline Association (“TPA”) and participated in the development of the comments submitted on behalf of their Association.

PHMSA published the NPRM on April 8, 2016, proposing substantial revisions to the Pipeline Safety Regulations applicable to the safety of onshore gas transmission and gathering pipelines. Most notably for GPA members, the NPRM proposes to expand the regulation of onshore gas gathering lines to impose new reporting requirements on rural gathering pipelines, and to extend the definition of regulated gathering to encompass Type A gathering lines in Class 1 locations with a diameter of 8 inches or greater, and a maximum allowable operating pressure (“MAOP”) equal to or greater than 20% of specified minimum yield strength (“SMYS”).

GPA Midstream is concerned that some of the proposed requirements in the Notice may go beyond or be inconsistent with PHMSA’s statutory authority under Title 49 USC 60101 *et seq.*,³ whether or not PHMSA has adequately justified its proposal on the basis of risk or public opinion. Where GPA Midstream identifies this issue, GPA Midstream will comment on the nature of the objection and ask PHMSA to clarify or to modify its proposal.

GPA Midstream members have a significant interest in all aspects of the NPRM. GPA Midstream has provided comments in greatest detail for those provisions that pose the greatest burden to its membership as well as PHMSA and state partner agencies but which are likely to result in little or no safety benefit, and those provisions that may be impracticable to implement. Further, based on our analysis of member information, GPA Midstream is confident the actual total cost of the proposal far exceeds the \$47 million plus per year cost to industry asserted by PHMSA. In some instances, PHMSA has offered little, if any, evidence to show that the proposed changes are reasonable or necessary. For other provisions of the proposed regulations, GPA Midstream states its support or requests additional clarification on a particular issue to be included in the final rule.

A. General Comments on Rulemaking.

GPA Midstream members are committed to the safety of the nation’s gas gathering pipelines. While GPA Midstream is opposed to several of the provisions as proposed, we are committed to working with PHMSA to make changes to the regulations that allow for common-sense, risk-based requirements for the midstream sector. GPA Midstream members are open to changes in the regulations for gathering pipelines to address the substantial infrastructure build-out that has occurred in the last several years. However, GPA Midstream is concerned that PHMSA’s proposals are not based on evidence or the actual risk posed by gathering pipelines. The Pipeline Safety Laws set out a framework that PHMSA must follow when changing its gathering line regulations. This statutory framework requires PHMSA to regulate gathering lines based on risk, as evidenced by data collected from gathering operators. GPA Midstream is

³ 49 U.S.C. §60101 *et seq.*

concerned that PHMSA's current proposals are not consistent with the statutory framework, including the provisions of the 2011 Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (the 2011 Act).⁴ GPA Midstream members are willing to commit resources to implement lawful and appropriate changes in gathering regulations, but our members are not in a position to do so where the changes in regulation are not based on risk, and would not provide a meaningful safety benefit.

The statutory scheme sets out an orderly process for PHMSA's consideration of whether and how to subject additional gathering lines to federal regulation. First, PHMSA must collect appropriate data about those pipelines to determine the risks they may pose. Second, after collecting data, PHMSA must consider specific physical and operational characteristics in making a determination of whether and what extent to regulate additional gathering lines. Third, PHMSA must comply with a series of rulemaking requirements designed to ensure that its regulations are practicable. Finally, the 2011 Act required PHMSA to study gathering line regulations nationwide, and then issue a report of its findings and recommendations, in light of specific factors, to Congress.

1. Changes Based on Risk Data

In the early 1990's Congress amended the pipeline safety laws to require PHMSA to define gathering and regulated gathering, and to allow limited regulation of rural gas gathering pipelines if appropriate.⁵ In support of this requirement, Congress included a provision to allow PHMSA to "require owners and operators of gathering lines to provide [PHMSA] information pertinent to [PHMSA's] ability to make a determination as to whether and to what extent to regulate gathering lines."⁶ This language was included so that PHMSA would only regulate rural gathering lines to the extent appropriate based on information collected about them. In the legislative history for the 1992 amendments, Congress observed "[PHMSA] should 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."⁷

⁴ PL 112-90, Jan. 3, 2012.

⁵ 49 U.S.C. § 60101(b).

⁶ 49 U.S.C. § 60117(b)(2).

⁷ H.R. REP. 102-247(I), 1992 U.S.C.C.A.N. 2642, 2653.

PHMSA has not exercised this information collection authority, but is nonetheless moving forward with significant proposed changes to the regulations. The agency has included no safety data pertaining to gathering pipelines in the record to justify its proposed changes to either the definition of an onshore gas gathering line or its proposed criteria for regulating certain rural gathering lines.⁸ In contrast, in PHMSA's parallel rulemaking proceeding for hazardous liquids pipelines, the agency has elected to follow the statute and collect more data about currently unregulated rural gathering lines before deciding whether and how to change the regulations to cover them.⁹ There is no rational basis for PHMSA to move forward with a data collection in an essentially parallel gathering line rulemaking but skip it here.

2. Consideration of Specific Statutory Factors

When PHMSA prescribes a new definition for a "gathering line," the statute requires the Agency to "consider functional and operational characteristics of the lines to be included in the definition."¹⁰ PHMSA must also consider certain factors in determining whether to regulate gas gathering lines, including "location, length of line from the well site, operating pressure, throughput, and the composition of the transported gas . . ."¹¹ As further discussed in GPA Midstream's specific comments on the proposed rule, PHMSA has proposed to regulate rural gathering lines of 8-inches in diameter or greater and operated above 20% SMYS or 125 psig, but it has provided no explanation of why it is appropriate to select those thresholds and presented no data to show that those thresholds are reasonable thresholds above which gathering lines should be regulated because of specific physical characteristics.

3. PHMSA Must also Consider General Rulemaking Factors Before Changing its Gathering Line Regulations

When prescribing any standard applicable to regulated gathering lines, PHMSA must consider certain generally-applicable factors, including all relevant available gas pipeline safety information and environmental information, the of the standard for the particular type of pipeline

⁸ NPRM at 20,801-20,808. Also cite PHMSA's statements during the June 8, 2016 webinar.

⁹ 80 Fed. Reg. 61,610, 61,617.

¹⁰ 49 U.S.C. § 60101(b)(1).

¹¹ 49 U.S.C. § 60101(b)(2).

facility, the reasonableness of the standard, the reasonably identifiable or estimated costs and benefits of a proposed standard (based upon a risk assessment), and the comments and information received from the public.¹² Any such standard must also “designed to meet the need for gas pipeline safety...”¹³ PHMSA has not explained either how it considered these required statutory factors or how it determined the proposal is reasonable and appropriate.

While PHMSA has provided information about costs and benefits in its Preliminary Regulatory Impact Analysis (“RIA”), the predicate risk assessment required by the statute is nowhere to be found.¹⁴ It appears that PHMSA has either instead substituted a “Regulatory Analysis” in Section 2 of the RIA as a proxy for any meaningful risk assessment, or simply ignored that mandate altogether. Either way, in many cases the cost and benefit information set forth in the RIA does not accurately account for the impacts on gathering lines or demonstrate what safety benefit would be realized under the proposal.¹⁵

4. **Gathering Recommendations and Factors Required by the Gathering Provision of the 2011 Act.**

The 2011 Act required PHMSA to review federal and state gathering regulations and report the results of that review to Congress by January 2014, along with recommendations on whether existing regulations were sufficient.¹⁶ In making recommendations, PHMSA was required to consider the “economic impacts, technical practicability, and challenges of applying existing Federal regulations to gathering lines that are not currently subject to Federal regulation when compared to the public safety benefits.”¹⁷ PHMSA was also required to consider, “subject to a

¹² 49 U.S.C. § 60102(b)(2).

¹³ 49 U.S.C. § 60102(b)(1).

¹⁴ See 49 U.S.C. § 60102(b)(2)(D), (E).

¹⁵ Preliminary Regulatory Impact Assessment (March 2016). PHMSA used estimated costs obtained in 2004 adjusted for inflation. PHMSA failed to account for increased expectations for many of the programs, such as performance evaluations for public awareness programs and outreach to emergency response community. PHMSA has not accounted for the expansion of Operator Qualification programs to the proposed regulation of gathering lines in Class 1 location in this RIA or in the RIA developed for the Miscellaneous II regulation (Vol. 80 Friday, No. 132 July 10, 2015)

¹⁶ Pub. L. 112-90 Sec. 21.

¹⁷ Sec. 21(b)(2)(B).

risk-based assessment, the need to modify or revoke existing exemptions from Federal regulation for gas ... gathering lines.”¹⁸

In May 2015, PHMSA delivered a report to Congress on the regulation of gas gathering lines. That report, apparently completed in September 2013, summarized existing federal and state regulations for gathering lines. The report did not provide any analysis of the adequacy of those regulations or make the required recommendations to Congress on the need for future action. In the letters transmitting the study to members of Congress, PHMSA committed to develop recommendations and consider the statutory factors in its rulemaking proceedings.¹⁹ Yet, PHMSA states in the NPRM that the report was not considered in developing any of the proposed modifications to the gathering rules.²⁰

The 2011 Act set out Congress’ expectation that PHMSA would carefully consider the issue and make recommendations to Congress before subjecting additional lines to federal regulation. PHMSA has not done so here, and has failed to consider the additional, important factors in the 2011 Act for determining the appropriateness of future gathering regulation.

Based on the inadequacies in the proposed rulemaking with respect to PHMSA’s statutory obligations, GPA Midstream requests that PHMSA withdraw its proposed changes to the gathering line regulations and modify its proposal to collect data on the risks posed by gathering pipelines. Only on an analysis of that data can PHMSA develop proposals that are practicable, risk-based and consistent with the Pipeline Safety Laws. Although GPA Midstream believes that PHMSA should address these substantive issues before proposing any new requirements for gathering pipelines, GPA Midstream is willing to consider certain of PHMSA’s proposals, with modifications. GPA Midstream’s specific comments on the proposed gathering comments are set out below.

¹⁸ Sec. 21(b)(2)(C)

¹⁹ Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Gathering Lines transmitted to Congress May 8, 2015 (Gathering Report). The report was required by the Section 21 of the 2011 Act which required PHMSA to shall conduct a review of existing Federal and State regulations for gas and hazardous liquid gathering lines, report to Congress on the sufficiency of existing Federal and State laws and regulations to ensure the safety of gas and hazardous liquid gathering lines, and provide recommendations regarding the economic impacts, technical practicability, and challenges of applying existing Federal regulations to gathering lines that are not currently subject to Federal regulation when compared to the public safety benefits.

²⁰ As required by Section 21 of the 2011 Act, PHMSA transmitted copies of the Gathering Report to the Committee on Transportation and Infrastructure and the Committee on Energy and Commerce of the House of Representatives and the Committee on Commerce, Science, and Transportation of the Senate. Each Chair and Ranking member received a cover letter in which PHMSA stated it was reviewing the need to propose changes and said review would be risk-based and would take into account economic impact, technical practicability, and the challenges of applying any proposed regulations on gathering lines that are not currently regulated.

A. Changes to Reporting Requirements—Part 191

PHMSA is proposing to amend 49 CFR, Part 191 Transportation of Gas by Pipeline: Annual Reports, Incident Reports, and Safety-Related Condition Reports. PHMSA is proposing that operators of regulated and non-regulated gathering lines comply with the reporting requirements in Part 191, with the exception of submission of data to the National Pipeline Mapping System (“NPMS”).

First, PHMSA is proposing in section 191.1(a) to extend the reporting requirements in Part 191 to all pipeline facilities, including regulated and non-regulated onshore gas gathering, with certain exceptions as set forth in section 191.1(c). PHMSA does not address whether it has the statutory authority to require reporting for non-regulated gathering pipelines to the extent it has proposed, which are by definition excluded from the scope of the pipeline safety laws set forth under 49 USC 60101 et seq. In addition, the only exemptions from Part 191 are set forth in section 191.1(c), which provides that pipelines operated at less than 0 psig, that are not otherwise regulated as determined under §192.8, or that are located in inlet waters to the Gulf of Mexico are not required to obtain OPID Validation pursuant to §19.22(b) or to submit NPMS data pursuant to section 191.29. Even the limited scope of those exemptions are inconsistent with proposed section 191.29, which excludes all gathering pipelines from the NPMS, and with 49 U.S.C. §60132(a), which provides a parallel statutory exclusion from the NPMS for all gathering lines. PHMSA should clarify in the final rule that all gathering pipelines are excluded from the NPMS.

Further, PHMSA should clarify that newly regulated Type A, Area 2 gathering lines are exempt from the requirements of both §§191.22(b) and (c). In the RIA (Table 3-94), PHMSA indicates that changes as described in §191.22(c) would be reported per event. Since Table 3-95 depicts §191.22(c) as being not applicable to non-regulated gathering, GPA Midstream assumes PHMSA intended to exclude National Registry Reporting Requirements for non-regulated gathering. The rule language proposed in §191.1(c) does not include an exemption for non-regulated gathering from reporting obligations under §191.22(c). GPA Midstream sees no value in reporting these activities to PHMSA. Assuming it is new pipe being installed, the data will be present on the operator’s next annual report.

Second, PHMSA does not distinguish between regulated and non-regulated lines in requiring operators to report safety-related conditions, which include exceedances of MAOP. It is not clear from PHMSA’s analysis that reporting of safety-related conditions on non-regulated gathering lines, even if technically feasible, offers sufficient safety benefits relative to the practicability and cost of compliance. Nor does PHMSA offer an explanation of how reporting MAOP exceedances on newly-regulated or unregulated gathering lines is consistent with PHMSA’s statutory authority, both as to extension of regulation to unregulated pipelines and as to the imposition of standards that were inapplicable prior to the effective date of the proposed regulation. This is especially important because PHMSA has defined safety related conditions

to include exceedances of MAOP on all gathering pipelines in proposed § 191.23(a)(5). By doing so, PHMSA has in effect required operators of both newly-regulated Class 1 gathering pipelines and non-regulated Class 1 gathering pipelines to establish MAOP for all such pipelines in order to comply with the reporting requirements of Part 191. To emphasize the significance of this proposal, in order to comply with this reporting requirement, every operator would be required to establish or confirm the MAOP of what PHMSA estimates to be approximately 239,000 miles of Class 1 gathering lines not previously subject to regulation, including requirements to establish MAOP or maintain records needed to establish MAOP. PHMSA has not included the cost of this predicate compliance task in the RIA, but such cost could dwarf the costs PHMSA estimated for reporting in the RIA.

For example, even if operators are allowed to use operating history records to establish the MAOP of gathering lines for which they do not have design, construction, and testing records, pursuant to 192.619(c), operators of Class 1 gathering pipelines may not have complete pressure history records for these pipelines, because such Class 1 lines have not previously been subject to Part 192. Assuming acceptable records are available for 50% of all mileage subject to the reporting requirements, and using PHMSA's per mile cost to pressure test 12" intrastate pipe (for simplification) in 5-mile segments (RIA Table 3.18, page 44), the cost would exceed \$14,000,000,000 (\$14 billion) if the standards to substantiate MAOP proposed in §§192.607 and 192.624 are expected. While the occurrence of safety-related conditions on gathering pipelines will be relatively infrequent, the costs associated with documenting the MAOP of all gathering pipelines are very real and have not been taken into consideration in evaluating the appropriateness of proposed §§ 191.1(a) and 191.23.

While the data and cost associated with the actual filing of the report are included in the analysis, GPA Midstream believes PHMSA has neglected to account for the costs and burden associated with the initial compiling of the data needed to complete the forms. In many cases, the information may not be recorded or may not have been provided during mergers or acquisitions, and where it is available it is likely stored in "project" files. Extracting the data will be a manual process requiring thousands of hours. PHMSA has not communicated its expectations for these situations. GPA Midstream believes any requirement to have reliable, traceable, verifiable, and complete ("RTVC") records for gathering pipelines constructed prior to the effective date of the final rule grossly exceeds that the plain language and the congressional intent of Section 23 of the Act, which expressly applies to gas transmission pipelines in Class 3 and 4 locations, and Class 1 and 2 High Consequence Areas ("HCAs"). If it is PHMSA's expectation that operators physically excavate to obtain the data, as set forth in the proposed new §§192.607 and 192.624, the costs will reach into the hundreds of millions.

Third, although PHMSA has identified in the RIA the "One Time" costs associated with all of the data reporting activities in Part 191 to reflect the adjusted burden hours needed to comply with the proposal, PHMSA has grossly underestimated those costs. We concur with PHMSA that reporting Safety-Related Conditions and incidents are event driven and very

difficult to project the number of occurrence per year. However, the assumed “One Time” costs tabulated in Section 3.8.3.4.4 of the RIA do not reflect the actual programmatic costs incurred by operators to add previously unregulated pipeline mileage to the reporting system. PHMSA has assumed that simply because an operator has regulated mileage already, it will not incur any programmatic costs to roll up the mileage not previously reported. Operators currently filing Annual Reports {7100.2.1, OMB No. 2137-0522} that also have gathering that is not currently regulated will experience increased costs and burden to collect data from the “field” and incorporate it into the reporting management process. As PHMSA notes, this entails data for some 332,000 miles of pipeline. The largest burden will be incurred the first year, but there will be associated costs each year as systems are expanded or pipe is replaced or abandoned. PHMSA has estimated a one-time cost of \$5.06 per mile for Group 2 operators, those that currently have regulated mileage, to report newly-regulated Type A, Area 2 gathering lines (RIA Table 3-99). First, we believe this number to be low because it does not take into account the costs to assemble the information into formats suitable for incorporation into report forms. Second, the report(s) included in this one-time cost are the same reports that will be required for the remaining non-regulated 266,526 miles. The costs for those will be the same, not the \$0.08 per mile PHMSA has estimated. This places the costs at \$1,348,621 and not the \$22,500 as estimated. It is logical that the Group 1 operator costs are also underestimated based on this same analysis.

Also, PHMSA has not recognized that exploration activities greatly influence the amount of new pipe that is installed each year in gathering applications. As such, when commodity prices make drilling cost effective, the increased activity will cause more burden hours used to file each report, unlike the more stable mileage numbers associated with transmission. These changes obviously affect the projected 15-year annualized figures as well as the overall cost to benefit ratio, which is already negative on the benefit side for the gathering line proposals.

Finally, the GAO²¹ report recommended that data collection be conducted “subsequent to an analysis of the benefits and industry burdens associated with such data collection.” GPA Midstream supports PHMSA’s goal of collecting data necessary to make informed rulemaking decisions, but believes that this can be accomplished by developing an abbreviated annual reporting form which includes only the data contained in Sections A, C, D, I, J (gathering only), L (gathering only), & the M1 data fields (gathering only) from the Gas Transmission Annual Report (F7100.2-1). The information collected annually through this process could then be paired with Incident reporting on Form F 7100-2. Once sufficient data is collected (*i.e.*, a minimum of five years’ worth), PHMSA can analyze the data to determine if new or modified regulatory requirements are necessary and, if so, to what degree. PHMSA’s justification for creating such extensive reporting requirements for non-regulated pipelines is that the data resulting from this reporting will help support an evaluation of the effectiveness of current regulations and the determination of new requirements. However, PHMSA does not address

²¹ <http://www.gao.gov/products/GAO-12-388>

whether imposing significant new reporting requirements is the most efficient and cost-effective way to accomplish these goals, nor whether this approach is consistent with its statutory authority.

GPA Midstream notes that PHMSA recently clarified its intent with respect to the applicability of the Part 191 reporting requirements to gathering line operators in a series of webinars conducted after the publication of the NPRM. PHMSA indicated that it intends to apply all of the Part 191 reporting requirements to operators of regulated gathering lines, *i.e.*, Type A, Area 1, Type A, Area 2, and Type B, but that it only intends to apply the annual and incident reporting requirements in Part 191 to operators of unregulated gathering lines, *i.e.*, those that do not meet the criteria to warrant regulation as Type A or Type B lines under the proposed rules. Of particular importance, PHMSA specifically acknowledged that it does not intend to apply the safety-related condition reporting requirements (including the MAOP exceedance provisions) to operators of unregulated gathering lines. GPA Midstream appreciates these clarifications and believes the information provided in the preceding paragraphs demonstrates why PHMSA should make additional changes to the proposed reporting requirements in the final rule.

GPA Midstream encourages PHMSA to undertake the modified data collection effort described above for future use in determining whether further oversight is warranted, and if so, to what degree.

GPA Midstream also wishes to reiterate its belief that the costs, both one-time and recurring, for annual reporting are dramatically underestimated.

B. New or Revised Definitions-- Part 192

In the Notice, PHMSA proposes to add 15 new definitions and revise two current definitions. GPA Midstream is providing comments on eight (8) of these proposals. For the remainder, we either support PHMSA's proposal or have no objections or suggested changes.

PHMSA is proposing to add a new definition for **Close Interval Survey** and revise the current definition of **Electrical Survey**. As proposed, the two appear to be almost duplicative. The proposed close interval survey is a fairly representative depiction of what is commonly understood in the industry when that term is used. The definitions of electrical survey, as it currently exists in the regulations and as PHMSA has proposed, are far more restrictive than as defined by the National Association of Corrosion Engineers (NACE) in NACE SP0169: Control of External Corrosion on Underground or Submerged Metallic Piping Systems. For example, Current Voltage Gradient (DCVG/ACVG), Pipeline Current Mapper (PCM/PCM-A-frame), and Guided Wave Ultrasonic (GWUT) all fall within this broader definition. When the Research and Special Programs Administration ("RSPA"), PHMSA's predecessor agency, first proposed the

current definition {68 FR 53895} multiple commenters argued that the proposed definition was too restrictive and limited the ability to select the most appropriate tool(s) to identify problems.

GPA Midstream recommends that PHMSA adopt the definition of “close interval survey” as proposed and adopt the definition of “electrical survey” as defined in NACE SP0169 instead of the definition it has proposed.

GPA Midstream is reasonably confident that PHMSA’s proposal to introduce a new definition for **Dry gas or dry natural gas** is intended only for use in identifying those circumstances when it is permissible to use the standard NACE SP0206–2006. However, in the past, gas quality has been used to determine the function of a particular pipeline; the transportation of “dry gas” has been viewed as transmission service rather than gathering, on the assumption that water is removed in the course of gathering and processing. However, this approach is not consistent with all natural gas production, the definitions in API Recommended Practice-80 (First Edition, April 2000) (RP-80), or the proposed new definition of gathering.

Therefore, GPA Midstream requests that PHMSA clearly state that the proposed definition is not for use in determining the transportation function of a particular pipeline. Other definitions, existing and proposed, serve that purpose.

PHMSA is proposing to eliminate the Incorporation by Reference (IBR) of the publication known as RP-80. GPA Midstream member companies, along with others, played key roles in the development of the document. GPA Midstream met with RSPA officials in 1999 and GPA Midstream welcomed their involvement during the development of RP-80. GPA Midstream recognizes the objections voiced by National Association of Pipeline Safety Representatives (“NAPSR”) and others to reference the document during the rulemaking initiative for gas gathering in 2003-2006 {Docket PHMSA-1998-4868}. PHMSA has described difficulties in applying and enforcing the variety of descriptors used in RP-80 to achieve consistent results. Instead of commenting on the proposed definitions as they appear alphabetically, GPA Midstream will address each of the definitions related to determination of gathering line classification as a group.

GPA Midstream notes the proposed definition of **Gas Processing Plant** uses at its basis the definition contained in Section 2.4.1 of RP-80. GPA Midstream supports this. GPA Midstream also recognizes recent events and confusion surrounding delineation of authority between PHMSA regulations and OSHA regulations and the extensive amount of work that has taken place to clarify those boundaries.

For that reason, GPA Midstream proposes PHMSA modify the definition by inserting the clause denoted by the underlined italics as follows:

Gas processing plant, as used to define Gathering line (Onshore), means a natural gas processing operation, other than production processing, operated for the purpose of

extracting entrained natural gas liquids and other associated non-entrained liquids from the gas stream and does not include a natural gas processing plant located on a transmission line, commonly referred to as a straddle plant. *A gas processing plant is not subject to this Part.*

PHMSA is proposing a new definition for **Gathering Line (onshore)**. The definition states, in part: ...transport it to the furthestmost point downstream of the endpoints described in paragraphs (1) through (4) of this definition:

- (1) The inlet of 1st gas processing plant, unless the operator submits a request for approval to the Associate Administrator of Pipeline Safety that demonstrates, using sound engineering principles, that gathering extends to a further downstream plant other than a plant located on a transmission line and the Associate Administrator of Pipeline Safety approves such request;...**
- (4) The point where separate production fields are commingled, provided the distance between the interconnection of the fields does not exceed 50 miles, unless the Associate Administrator of Pipeline Safety finds a longer separation distance is justified in a particular case (see § 190.9).**

GPA Midstream seeks clarification concerning the process which must be used to gain approval or seek a determination. Typically, PHMSA references §190.9, Petition for Finding or Approval. But requests submitted under §190.9 are directed to the Administrator, not the Associate Administrator. Thus, GPA Midstream requests PHMSA clearly cite to the authority under which any request is to be submitted, or revise the references to be consistent with the procedures in Part 190. Any required notice should reference applicable state agencies in the case of intrastate facilities.

Further, in paragraph (5) of the Gathering Line definition, PHMSA proposes that gathering may continue beyond the four identified endpoints under certain circumstances. GPA Midstream believes this to be PHMSA's attempt to correct what are alleged to be editorial errors in linking RP-80 definitions to the limitations on the endpoints of gathering described in §§192.8(a)(2),(3), and (4), as discussed in two interpretation letters issued to CDX Gas and the Kansas Corporation Commission.²² GPA Midstream believes the proposed limitation of one mile is too restrictive. GPA Midstream believes a maximum extension of ten miles strikes a more appropriate balance between the need to accommodate differences in pipeline systems and the need to establish a more definite endpoint, while limiting the unintended consequences of

²² **Interpretation #09-0002** July 14, 2009; **Interpretation #09-0008** (Jul. 30, 2009). PHMSA acknowledged that operators could use the incidental gathering designation in the March 2006 final rule, at 71 Fed. Reg. at 13,292. While expressing a desire to revisit that issue in a subsequent rulemaking proceeding, PHMSA also confirmed that the incidental gathering line designation could be used in the letters of interpretation issued to CDX Gas and the Kansas Corporation Commission in July 2009.

forcing a reclassification of miles of what are currently defined as gathering pipelines. Consideration of neighbors and surrounding land use are key factors when locating and siting large scale facilities, such as compressors and processing plants, resulting in distances longer than one mile. PHMSA must be cognizant of the fact that any extension of an existing pipeline past the endpoint of gathering, as proposed, will be classified as transmission resulting in significantly increased costs and compliance burdens for operators of such lines, and PHMSA must assess such costs in the RIA. As discussed later in our comments, PHMSA has not taken this impact into consideration in § 192.619.

Second, PHMSA is proposing to recognize the extension of gathering beyond those “furthestmost” facilities as long as certain conditions exist. The proposed text, in part, is as follows:

...

Gathering may continue beyond the above endpoints to the point gas is delivered into another pipeline, provided ~~that it only does the following:~~

(i) ...;

(A)...

GPA Midstream questions the need to include the language that is stricken, italicized, and underlined above. This is inconsistent with past PHMSA regulatory structure and adds no clarifying value. Placement of the colon after the term “provided” would be consistent with the structure in the remainder of the document.

One of the proposed criteria for defining when a gathering line may continue beyond the furthestmost facility is the determination that the line does not cross a “highway” or “active railroad”. Both terms, highway and active railroad, have existed within Part 192 since its inception, but have only been defined through the use of interpretation letters²³. However, elsewhere within this proposal, PHMSA is proposing to introduce a new term, Moderate Consequence Area, for which PHMSA incorporates terms used in the Federal Highway Administration’s²⁴ (“FHWA”) classification of highways in order to clearly identify which roadways are covered. GPA Midstream comments further on this proposed new definition below, but recommends that PHMSA use the same FHWA definitions in the definition of Gathering Line to ensure consistency throughout the regulation. GPA Midstream is also concerned about the use of this criterion in determining the endpoint of gathering, because it is not related to the use of the pipeline but rather to the proximate surface uses, unlike the other criteria in this definition.

²³ Daniel Meyers Interpretation 192.11 29, June 7, 1978, Olin Greene Interpretation 192.11 15 December 6, 1974

²⁴ Highway Functional Classification: Concepts, Criteria and Procedures, 2013 Edition

GPA Midstream urges PHMSA to use consistent definitions to refer to roadways, and to eliminate the reference to roads and railroads as a criterion in determining the endpoint of gathering.

The following revised definition of endpoint is recommended:

- (5) Gathering line may continue...provided: ~~that it does the following:~~**
- (i) It delivers gas into another gathering line;**
 - (A) It does not leave the operator's facility surface property (owned or leased, not necessarily the fence line);**
 - (B) It does not leave an adjacent property owned or leased by another pipeline operator's property—where custody transfer takes place; or**
 - (C) It does not exceed a length of ten miles, and it does not cross ~~a state or federal highway or a right-of-way for a designated interstate, freeway, expressway, and other principal 4-lane arterial roadway as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures~~ or an active railroad; or ...**

In the last part of the definition of a gathering line, paragraph (6), PHMSA expressly excludes service lines that are commonly referred to as farm taps from the definition of gathering line. The NPRM states that these service lines originate from gathering lines, but PHMSA has previously described these service lines as originating from production, gathering or transmission pipelines, such as in the July 10, 2015 NPRM. In order to ensure consistency and eliminate confusion, GPA Midstream proposes that the last sentence read:

Pipelines that serve residential, commercial, or industrial customers that originate at a tap on production, gathering, or transmission lines; they are service lines and are commonly referred to as farm taps.

PHMSA has proposed a new definition for **Onshore production facility or onshore production operation**. Unlike the approach taken with the proposed new definition for **Gathering line (Onshore)**, PHMSA's proposal differs significantly from the definition contained in RP-80. API members, some of which are also GPA Midstream members, engage in the production of gas as their primary business. These members are more capable of articulating the problems with the definition PHMSA has proposed.

GPA Midstream supports the positions put forth in the comments filed by the API on this topic.

PHMSA is proposing to introduce two new terms for use in identifying pipelines which may be subject to new testing and verification processes. These are **Legacy construction techniques** and **Legacy pipe**. GPA Midstream seeks clarification with regards to one of these terms.

Within the proposed definition of **Legacy construction**, PHMSA has used the term "now abandoned," which GPA Midstream understands to mean the described construction practices are no longer used. However, the term abandoned is used elsewhere to designate pipelines that

have been permanently taken out of service. Although this is a remote prospect, GPA Midstream recommends that PHMSA use a different term to communicate its meaning, so that there is no implication that pipelines that have been taken out of service may somehow be subject to the proposed testing and verification in §192.624(c). Also, although this term is used only for determining which lines are subject to the testing and verification called out in §192.624, which is titled in part “Onshore Steel Transmission...”, GPA Midstream is concerned that if the term is used more broadly in the future, it will come to encompass practices that are perfectly acceptable when used in applications such as distribution and lower pressure, smaller diameter gathering lines.

GPA Midstream suggests PHMSA modify the definition as follows;

Legacy construction techniques mean usage of any historic, ~~now-abandoned~~ *no longer permitted*, construction practice to construct or repair pipe segments of steel transmission lines, including any of the following techniques; ...

PHMSA has proposed the inclusion of a new definition for **Moderate Consequence Area (MCA)** for use in determining which areas, outside of HCAs, will be subject to the proposed regularly scheduled assessments as proposed in the new §192.710. One of the criteria which will be used to determine if an area is considered a MCA is the term “**Occupied Site,**” which, too, is a new definition.

Paragraph 1 of the proposed **Occupied Site** definition describes outdoor areas used for occasional but recurring activities, such as campgrounds, theaters, beaches, and recreational facilities. In providing such examples, PHMSA has not clearly indicated whether the definition includes other outdoor locations which are used in transient but more commercial activities, such as parking lots. PHMSA should clearly include or exclude parking lots, golf courses, and similar commercial use locations where people congregate on an otherwise-similar basis.

Paragraph 2 of the proposed **Occupied Site** definition describes a building which is occupied by five (5) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. GPA Midstream has several concerns with this portion of the proposed definition. The proposed occupancy rate is 25% of that for HCAs as defined in §192.905(b), and essentially dilutes the greater focus on HCAs intended by the Integrity Management Program regulations. Moreover, although the examples PHMSA has provided are “quasi commercial” or commercial in nature, the definition is not expressly limited to commercial buildings. As written, any residence housing a family of five would be included, although the feasibility of determining such residential occupancy is not addressed. Current class location studies and public awareness programs do not include information about number of persons residing in any structure intended for human occupancy, nor is reliable data on occupancy available to pipeline operators. Even if operators could obtain or develop such

information, PHMSA has not included the costs of such information gathering and management in its RIA.

Even if PHMSA limits this definition (as GPA Midstream believes was the intent) to commercial and quasi commercial establishments, PHMSA has still not provided further direction as to how the duration of the occupancy should be determined. For example, would the presence of five persons for 10 minutes a day in a general store constitute an **Occupied Site**? If this criterion remains in the final rule, GPA Midstream believes PHMSA should define the minimum hours of occupancy for the days occupied at not less than four hours.

Finally, within the proposed definition of MCA, which includes an area within a potential impact circle containing a major roadway or highway, PHMSA has incorporated a reference to a FHWA standard classifying such highways. GPA Midstream has reviewed the document and determined that the FHWA classification includes many more categories of roadway than the terms used in the proposed definition, raising the question of whether PHMSA intended to cover every type of roadway included in the FHWA document. As proposed, therefore, the definition may not be as clear or easy to apply as PHMSA envisions. PHMSA could simplify and clarify the definition by limiting the criterion to only interstate highways, for example, and including the specific FHWA definition in this regulation. If, after consideration of all comments submitted on this topic, PHMSA desires to reference the FHWA document, it should clearly state that the definition is restricted to those arteries PHMSA used in describing the proposed assessment requirements, "...interstates, freeways, expressways, and other principal four-lane arterial roadways," and no others.

PHMSA states in the RIA²⁵ that it has evaluated pipelines that may "...overlap with interstates, freeways, expressways, and other principal four-lane arterial roadways," implying that these are the only roadways which fall into the definition of MCA and pipelines subject to the required assessments. However, from the referenced FWHA document,²⁶ the document describes roads which contain very few access points. GPA Midstream urges PHMSA clearly define in final rule language these are the only roadways included, if roads are to be included at all. As proposed and depicted in the Table below from the FWHA document, the definition may not be as clear as PHMSA envisions.

²⁵ Id: 52

²⁶ Highway Functional Classification: Concepts, Criteria and Procedures, 2013 Edition

Table 2-1: Relationship between Functional Classification and Travel Characteristics

Functional Classification	Distance Served (and Length of Route)	Access Points	Speed Limit	Distance between Routes	Usage (AADT and DVMT)	Significance	Number of Travel Lanes
Arterial	Longest	Few	Highest	Longest	Highest	Statewide	More
Collector	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Local	Shortest	Many	Lowest	Shortest	Lowest	Local	Fewer

All of the terms used; longest, few, highest and more are inconclusive for use in implementing such a costly regulatory requirement.

The estimated cost for performing the investigations necessary to make the determinations was not included in the RIA, (Page 33²⁷). There is a dramatic difference in the effort necessary to search for areas potentially containing twenty or more persons compared to structures occupied by five persons. Even when aided by the use of aerial photography, on the ground follow-up will be required for each structure in question even if PHMSA ultimately limits it to “commercial” structures. One GPA Midstream member has conducted a cursory evaluation of the estimated cost to perform evaluations to identify **Occupied Sites** and has concluded that this task will require approximately 10,000 personnel hours per year. At PHMSA’s cost for a field technician, this equates to \$550,000 per year, or \$8.25MM over the 15-year period, for one operator. If only one-third of the GPA Midstream membership experiences similar expenditures, the cost for this portion of the proposal will be approximately \$22MM per year. Lastly, PHMSA has not defined a timeline for initial identification of these new MCA’s. It has not communicated expectations for ongoing evaluations or treatment of newly-identified locations.

GPA Midstream recommends that the criterion used in the MCA definition be limited to interstate highways.

*GPA Midstream urges PHMSA to eliminate the definition of **Occupied Site** and remove this criterion from the proposed definition of **MCA**. Doing so would more clearly distinguish between MCAs and HCAs and provide greater clarity to identifying and managing MCAs.*

*If PHMSA does not eliminate **Occupied Site** from the final rule, then PHMSA should define it as follows;*

²⁷ Because operators must have already performed analysis in order to have identified HCAs, or verify that they have no HCAs, PHMSA assumed that the cost of identifying MCAs is negligible compared to the cost of assessments and did not quantify the cost to identify MCAs.

Occupied site means each of the following areas:

(1) ,,,; or

(2) A **non-residential** building that is occupied by five (5) or more persons on at least five (5) days a week **for at least four hours per day** for **any** ten (10) weeks in any twelve (12) month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks.

PHMSA should clearly communicate expectations regarding timelines for identifying MCAs and for periodic updates.

The recurring costs for the identification of MCA's and Occupied Sites MUST be clearly identified in the RIA.

C. Subpart A – General

§192.5 Class Location

GPA Midstream does not dispute PHMSA's assertion that accurate records related to class location are a necessary component in assuring the MAOP is commensurate with the current class location and for establishing inspection intervals for activities, such as patrols. GPA Midstream does not see any value in keeping the records of every study conducted, if no changes are noted, for the life of the pipeline. The data used for initial determination of the MAOP is relevant. The same is true for surveys which indicate the class location has changed. When a change is noted, the new survey takes precedence and other documentation for compliance with §192.611 will be in place as applicable. Any surveys conducted which indicate no change serve no purpose beyond a check mark on an inspection form.

GPA Midstream requests PHMSA change the proposed requirement to read as follows:

(d) After {insert effective date}, records for transmission pipelines documenting class locations and demonstrating how an operator determined class locations used for initial determination of the MAOP and any subsequent surveys which indicate a change in class location in accordance with this section must be retained ~~for the life of the pipeline.~~

§192.7 Incorporation by Reference

PHMSA has proposed to incorporate by reference several new industry consensus standards and GPA Midstream's focus here is on the three related to the conduct of inline inspections. PHMSA is proposing to reference API 1163 (2005), NACE SP0102 (2010), and ASNT PQ 2005. In the ANPRM, question C.7 asked if PHMSA should adopt standards associated with conducting inline inspections. The vast majority of the responders that directly

addressed the question posed did not object to the use of the standards but did oppose PHMSA's adoption of them merely because of the slow process of updating to more current editions. Historically, standards tend to keep pace with advances in technological change resulting in documents which better reflect the available accuracies and practices, in this case. PHMSA's proposal reinforces this argument. PHMSA is proposing to reference the 1st Edition API 1163 and ASNT PQ 2005, when both have been updated already, and not necessarily recently, to the 2nd Edition 2013 and 2010 respectively.

GPA Midstream stands with its original comments filed in 2012 that PHMSA should not reference the documents, but make reference to them as guidance documents. If PHMSA does not heed that suggestion, then GPS urges PHMSA to reference to the most recent Edition of the standards.

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

PHMSA has proposed to extend its oversight of onshore gas gathering lines into Class 1 locations through the creation of a "Type A, Area 2" grouping which would include all lines eight inches (8") in diameter and greater and which have an MAOP that is equal to or greater than 20% SMYS for metallic lines, or which have an MAOP greater than 125 psig for non-metallic lines.

PHMSA's reasoning for the proposed regulatory expansion is based on three pretexts: first, the purported extrapolation of incident data from regulated gathering to the unregulated mileage; second, a General Accountability Office ("GAO")²⁸ report; and lastly, current public opinion. When discussing the potential expansion of gathering with PHMSA's Technical Pipeline Safety Standards Committee (TPSSC, now known as GPAC) on March 24, 2013, PHMSA stated that it thought it appropriate to extend oversight to the "larger-diameter, higher pressure" rural gathering. The GAO report cited by PHMSA included in the discussion of its findings "that some newly built gathering pipelines have larger diameters and higher operating pressures that more closely resemble transmission pipelines than traditional gathering pipelines. For example, while gathering pipelines have traditionally been 2 to 12 inches in diameter ...". PHMSA, in the RIA²⁹, states "Gathering lines are being constructed as large as 36 inches in diameter with maximum operating pressures up to 1480 psig. These characteristics far exceed past design and operating parameters of typical gathering lines." In all documents, testimony, and discussions between the agency and various non-industry interest groups, sentiment has been consistent that the "larger-diameter, higher pressure, higher risk" gathering should be regulated. While GPA Midstream is opposed to expanding the regulation of gathering pipelines, GPA Midstream believes that if it is to occur, such regulation should be consistent with the rationale that has been promoted in PHMSA's previous statements and writings: larger-diameter, higher-pressure pipelines.

²⁸ GAO Report 14-667

²⁹ Id 101

However, PHMSA's proposal departs from its earlier statements, by seeking to regulate an arbitrarily larger population of gathering pipelines, both directly and, as discussed earlier, indirectly through new reporting requirements for non-regulated gathering lines. PHMSA has proposed to include much smaller diameter pipelines than previously discussed in its new Type A, Area 2 category of metallic gathering pipelines of 8 inches or greater in diameter, and operated at 20% or more of SMYS, and non-metallic gathering lines operated at more than 125 psig. PHMSA's proposal to use the 8-inch diameter, rather than the larger diameters typical of the "new" shale plays identified as an illustration of the need to change the regulatory approach to gathering lines, is not supported by the safety incidents it cites in the Notice. PHMSA briefly describes incidents on three non-regulated gathering lines, saying that these incidents show that non-regulated gathering lines are subject to the same kinds of failures as regulated pipelines. However, two of the three incidents involve excavation damage, which is already addressed through damage prevention programs and not through the proposed rules. Of those two incidents, one was caused by an excavator who did not make the required one-call notifications and ignored both markers and previous knowledge of the pipeline's location. Notably, none of these three incidents involved a pipeline with a diameter of 8 inches. If anything, these incidents illustrate the unfortunate principle that it is not possible to eliminate the role of human action or inaction in accidents, pipeline or otherwise.

PHMSA states in Section 6.2 of the RIA that it has no incident data on the unregulated gathering, so it used data on comparable regulated transmission lines. In the attempt to characterize the perceived risk, PHMSA used gas transmission incident data from Class 1 and 2 locations, and assumed that non-regulated gathering would have a higher rate of incidents. There are two inherent flaws in this analysis. First, it stands to reason that the consequence costs are higher for pipelines in Class 2 locations, because these locations have higher population densities, resulting in more evacuations, business interruptions and potentially more property damage. These data cannot represent gathering pipelines in Class 1 locations. Second, there is no data supporting the proposition that unregulated gathering performs more poorly on measures of safety than transmission as claimed. API / GPA Midstream data submitted by Emmert in 2012 provided PHMSA with actual numbers of fatalities and injuries for 2007 to 2011 on Class 1 gathering not regulated by PHMSA, so GPA Midstream has used these years to compare with PHMSA's RIA assumptions. In the 2007 to 2011 timeframe, there were 6 fatalities and 16 injuries on the 236,548 miles of non-regulated gathering reported by the participating companies. This is a rate of 1:10752 miles of pipeline. PHMSA reports show 12 fatalities and 85 injuries or 1:3111 miles for the same time period on transmission (RIA Table E-1). Clearly, there is a significant difference between the safety metrics associated with Class 1 and 2 transmission pipelines and those corresponding to nonregulated gathering during the same time period, but that difference does not support PHMSA's creative, if not incorrect, assumptions. GPA Midstream also questions PHMSA's claim of reduction in methane releases. PHMSA shows the estimated number of releases averted as escalating over the fifteen year period of the RIA, when the actual number of incidents had shown a decline, with none occurring in years 2013 and 2014.

If the expected releases averted is questionable, then so are the expected benefits identified in Tables 6-10 and 6-11.

The transmission incidents PHMSA cites highlight the disparity between the evidence PHMSA points to and the parameters it proposes in the NPRM, as well as the actual relationship between diameter and MAOP as a percentage of SMYS. Of those incidents, the Sissonville, West Virginia incident involves the smallest diameter pipeline, at twenty inches (20”), and was operating at 921 psig. The public records do not indicate the MAOP of this line, but a calculated potential impact radius (“PIR”) for the Sissonville pipeline at its operating pressure would have been 420 feet. In contrast, an eight inch (8”) pipeline at a MAOP of 720 psig would have a PIR of 149 feet; the same 8” pipeline operating at 200 psig would have a PIR of only 79 feet. In order to arrive at a PIR that is similar to that of the Sissonville line requires a sixteen inch (16”) line with a MAOP of 1480 psig, resulting in a 425’ PIR. A 16” line operating at 300 psig would produce a PIR of less than half that figure, or 192 feet. If PHMSA is concerned about the potential impact of a failure on the surrounding area, PHMSA must take into account the physical relationship between pipeline diameter and its MAOP. Smaller diameter pipelines, such as an 8-inch line, must be operated at a pressure much higher than 20% of SMYS in order to have the same PIR as a larger diameter pipeline. Furthermore, for a steel pipeline of standard specifications, a MAOP equal to 20% of SMYS represents a much lower pressure for a pipeline with a 30-inch diameter than for a pipeline with an 8-inch diameter. In fact, for a standard 20-inch diameter pipeline, an operating pressure equal to 20% of SMYS would be less than 300 psig, suggesting that the Sissonville pipeline was operating considerably above 20% of SMYS, whatever its MAOP may have been.

Gathering pipelines are rarely operated at pressures close to their MAOP. This is one major reason the risk from gathering lines is far lower than transmission. When a new “play”, such as Barnett or Marcellus, is first explored, very little infrastructure is in place to transport the production to processing and then to market. The initial gathering lines flow at higher pressures because capacity is limited and because it is needed in order to facilitate delivery into the gas transmission lines at sales locations. The main reason diameters are large in these new fields is to accommodate volume. As development progresses and gathering compression is added in the field, pressures are lowered significantly for gathering lines, because they are located on the suction side of the compressors by design. Keeping the pressure as low as possible on a gathering line allows more gas to flow from the connected wells. Thus, although a gathering line has an MAOP of 1440 psig, it may never operate above 150 to 200 psig. GPA Midstream believes the risk should be evaluated against this, instead of a MAOP that is designed, tested, and established at a much higher level primarily to keep everything uniform. This is particularly true in the newer shale play build outs.

As proposed, PHMSA will allow six months to evaluate an estimated 344,000 miles of gathering pipe to determine the beginning and endpoints, identify all pipe of a diameter 8” and greater, determine whether the identified pipe meets the criteria for classifying it as Type A, and

then have all prescribed programs implemented within another 18 months. This is an unrealistic expectation. Unlike cross country transmission that is typically diameter consistent from beginning to end, gathering systems are built in segments to facilitate new production as it is brought online. Each gathering line segment is sized to accommodate the anticipated production amount expected from a well times the number of wells expected to be connected eventually. The larger trunk lines are built with a vision of the overall development of a region within the play and may be telescoping in nature, growing larger as it nears final compression or processing. For this reason, identification of larger line sizes can be achieved more quickly. However, while the identification of the larger lines may be achievable more quickly, determining whether or not the MAOP is greater than or equal to 20% SMYS may be difficult and lengthy process, particularly if PHMSA intends to require reliable, traceable, verifiable, and complete (“RTVC”) material documentation records for line pipe, valves, flanges, and components for gathering lines. That topic is discussed in greater detail below. Even if PHMSA does not impose this standard, operators may not have the records needed to establish either MAOP or SMYS for pipelines that are newly regulated. PHMSA does not address this possibility, nor does PHMSA include the costs of determining such parameters where records are limited or missing in the RIA. Finally, by using such parameters to determine whether a Class 1 gathering line is regulated, PHMSA is in effect imposing retroactive requirements on these pipelines, which is expressly prohibited in 49 USC 60104. Operators may have sufficient operating history records to determine MAOP for such lines, pursuant to 192.619(c), but determination of SMYS requires various design criteria, such as wall thickness, outside diameter, and yield strength, that are not available and were not previously required for Class 1 gathering pipelines.

In addition to the retroactivity prohibition, GPA Midstream believes that a blanket six-month implementation timeline fails to recognize the overall complexity of what is being proposed in this Notice. As such, GPA Midstream offers the following example of a mileage and diameter-based guide for the implementation of any final rule.

Diameter Basis	500 total system miles of pipe	On-shore Regulated Gas Gathering Only						Transmission MOC
		Identify (ID) affected pipeline	ER Plans following ID	Pub. Awareness following ID	Corr. Control following ID	Ann. Leak Survey following ID	MAOP verification following ID	
Greater than 12"	Op'd. miles over	48 mos.	24 mos.	24 mos.	48 mos.	30 mos.	84 mos.	48 mos.
	Op'd. miles under	40 mos.	24 mos.	24 mos.	40 mos.	24 mos.	80 mos.	48 mos.
Greater than 16"	Op'd. miles over	36 mos.	20 mos.	24 mos.	36 mos.	24 mos.	72 mos.	48 mos.
	Op'd. miles under	30 mos.	20 mos.	24 mos.	30 mos.	20 mos.	60 mos.	48 mos.
20" and Greater	Op'd. miles over	18 mos.	12 mos.	24 mos.	24 mos.	18 mos.	48 mos.	48 mos.
	Op'd. miles under	18 mos.	12 mos.	24 mos.	20 mos.	12 mos.	36 mos.	48 mos.
Implementation timelines for these activities begin AFTER the Identification (ID) phase								

The cost to benefit ratio, even using PHMSA’s numbers, are negative on the benefit side. Throughout these comments, GPA Midstream has provided costs that reflect current information from our members, and these indicate that the actual costs of the proposed regulation will be much higher than PHMSA has estimated. PHMSA has used costs provided by IPAA back in 2005, which were used to support the 2006 rulemaking. GPA Midstream does not dispute the validity of the numbers as used then. However, PHMSA has simply applied a rate of inflation to

project costs anticipated for compliance for this proposal. While this may be a valid method in some instances, it does not accurately reflect costs when program requirements have changed over time. For example, when those IPAA figures were submitted, PHMSA had just implemented enhanced requirements for Public Awareness programs, and therefore the costs associated with the requirement to evaluate effectiveness were not factored in. The same is true of emergency response plan development and implementation including the expectations related to interactions with the emergency responder community. Class 1 locations tend to be covered by volunteer fire departments which present more challenges to reach and conduct the required liaison, often at night, resulting in overtime pay. Section 3.8.2.3 of the RIA states that “[f]or this analysis, PHMSA assumed that many operators already substantially comply with some portions of the proposed rule.” GPA Midstream does not dispute that our member companies may conduct many of these activities, but training and implementation costs for a larger scope of work will create administrative costs which have not been considered in the PHMSA analysis.

GPA Midstream has examined realistic updated numbers based on what member companies have recently spent on regulated gathering and transmission mileage. Several member companies have provided actual costs related to the impacts of the proposed requirements for Type A, Area 2 compliance activities which demonstrate both the gross underestimation in the numbers for cost used by PHMSA in the RIA, and how PHMSA could more closely align the costs to the perceived benefits by adjusting the pipeline diameters in its criteria.

- Operator “A” indicates it will cost approximately \$187 per mile for recurring costs to cathodically protected pipe to implement the proposed eight compliance activities. This is \$20 per mile more than PHMSA estimates in Table 3-92 for Operator Group 2, adding \$1.4MM to the recurring costs.
- Operator “B”’s costs are \$280 per mile based on what it currently spends per mile on the specified programs for its regulated assets.
- Operator “C” has indicated it will incur costs of \$1000 per mile to obtain PHMSA compliant cathodic protection levels and it will cost \$150 per mile in recurring cathodic protection costs alone. This brings the total recurring costs, without factoring in the elevated costs for pipe that is not cathodically protected, to \$19,249,720, not the \$13,791,875 PHMSA estimated. This \$1.4MM to \$5,457,845 per year difference will add between \$21MM and \$81MM without adjusting for inflation to the total 15 year cost just for the Type A, Area 2, without giving any consideration to the impact of complying with the MAOP records verification component, if PHMSA intended it to apply to gathering.

- Operator “D” comes in with \$713 per mile on its currently regulated mileage, which is a large amount of mileage and is spread over several states. At this rate, including pipelines of 8” and greater in Class 1 is projected to add over \$10MM per year to their regulatory program costs.
- Operator “E” will have recurring costs of \$173 per mile for corrosion control activities only, bringing their cost per mile for seven of the eight activities to \$575 per mile per year. The costs shown for Operator “E” do not include establishing the MAOP on the potentially affected mileage.

It is apparent to GPA Midstream that PHMSA did not consider pipelines constructed using materials that are not yet authorized under Part 192, such as composites and polyethylene manufactured to standards other than ASTM D2513, although such pipelines may be safely operated at higher pressures than standard “plastic” pipelines, and will therefore be considered Type A. Operators commonly use these technologies where they can to eliminate threats such as internal corrosion and to minimize environmental impact during construction since they do not require as much right-of-way. In the 2012 data submitted to the docket, members reported over 11,400 miles of Type A, Class 1 pipe classified as “Other”. Since plastic was reported separately, it is a relatively safe assumption these lines are composites. There were over 7100 miles of Type A, Class 1 reported as plastic. What cannot be determined from this data set is how much is ASTM D2513 and how much is ASTM F2619 or API 15LE polyethylene for oil and gas gathering. And because the decline in commodity prices did not halt new gathering construction until well into 2014, it is probably safe to assume that mileage increased another 10% in 2013 to 2014 bringing the total to approximately 20,000 miles combined. It is plausible that the vast majority of this 20,000 miles will be impacted since composites may be produced in diameters of eight or possibly ten inch with pressure ratings up to 3,000 psig, and ASTM F2619 poly can be produced in diameters as large as sixty five inch, but use of sixteen to twenty inch is not uncommon in gathering applications at pressures up to three hundred (300) psig. This places both of these material types into the Type A category as defined in §192.8. If adopted as PHMSA has proposed in the NPRM, the result will be an indirect prohibition of non-metallic gathering lines through pressure limits and other requirements. Additionally, PHMSA has not taken any steps to adopt by reference the most recent performance standards relating to non-metallic pipelines and composite materials. Non-metallic lines are currently in use in the industry and offer safer, more corrosion resistant service than steel lines for many applications. Currently, these composite lines are safely operated in many areas carrying linear and aromatic hydrocarbons, hydrogen sulfide (H₂S) and carbon dioxide (CO₂) gasses, and low pH highly saline brines. We feel these unnecessary limits will not encourage advancements for improving safety in gathering lines. PHMSA has not provided any discussion of how these materials will be accommodated with respect to the standards they were manufactured or expectations for establishing MAOP. Nowhere in the RIA have costs associated with requiring replacement of

any pipe been included, and certainly not 20,000 miles of Class 1 gathering pipe. PHMSA could alleviate this problem by limiting the scope of any expansion to include steel lines only.

GPA Midstream does understand PHMSA's need to respond to the concerns raised by public representatives and the findings put forth by the GAO, but balance must be achieved by focusing on larger diameter, higher pressure pipelines. GPA Midstream is confident that PHMSA understands that simply because it does not regulate these lines does not mean they are not regulated. The report³⁰ required by Section 21 of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which PHMSA transmitted to congress May 8, 2015, clearly indicates that gathering lines are not without regulatory oversight in most locations. As shown in the data submitted in 2012 to the docket, a substantial savings on the costs of the proposed regulations could be achieved by establishing a higher diameter threshold for determining regulated gathering, which would also be consistent with the larger-diameter, higher-pressure, "riskier" pipelines that PHMSA seeks to regulate.

GPA Midstream believes PHMSA should defer extending oversight until sufficient data is collected to permit a data driven, risk-based analysis.

If PHMSA insists on continuing with this portion of the rulemaking, GPA Midstream urges PHMSA to modify the criteria applicable to steel gathering pipelines in the final rule to a diameter of greater than 16 inches, and an MAOP greater than 20% of SMYS. PHMSA should also clarify the standards for determining MAOP applicable to gathering lines, both for purposes of definition and for purposes of compliance.

Given the use of newer composite materials in pipeline fabrication, GPA Midstream urges PHMSA to evaluate whether the same MAOP standard should apply to different types of non-metallic and composite lines, and to consider addressing these differences in a subsequent rulemaking.

§192.9 What requirements apply to gathering lines?

The proposed modifications to §192.9(c) includes exceptions for gathering lines that are Type A, Area 1. The proposal states that §192.13 is not applicable to Type A, Area 1 gathering lines, but §192.13(a) and (b) provides for the applicability of design, installation, construction, initial inspection, initial testing requirements to pipelines based on in-service dates, or dates of replacement, relocation or change of those pipelines. GPA Midstream believes this may be a drafting error. GPA Midstream thinks that §192.13(a) and applicable portions of § 192.13(b) are necessary to establish starting points properly apply the regulations.

Other proposed exceptions for Type A, Area 1 include §§192.150, 192.319, 192.461(f), 192.465(f), 192.473(c), 192.478, 192.710, 192.713. As with the proposed blanket exception for §192.13 above, GPA Midstream is confident PHMSA did not intend to exclude Type A, Area 1

³⁰ Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Gathering Lines

from all of the requirements currently stipulated in §192.319, but intended to exclude only the proposed §192.319(d). In addition, none of these same exceptions were provided for the Type A, Area 2 or Type B lines. GPA Midstream believes that §192.9(d)(1) should be revised to exclude §§192.150, 192.319(d), 192.710, and 192.713 from the requirements applicable to Type A, Area 2, and Type B lines. The same changes are warranted §192.9(d)(2) as it relates to the proposed §§ 192.461(f), 192.465(f), 192.473(c), and 192.478.

In proposing that the newly-defined Type A, Area 2 gathering follow the requirements previously established for Type B gathering, GPA Midstream believes PHMSA failed to recognize the relative utility of one of the risk control activities required for such Type B lines. In a recent rulemaking,³¹ PHMSA added a requirement for leakage surveys to be conducted on Type B gathering lines. The requirement to use leak detection equipment was predicated on the propensity for these lines to leak in a similar fashion as gas distribution lines. Leaks which occur on “larger-diameter, higher-pressure” gathering will be detectable without the use of leak detection equipment.

GPA Midstream urges PHMSA to modify the language in §192.9 to accurately reflect its intended application of Part 192 to newly regulated Type A and Type B gathering lines. If the published proposed rule does reflect PHMSA’s intention, then GPA Midstream objects to the regulation because the RIA does not reflect the costs of the limited exceptions.

GPA Midstream urges PHMSA to modify the language in §192.9(d)(7) to not require the use of leak detection equipment for Type A, Area 2 gathering lines when conducting leak surveys. Leak detection equipment is not required by §192.706 to perform leakage surveys for transmission lines or currently regulated Type A, Area 1 gathering lines. It does not make sense to require leak detection equipment on a Type A, Area 2 gathering line.

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

PHMSA is proposing several changes to §192.13, including Management of Change (“MOC”) requirements and recordkeeping requirements. The changes related to effective dates as they apply to gathering are discussed in the previous section of GPA Midstream’s comments, and will not be restated here. PHMSA is proposing to add an MOC requirement for transmission pipelines. In the Notice, PHMSA states “In addition, PHMSA also proposes to add a new subsection §192.13(d) that would apply to onshore gas transmission pipelines.” PHMSA has not included the necessary exceptions in §192.9 to make it clear the requirement is not applicable to gathering lines. Under PHMSA’s proposal, MOC procedures would be significantly expanded and extended beyond Subpart O’s pipeline Integrity Management (“IM”) provisions. PHMSA has not demonstrated a need to extend MOC requirements beyond those required for IM programs. Compliance with documentation requirements for every routine design change,

³¹ Miscellaneous Changes to Pipeline Safety Regulations: [Docket No. PHMSA-2010-0026; Amdt. Nos. 191-23; 192-120; 195-100] RIN 2137-AE59

change in maintenance procedures, or operational change would be both unnecessary and extremely burdensome. GPA Midstream concurs with the TPA assertion that this proposal is unwarranted and unduly burdensome. If PHMSA leaves this requirement in the final rule, GPA Midstream recommends that PHMSA insert “after effective date” language to ensure the requirement applies only to activities undertaken after the effective date of the final rule.

The insertion of the new paragraph (e) §192.13 appears nowhere in the preamble discussion, no reasons are provided to support the introduction of these requirements, no costs are detailed in the RIA, and as proposed, these requirements become applicable to every type of pipeline operator, except where noted in subparagraph (e)(1). Throughout the ANPRM and the NPRM, the acceptability standard for records has pointed to the terms PHMSA used in Advisory Bulletins: ADB 11-01 and ADB 2012-06. ADB 2012-06 used the terms Verifiable, Traceable, and Complete to describe which records might be used and how differing records might complement each other to substantiate the MAOP. PHMSA has not only inserted these three terms into the proposed §192.13(e) without explanation, it has done so without also providing a definition or reference to the existing standards to help explain how these standards should be applied. Although there is some precedent, as noted above, for the phrase “verifiable, traceable and complete,” PHMSA has also introduced a new term, “Reliable,” without explanation or definition, leaving the meaning of this term uncertain and its application highly subjective.

The proposed §192.13(e)(2) and (3) appear to be a dramatic and unwarranted expansion of the provisions in Section 23 of the 2011 Act regarding verification of MAOP for transmission lines in Class 3 and 4 locations, or HCAs in Class 1 and 2 locations. The Act did not include gathering lines within this mandate, nor did the Act incorporate the “verifiable, traceable, reliable and complete” standard for records that PHMSA has proposed here or elsewhere in the Notice. As written, the proposed regulatory provisions do not apply to Type A, Area 1 gathering, but will be applicable to all segments of Type A, Area 2 and Type B gathering and transmission lines which are new, relocated, replaced, or otherwise changed per §192.9(d)(1). PHMSA has provided no cost estimates in the RIA for generating and maintaining records for pipelines which may be impacted by this requirement. If PHMSA intended to exclude gathering lines, whether Type A, Area 1 or Type A, Area 2 and Type B from the requirements of §192.13(e), PHMSA must clarify in the final Rule to eliminate this uncertainty. If PHMSA did intend to apply these requirements to all gathering and transmission lines, PHMSA has not met its obligations to provide adequate review and comment, and did not adequately assess the costs and benefits of this proposal. PHMSA should also clarify that §192.13(e) does not apply to compliance records corresponding to pipeline operations prior to the effective date of the final rule.

GPA Midstream urges PHMSA to remove §§192.13(e)(2) and (3), or if it is still believed they are necessary, GPA Midstream recommends that PHMSA initiate a new rulemaking or include them in another rulemaking with an accompanying explanation of the reasons, expected costs, and expected benefits.

GPA Midstream urges PHMSA to remove the proposal to require MOC for pipelines other than those covered by the Integrity Management program.

Finally, as stated above, if the requirement for MOC is to remain, §§192.13(d), and 192.9(d)(1) should be modified and §192.9(c) should be corrected to accurately reflect that §192.13(d) is not applicable to gathering pipelines.

D. Subparts C and D

§192.127 Records: Pipe Design

§192.205 Records: Pipeline Components

PHMSA has proposed to add new sections within Subparts C and D stating that certain records for transmission lines must be retained. PHMSA has provided little discussion why it believes this additional language is necessary. Because these requirements are not excluded from the requirements applicable to gathering lines, they will apply to both gathering and transmission pipelines. PHMSA has also failed to address the retroactive applicability of these provisions to pipelines existing before the effective date of the final rule. Although transmission pipeline operators have been required to meet substantive design, installation, construction, inspection, and testing requirements for decades, there has been no affirmative requirement to retain detailed and comprehensive records. Operators of regulated gathering lines have not been required to meet all underlying requirements in Subparts C and D for pipelines put in service before March 15, 2007, and operators of newly regulated Type A, Area 2 lines may not have created or maintained on a consistent basis records of this type prior to the effective date of this rule.

GPA Midstream recommends PHMSA eliminate this proposal, as well as the proposed §192.205, because they are unnecessary and, as written, have retroactive application.

E. Subparts E and F

§ 192.227 Qualification of welders

§ 192.285 Plastic pipe: Qualifying persons to make joints

PHMSA has proposed to add new paragraph (c) in §§192.227 and 192.285 requiring certain records for transmission lines be retained for the life of the pipeline. PHMSA has extrapolated from Section 23 of the 2011 Act to support this new requirement. Section 23 of the Act requires the Secretary of Transportation to require verification of records used to establish MAOP to ensure they accurately reflect the physical and operational characteristics of certain pipelines and to confirm the established MAOP of the pipelines. However, individual qualifications for welders, welding operators, and plastic pipe joiners, while necessary for proper construction of a pipeline, are not relevant to the establishment of MAOP. The factors necessary

to establish a MAOP are clearly stated within §192.619 and include identification of the materials used and the demonstration of a successful post construction pressure test. For steel pipelines with an MAOP greater than or equal to 20% of SMYS, the additional records required by §192.243 are applicable.

GPA Midstream urges PHMSA to delete both of these proposed record keeping requirements as neither are relevant when demonstrating the proper establishment of MAOP nor has PHMSA demonstrated a need or provided expected costs or benefits in the RIA. In addition, these requirements may only apply to pipelines constructed or replaced after the effective date of this regulation.

F. Subpart G

§ 192.319 Installation of pipe in a ditch

PHMSA has proposed a new paragraph in §192.319 to require inspection via ACVG/DCVG of all transmission lines as a post construction activity. GPA Midstream has several comments regarding this proposal.

In defining the compliance activities required for Type A, Area 1 gathering lines (§192.9(c)), PHMSA has stated §192.319 is not applicable. While GPA Midstream's membership is not opposed to this in principle, GPA Midstream does not believe that PHMSA intended to exempt gathering lines from the current requirements to provide proper support and protect pipe during the backfill process. Conversely, PHMSA has provided no exception for all new, relocated, replaced, or otherwise changed Type A, Area 2 or Type B gathering lines. Type A, Area 2 and Type B gathering are subject to all transmission regulations for each segment that is new, relocated, replaced, or otherwise changed, as provided in §192.9(d)(1).

PHMSA has not adequately justified this new requirement. One failure out of the thousands of miles of pipe per year that are installed hardly demonstrates the need to promulgate new regulations. In fact, GPA Midstream contends that the regulations already address the issue adequately in the existing §192.319(b)(2) and isolated events are an inspection and enforcement issue, not cause for a new regulation.

PHMSA has not taken the cost impact of the new requirement into account within the RIA. PHMSA states in the RIA (page 106): "The compliance costs for new, replaced, or changed pipelines are insignificant because operators would be able to account for compliance with PHMSA requirements as part of the decision-making and planning process." While it is true that such costs can be accounted for in the planning process, these are nonetheless real costs which have not been factored into the overall cost of the rule as proposed. Moreover, GPA Midstream disagrees with PHMSA's assertion that the costs to comply with the proposed §192.319(d) will be insignificant. Even PHMSA, in the RIA for the newly proposed §192.465(f), states "Coating survey costs range from \$2,000 to \$50,000 per mile depending on

several factors: the environment, traffic control, and the amount of miles being surveyed.” Since proposed new §192.319(d) would require coating repairs for any moderate to severe coating damage, as demonstrated by voltage drops, GPA Midstream is unclear how PHMSA can consider this a negligible cost. The type of installation method and location may make this requirement infeasible or impracticable, such as horizontal directionally drilled locations under rivers, lakes, and multi-lane interstate highways. PHMSA has provided for no alternatives or exceptions.

GPA Midstream believes PHMSA should revise the proposed insertion of §192.319(d) to provide exceptions for areas where conducting tests are impracticable and include a minimum mileage criteria, one mile or more of line pipe.

G. Subpart I

§ 192.461 External corrosion control: Protective coating

PHMSA has proposed to include a new paragraph (f) in §192.461, which will require each operator of a transmission line to perform a coating assessment and possible remediation for any segment of pipeline 1000 feet or greater in length that has been repaired or replaced. While PHMSA provided exceptions for Type A, Area 1 gathering lines in §192.9(c), the same relief was not provided for in §192.9(d)(2). Type A, Area 2 and Type B gathering are subject to all transmission regulations for each segment that is new, relocated, replaced, or otherwise changed per §192.9(d)(1) and must follow the corrosion control requirements per §192.9(d)(2). This impact has not been taken into consideration within the RIA.

If it was PHMSA’s intent to exclude gathering from this requirement, then §192.461(f), 192.9(d)(2), or both should be modified to accurately reflect the intentions. If inclusion was done intentionally, then GPA Midstream objects to this proposed regulation because no cost consideration is included in the RIA.

PHMSA should adjust the cost figures for both ACVG/DCVG coating assessments and close interval surveys in class 1 & 2 areas to reflect a more realistic minimum of \$8000 per mile.

§ 192.465 External corrosion control: Monitoring and remediation

The NPRM contains a proposal to revise paragraph (d) and introduce a new paragraph (f) in §192.465. The revision to paragraph (d) appears fairly consistent with PHMSA’s Guidance for Corrosion Control,³² which states: “The definition of “prompt” will vary with the circumstances. Enforcement should be sought when the investigator is convinced that corrective action was not initiated or started in a timely manner.” The guidance continues: “These time frames should give consideration to the population density and environmental concerns of the

³²http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_8E901C2708D127EB2E23FDD7227D4DEF4B910700/filename/Corrosion_Enforcement_Guidance_Pt192_012213.pdf

area that could potentially be affected by release of gas. They may also consider climatic conditions, availability of material, workloads, and an estimate of a relative rate of detrimental corrosion. As a rule of thumb, the OPS would expect that, *under normal conditions* (GPA Midstream emphasis), the operator should have the evaluations and decisions made and action started within a few months, proportionally less where required monitoring is less than a year or where deficiencies could result in an immediate hazard to the public, and correction completed by the time of the next scheduled monitoring³³.”

GPA Midstream is concerned with the loss of flexibility for extenuating circumstances and for items with short monitoring periods that cannot be remediated quickly, such as backordered replacement parts for a rectifier or the ability to obtain the necessary permits or right-of-way to replace a ground bed. Where the enforcement guidance found delays permissible provided the operator can demonstrate it is taking actions to resolve the problem in a timely fashion, the proposed rule fails to provide flexibility.

As proposed, PHMSA will require a coating assessment be conducted for every low reading found during the monitoring process. However, some low readings result from an easily identified problem that can be readily corrected, such as a loose connection on a test lead, a bond that has lost connection, damage to a rectifier is identified, or power to a rectifier is disconnected. In those circumstances, a coating assessment may be redundant or unnecessary.

PHMSA’s cost estimation in Table 3-71 of the RIA associated with conducting these coating surveys uses \$200 per occurrence for segments in Class 1. For the vast majority of Class 1 pipelines, this cost does not even cover the drive time for a service provider to reach the location. The actual price, according to a cathodic protection service provider³⁴, to assess a 1000’ segment in a Class 1 location would run approximately \$6,500 and, for comparison, assessment of one mile of 12” pipeline (the bid he was working on when contacted) would be \$7,950. Much of the cost is in the associated mobilization, demobilization, and travel. Thus, for the estimated 240 PHMSA-anticipated events, the cost will be a minimum of \$1.56 MM and not the \$298,000 included in the RIA for transmission mileage. As read to include Type A, Area 2, assuming the same 1% non-compliant as PHMSA’s RIA, the cost added to gathering is \$4,468,685.

GPA Midstream requests PHMSA use the guidance material it has in place as a model to revise the language to accommodate extenuating circumstances without the undue burden of requesting relief via the special permit process.

If it was PHMSA’s intent to exclude gathering from this requirement, then §192.465(f), 192.9(d)(2), or both should be modified to accurately reflect the intentions. If this was done

³³ PHMSA Part 192 Corrosion Enforcement Guidance – Pages 61-62:
http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Pipeline/Corrosion_Enforcement_Guidance_Pt192_012213.pdf

³⁴ Telephone interview May 23, 2016

intentionally, then GPA Midstream challenges this point because no cost consideration is included in the RIA.

PHMSA should adjust the cost figures for close interval surveys in class 1 & 2 areas to reflect a more realistic minimum of \$8000 per mile for all mileage targeted for inclusion in this proposed rule.

GPA Midstream urges PHMSA to eliminate the mandatory and unnecessary cost associated with these assessments when the cause for low readings is readily determinable.

§ 192.473 External corrosion control: Interference currents

PHMSA has proposed the addition of a new paragraph (c) and sub-paragraphs (1)-(3) to §192.473, which is stated to be applicable to transmission. However, as with the above, exceptions for Type A, Area 1 were included but similar exceptions for Type A, Area 2 or Type B gathering was not expressly provided under 192.9(d).

If it was PHMSA's intent to exclude gathering from this requirement, then §192.473(c)(1)-(3), 192.9(d)(2), or both should be modified to accurately reflect the intentions. If inclusion was done intentionally, then GPA Midstream objects to this requirement on the grounds that no cost consideration related to gathering pipelines is included in the RIA.

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation

PHMSA has proposed to include a new §192.478, which will require each operator of a transmission line to develop and implement a program for evaluating and monitoring conditions which may be indicative of a potential internal corrosion threat. While PHMSA provided exceptions for Type A, Area 1 gathering lines in §192.9(c), the same relief was not provided for in §192.9(d)(2). Type A, Area 2 and Type B gathering are subject to all transmission regulations for corrosion control per §192.9(d)(2). This impact has not been taken into consideration within the RIA.

For any population of pipeline PHMSA intends to apply this requirement, GPA Midstream believes there is additional clarification warranted. In the proposed new §192.478(b)(1)-(3), it is unclear if PHMSA expects all of the listed activities to be performed concurrently, or if PHMSA intended for operators to determine which of the actions listed in subparagraphs (1) and (2) are needed for their systems, followed by the evaluation required by the proposed subparagraph (3).

PHMSA has estimated only thirteen new installations will be required in Class 1 locations. PHMSA bases this assumption on another assumption that most interstate operators have these in place already. No mention or consideration of intrastate pipelines is given. The \$10000 per installation may cover the cost of equipment if power, cell service, and other necessary infrastructure are available. If that is not the case, as is likely in Class 1 locations, then

costs can escalate dramatically. PHMSA estimates no annual costs for the required evaluations. This is hardly accurate. Since PHMSA expects operators to “evaluate the partial pressure of each corrosive constituent by itself or in combination to evaluate the effect [.]” this cost could escalate into thousands of dollars per year for those operators which have multiple input points, such as in producing regions of the country. Using PHMSA’s rate for a manager, and assuming ten input locations per year that must be reviewed, the annual cost for the company will be nearly \$7000 per year. Assuming forty companies are impacted to this level, operators will incur another \$4.2 MM for the 15-year period which PHMSA has not factored into its analysis.

The proposed §192.478(c) is duplicative of the existing §192.477 and unnecessary. The proposed §192.478(d) is also duplicative of the requirements in the proposed §192.478(b)(3) and existing §192.477 and unnecessary.

PHMSA must modify the final RIA to reflect the recurring costs associated with the proposed required monitoring and evaluation for conditions which may pose an internal corrosion threat.

If it was PHMSA’s intent to include gathering in this requirement, GPA Midstream objects to this requirement on the grounds that no cost consideration related to gathering pipelines is included in the RIA.

PHMSA should eliminate the duplication created by the proposed §129.478(b)(3) and §129.478(d).

§ 192.493 In-line inspection of pipelines

PHMSA has proposed to require adherence to three industry consensus standards, API STD 1163, *In-line Inspection Systems Qualification Standard*; ANSI/ASNT ILI-PQ-2005, *In-line Inspection Personnel Qualification and Certification*; and NACE SP0102-2010, *In-line Inspection of Pipelines* when conducting in-line inspection of pipelines required by this part.

GPA Midstream has commented in greater detail on this topic under the heading for Section §192.7.

GPA Midstream stands with its original comments filed in 2012 that PHMSA should not incorporate the standards by reference, but should make reference to them as guidance documents. In the alternative, GPA Midstream urges PHMSA to at least incorporate references to the more recent versions of the two standards.

H. Subpart J: Test Requirements

§192.503 General Requirements

PHMSA is proposing several modifications to establishment, reestablishment, and verification of MAOP’s, which are addressed in other locations within this document. As part of that larger initiative, PHMSA is proposing to modify §192.503(a)(1) by inserting references to

the proposed new §§192.620 and 192.624 to make the “link” between the requirements. While this does provide some clarity, we are slightly concerned it may create the expectation that all three referenced Sections apply.

GPA Midstream recommends the following revisions to this section:

- (1) It has been tested in accordance with this subpart and §§192.619, 192.620 or 192.624, as applicable, to substantiate the maximum allowable operating pressure; and ...

§ 192.506 Transmission lines: Spike hydrostatic pressure test for existing steel pipe with integrity threats

PHMSA has proposed to include a new Section to the pressure testing Subpart. The applicability is stated as:

- (a) Each segment of an existing steel pipeline that is operated at a hoop stress level of 30% of specified minimum yield strength or more and has been found to have integrity threats that cannot be addressed by other means such as in-line inspection or direct assessment must be strength tested by a spike hydrostatic pressure test in accordance with this section...”

GPA Midstream finds the wording as proposed problematic, because all pipelines have integrity threats. Most would consider Part 192 a “risk control” document designed to address such threats through a variety of controls implemented in each phase of a pipeline’s life, starting with the design and materials that may be used and continuing through operations and maintenance. As identified in other portions of this proposal, PHMSA is prescribing use of a spike hydrostatic pressure test for certain threats and in certain circumstances. These requirements appear in §§192.624(c)(1)(ii), 192.921(a)(3), 192.929(b)(4(ii), and 192.937(c)(3), which all contain references back to section 192.506. Providing direct references to these sections in §192.506(a), would clarify the relationship among these sections and section 192.506 and eliminate any suggestion that section 192.506 creates a separate requirement to conduct spike hydrostatic testing. PHMSA recently clarified that it does not intend to apply § 192.506 to gathering line operators in a series of webinars conducted after the publication of the NPRM. GPA Midstream appreciates that clarification and believes the information provided above demonstrates why PHMSA should make additional changes to the proposed regulation before issuing the final rule.

GPA Midstream’s comment on this paragraph is not to be taken as an endorsement of this proposal, but simply a request for clarification should PHMSA deems it appropriate to keep this Section in the final rule.

GPA Midstream believes including the spike test requirement in §192.506 is misplaced. Subpart J establishes minimum leak test and strength test requirements for pipelines post-construction, before they may be put into service and the test results are used to establish the original MAOP of the pipeline. As proposed, PHMSA is attempting to introduce an “integrity management” assessment method into this section, even though this approach is at best superfluous in the context of the initial testing required for pipelines at the beginning of their lifecycle.

GPA Midstream supports the comments on the remainder of this Section as submitted by the Interstate Natural Gas Association of America (INGAA) and the American Petroleum Institute (API).

I. Subpart L: Operations

§ 192.605 Procedural manual for operations, maintenance, and emergencies

PHMSA has proposed to revise §192.605(b)(5) to include more words pointing to the requirements for overpressure protection and the limitations imposed by §192.201. The current regulation (§192.605(b)(1)) states, in part: “The manual... must include procedures for the following, if applicable, to provide safety ...

(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and Subpart M of this part.

GPA Midstream disagrees with PHMSA’s assertion³⁵ that current regulation “does not prescribe this aspect of the procedural controls.” The references to Subpart L and Subpart M incorporate all of the references PHMSA has proposed in the revision, and existing section 192.605(b)(5) already contains an indirect reference to section 192.201. GPA Midstream views this revised subsection as redundant and unnecessary.

PHMSA should retract this proposed revision as duplicative of current requirements.

§ 192.607 Verification of Pipeline Material: Onshore steel transmission pipelines

PHMSA is proposing that each segment of onshore, steel, gas transmission pipeline that does not have reliable, traceable, verifiable, and complete material documentation records for line pipe, valves, flanges, and components which is located in an HCA as defined in §192.903 or is in a Class 3 or 4 location follow the prescriptive requirements contained in the remainder of the Section. PHMSA has not included this section in the list of exemptions applicable to Type A, Area 1 gathering, nor from the requirements applicable to new, replaced, relocated or changed Type A, Area 2 and Type B gathering. Section 23 of the Act clearly states that its mandate is applicable to interstate and intrastate gas transmission pipelines. GPA Midstream is certain that most members of Congress would not be aware that Part 192 requires many gathering lines (currently only Type A in Class 2, 3 and 4 locations) to meet the requirements applicable to transmission pipelines. PHMSA indicates in the RIA that 4,363 miles of pipeline lack RTVC records and are therefore subject to this proposed rule. The data was taken from 2014 PHMSA Annual reports 7100.2.1. Part Q of that form and accompanying instructions are clear that only transmission data was reported and therefore only transmission pipelines lacking RTVC records are considered in the RIA.

GPA Midstream questions whether the confidence levels proposed for ultimate tensile strength, Charpy v-notch toughness, and chemical composition can be achieved using

³⁵ Vol. 81, No. 68: Page 20811

nondestructive testing (“NDT”) methods. If such confidence levels are not achievable, especially over repeated testing prescribed by the proposed rule, then it is inappropriate for PHMSA to consider any cost savings derived from these methods as “savings” when compared to the alternative destructive testing methods.

GPA Midstream also questions the value of performing chemical analysis, except as one more extreme hurdle that may confirm a manufacturing standard or a general manufacturing era. GPA Midstream also questions whether there is value in determining the condition of the weld bevels on valves. PHMSA has identified no incidents or issues arising from the lack of these data points. Is PHMSA requiring collection of data for data analysis purposes, rather than actual correlation to risk based on known events or conditions?

There is no consideration given in the RIA for the costs associated with determining properties on valves and fittings as separate items. If these were included in the overall cost estimate, then those costs are significantly underestimated, especially since these features are at fixed locations and there is little or no flexibility in choosing locations to perform the necessary excavations for a testing and assessment program.

Benefits cited by PHMSA in the RIA are derived from “savings” associated with not carrying out destructive testing the pipe pursuant to §192.107, which really only points to tensile tests, as weldability is already proven. All remaining tests proposed are beyond those specified in §192.107 so GPA Midstream questions how PHMSA can claim any savings for collecting additional data that would not be obtained or otherwise required.

PHMSA recently clarified that it does not intend to apply § 192.607 to gathering line operators in a series of webinars conducted after the publication of the NPRM. GPA Midstream appreciates that clarification and believes the information provided above demonstrates why PHMSA should make additional changes to the proposed regulation before issuing the final rule.

For GPA Midstream’s comments on the introduction of the term “reliable” see the comments for Section §192.13(e).

GPA Midstream urges PHMSA to clearly state that this proposal is not applicable to any gathering lines. If it was PHMSA’s intent to subject gathering to this requirement, then GPA Midstream contends that this is a gross expansion of the requirements set forth in the Act which PHMSA used as justification.

PHMSA has not given consideration for any costs for operators of gathering lines to comply with this proposal in the RIA. Furthermore, PHMSA’s cost estimates rely on dubious assumptions regarding the impact of current destructive testing obligations

GPA Midstream supports the challenge related to the validity of the costs and benefits for this Topic as raised by the American Petroleum Institute and the Interstate Natural Gas Association of America.

§ 192.613 Continuing surveillance

GPA Midstream generally supports what it believes to be the intent behind PHMSA's proposal and notes that PHMSA appears to have taken into consideration comments filed on the similar proposal set out in the NPRM titled "Safety of Hazardous Liquids Pipelines."³⁶

However, it does not appear that PHMSA factored in the impact to Type A, Area 1 gathering costs when preparing the RIA. There were 250 operators that reported Type A gathering mileage on the Form 7100.2.1 in 2014, and because this requirement is not excluded from the obligations applicable to Type A, Area 1 gathering pipelines, GPA Midstream believes that PHMSA has not accurately estimated the costs of this requirement as applied to gathering lines.

PHMSA must factor this cost data in when revising the RIA to accurately reflect the cost impacts of this proposal.

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines

PHMSA is proposing a major change to the requirements of §192.619 with the addition of new paragraph (e) and its subparagraphs. PHMSA has proposed lesser modifications to §192.619(a)(2) and (3). Within the changes to §192.619(a)(2) and (3), PHMSA has proposed new MAOP compliance dates and methods for gathering which becomes regulated as a result of this rulemaking. This is consistent with the process used in the rulemaking which affected MAOPs for gathering in 2006. More significantly, PHMSA is requiring newly regulated gathering pipelines—Type A, Area 2 gathering lines—to establish MAOP according to §192.619 within a year of the effective date of the proposed regulation, or within a year of becoming subject to the regulation. As previously stated, GPA Midstream believes that not all operators of Type A, Area 2 gathering pipelines will have records sufficient to support MAOP in accordance with section 192.619, because such pipelines were not required to establish MAOP prior to the effective date of this rule. Operators may not possess a complete history of operating pressures during the five year period preceding the effective date of the rule. Finally, PHMSA has not included a provision for pipelines currently classified as gathering which are reclassified as transmission as a result of this rulemaking.

GPA Midstream is concerned that proposed new §192.619 (e) does not provide any exception for gathering pipelines. This proposed subsection is written to apply to onshore steel transmission pipelines, but it is not an exception to the transmission line requirements applicable to gathering lines set forth in section 192.9(c) or (d), and section 192.9(d)(2) specifically requires that operators of Type A, Area 2 and Type B gathering lines establish MAOP pursuant to 192.619. Yet, PHMSA has clearly not accounted for applying this provision to any gathering lines within the RIA. PHMSA used Parts Q and R of the 7100.1.2 for years 2013 to 2015 to

³⁶ Pipeline Safety: Safety of Hazardous Liquid Pipelines RIN 2137-AE66 [Docket No. PHMSA-2010-0229]

identify affected mileage for transmission pipelines only. Section 23 of the 2011 Act requires verification of MAOP and allows reconfirmation of MAOP where records are insufficient as expeditiously as economically feasible, but this mandate is expressly applicable to transmission pipelines. Any application to gathering is far beyond the scope of the Act and congressional intent. GPA Midstream also notes that PHMSA's proposed MAOP regulations, as stated in §§192.619(e) and 192.624, go far beyond the congressional mandate even for transmission lines, as discussed in the next comment. The permitted methods for establishing MAOP are far from economically feasible, and they cannot be performed expeditiously. The six permitted methods listed in §192.619(e) do not allow inline inspection as a contributing factor in establishing MAOP, despite PHMSA's statements indicating a preference for ILI over pressure testing to demonstrate integrity. Further, as described in §192.624(c)(3), one of the methods for establishing MAOP relies on the records required by § 192.607, which retroactively imposes extensive materials records and data collection requirements.

Finally, §192.619(f) requires operators to maintain RTVC records for the life of the pipeline, including design, construction, operation, maintenance, inspection, testing, material strength, pipe wall thickness, seam strength and other related data. Although PHMSA does not list operating history in this requirement, GPA Midstream assumes that if an operator has relied on operating history to establish MAOP, pursuant to 192.619(c), then such records are also subject to the RTVC standard and must be maintained for the lifetime of the pipeline.

PHMSA recently clarified that it does not intend to apply the MAOP verification requirements in § 192.624 to gathering line operators in a series of webinars conducted after the publication of the NPRM. GPA Midstream appreciates that clarification and believes the information provided above demonstrates why PHMSA should make additional changes to § 192.619 before issuing the final rule.

GPA Midstream urges PHMSA to clearly state that this proposal is not applicable to any gathering lines. If it was PHMSA's intent to subject gathering to this requirement, then GPA Midstream contends that this is a gross expansion of the requirements set forth in the Act which PHMSA used as justification.

PHMSA has not given consideration for any costs for operators of gathering lines to comply with this proposal in the RIA.

GPA Midstream supports the challenge related to the validity of the costs and benefits for this Topic as raised by the American Petroleum Institute and the Interstate Natural Gas Association of America.

§ 192.624 Maximum allowable operating pressure verification: Onshore steel transmission pipelines

GPA Midstream's comments for proposed §§192.607 and 192.619(e) are echoed for the proposed §192.624. No exceptions for gathering have been provided and no cost considerations corresponding to gathering have been included in the RIA.

Proposed new §192.624(a)(1) will subject a pipeline to the requirements of this section if the pipe has experienced an incident since its most recent pressure test if the cause was attributable to one of a laundry list of causes. This particular issue was not identified in Section 23 of the 2011 Act as justifying the need to reconfirm MAOP, and PHMSA's statements in the preamble of the Notice indicate that PHMSA drafted this provision with the intent to correct or confirm MAOP in older, pre-1970 lines for which MAOP was established on the basis of operating history or pressure tests that do not meet Subpart J requirements and that subsequently experienced a safety incident. However, PHMSA has not distinguished between these situations and those pipelines for which the defect or incident may have occurred decades ago but where the "cause" is not known today, either as the result of lost records or simply less detailed investigation at the time.

As noted elsewhere, PHMSA has incorporated references to other sections of Part 192 in proposed new §192.624, some of which have a retroactive impact on existing pipelines. Proposed new §192.624(a)(2) references sufficiency of test records, including testing pursuant to sections 192.505 and 192.507, as well as proposed new section 192.506, which requires a spike test—a requirement for transmission pipelines which is not now and has never been a requirement. By incorporating a reference to a new requirement in the determination of the sufficiency of records to verify MAOP, PHMSA is retroactively applying the new spike test requirement to certain lines through MAOP verification, which is prohibited by 49 U.S.C. §60104 (b). This retroactive application is also prohibited with respect to §§192.505 & 192.507, to the extent required for transmission pipe pressure tested prior to July 1, 1965.

The scope of proposed §192.624 goes far beyond the scope expressed in Section 23 of the 2011 Act. PHMSA was directed to "issue regulations for conducting tests to confirm the material strength of previously untested natural gas transmission pipelines located in high-consequence areas and operating at a pressure greater than 30 percent of specified minimum yield strength." PHMSA's proposal seeks to include all transmission lines (and, as written, gathering lines), even those that have an MAOP of less than 30% SMYS, or are located outside Class 3 and 4 locations or high consequence areas in Class 1 and 2 locations. This, too, appears to be a considerable expansion of the Congressional mandate.

PHMSA is proposing in new §192.624(b) that operators with pipe subject to the requirements of this section will have one year to develop a plan and, effectively, 14 years to complete the required testing or evaluations for all pipelines. This schedule does not take into

account the time period needed to identify MCAs—as discussed earlier in these comments, identification of MCAs cannot be achieved easily or quickly, as the rule is currently written. MCAs must be identified prior to the development of a testing and assessment plan pursuant to §192.624(b). Thus, realistically, an operator may need a year to identify all MCAs, and another year to identify those MCAs which contain pipelines covered by §192.624 and develop the testing and evaluation plan. If the operator is allowed two years to carry out this preliminary work, the operator would be left with only 6 years to complete testing and evaluation of the first half of its covered pipelines. PHMSA should adjust the timeframes for testing and assessments to ten and twenty years after plan development.

PHMSA based its RIA cost estimates on costs associated with pipelines operated at greater than 30% SMYS (Table 3-20, page 45). However, nothing in this proposed section indicates that its applicability is limited to such pipelines. In Table ES-2, PHMSA included a row of data for pipe operated at pressures between 20% and 30% of SMYS, showing an estimated 2,817 miles impacted by the proposed regulation. This points to a disconnect between the analysis and the actual impact of the proposed regulation, which is not limited to the smaller population of transmission pipelines contemplated by the 2011 Act or in the RIA.

Method 5 for small diameter, low stress is completely baffling. It appears that PHMSA is proposing some of the most restrictive criteria on the lowest risk pipelines. For these low risk lines, PHMSA will require: lowering the MAOP, conduct External Corrosion Direct Assessment (“ECDA”) and Internal Corrosion Direct Assessment (“ICDA”) investigations, investigate for cracks and crack-related defects, conduct patrols at a frequency that is ten times more than is currently required, conduct leakage surveys at a frequency that is ten times more than is currently required, implement an odorization program, and possibly employ the fracture mechanics requirements.

GPA Midstream urges PHMSA to clearly state that this proposal is not applicable to any gathering lines. If it was PHMSA’s intent to subject gathering to this requirement, then GPA Midstream contends that this is a gross overextension of the requirements set forth in the Act.

PHMSA has not given consideration for any costs for operators of gathering lines to comply with this proposal in the RIA, and has included only a subset of transmission lines in its analysis.

GPA Midstream supports the challenge related to the validity of the costs and benefits for this Topic as raised by the American Petroleum Institute and the Interstate Natural Gas Association of America.

GPA Midstream urges PHMSA to eliminate any MAOP validation requirements for low stress, class 1 and 2 transmission pipelines.

K. Subpart M: Maintenance

§ 192.710 Pipeline assessments

In section 192.9(d), PHMSA excepted Type A, Area 1 gathering pipelines from this requirement, but no other regulated gathering lines. GPA Midstream recommends that PHMSA expressly extend the exception to Type A, Area 2 and Type B gathering pipelines. GPA Midstream believes that this is consistent with the language in 192.9(d)(2), which states that the applicable transmission requirements are “...the design, installation, construction, *initial* inspection, and *initial* testing...” requirements applicable to transmission pipelines that are also applicable to gathering pipelines.

PHMSA proposes to require operators of transmission lines in Class 3 or 4 and in the new proposed MCAs to conduct assessments within fifteen years (15) and then at intervals not to exceed twenty years (20). PHMSA has provided no reasoning for the selection of the proposed timeframes to complete the initial assessments or reassessments. PHMSA has proposed to allow the use of prior assessments meeting the requirements of Subpart O, but only if that assessment was performed using ILI. This is essentially establishing a higher standard for Non-HCA pipe than is required for pipe in an HCA.

PHMSA stated³⁷ in the preamble that requiring all IM elements for MCA’s would result in significant costs. While it is true that risk analysis is costly, GPA Midstream contends that PHMSA has simply replaced that cost with the cost of having to run every tool imaginable for every threat, existing or not. PHMSA also requests input³⁸ regarding the MCA definition and “limits on the categories of pipeline to be regulated within this new area.” For GPA Midstream’s comments on the proposed definition of MCA, please refer to that location above. Within the 2011 Act, Section 5(b)(5) directs PHMSA to consider “the most effective and efficient options for decreasing risks to an increasing number of people...” None of the pipeline failures presented as evidence for the need for this proposed rule by PHMSA are smaller than twenty inches in diameter. Establishing a threshold level of pipelines greater than sixteen inches (16”) diameter in an MCA would permit targeting of resources to pipelines which pose more actual risk to the public than the current scope of this proposed rule, which covers all transmission lines (assuming PHMSA removes uncertainty as to gathering pipelines) located within MCAs.

As noted earlier, PHMSA has not acknowledged or provided any timelines for initial identification of MCAs, nor communicated any expectations for updates or recurring investigations. As previously discussed, the cost of this identification is not negligible as PHMSA claims in the RIA.³⁹ PHMSA has not elaborated on its expectations for timing of

³⁷ Id: 46

³⁸ Id: 48

³⁹ Id: 32

pipeline assessments or reassessments of previously assessed areas if a new MCA is identified. This too has tremendous cost implications that have not been taken into consideration.

In the proposed §192.710(c)(4), PHMSA proposes to allow excavation and *in situ* examination. However, PHMSA has not provided any guidance or insight into its expectations. A strict reading would imply the operator must excavate the entire length of the line which is in or could affect the MCA, effectively taking it out of service for the duration of the assessment, even if no corrective action or repair is necessary.

In proposed §192.710(c)(6), PHMSA proposes to allow Direct Assessment (“DA”) if it “is not practical to assess (due to low operating pressures and flows, lack of inspection technology, and critical delivery areas such as hospitals and nursing homes) using the [stated] methods...” It is not clear as written if the other assessment technologies can only be used in critical delivery areas, or whether other constraints, such as low operating pressures and inspection technology limitations can be the basis to select direct assessment. GPA Midstream urges PHMSA to clarify that operators may use direct assessment if warranted by practical limitations such as described or by the need to avoid interruptions in service to critical delivery areas.

In the RIA⁴⁰ PHMSA projects a fairly substantial use of DA and possibly, *in situ* examinations, but as discussed above, it is not clear whether use of DA is unlikely due to restrictions. Moreover, the costs to retrofit to accommodate ILI or to perform pressure tests are grossly underestimated.

In the proposed §192.710(c)(8), PHMSA proposes to require the lowest risk pipe (less than or equal to 8” and less than 30% SMYS) to use a prescriptive regimen of assessments, ECDA and ICDA, without deviation. It does not make sense to GPA Midstream why use of this subset of “tools” in its entirety would be required, instead of permitted for use as appropriate, for these lower risk pipelines.

GPA Midstream requests PHMSA to explicitly list the exemption for Type A, Area 2 gathering subject to §192.9(d)(2), either in §§192.9, 192.710, or in both locations.

GPA Midstream urges PHMSA to require the proposed set of assessments to be applicable to steel transmission lines greater than 16” in diameter to assure resources are targeted at the pipelines that pose a greater risk.

PHMSA must clearly define timeframes in the rule for identifying MCA’s and how to handle newly identified MCA’s. GPA Midstream supports the timetables we have provided.

The associated costs for this ongoing identification MUST be clearly identified in the RIA.

⁴⁰ Id: 55

PHMSA should more clearly state the types of highways included in the MCA definition are those designated as part of the US Interstate system.

PHMSA should clarify its expectations for in situ examinations and Direct Assessment.

PHMSA should modify §192.710(c)(8) as indicated below:

(8) For segments with MAOP less than 30% of the SMYS, **in lieu of the methods prescribed in (1)-(7) above,** an operator ~~must~~ **may** assess for the threats of external and internal corrosion, as follows:

GPA Midstream supports the comments and recommendations submitted on this topic by the INGAA, API, and TPA.

§ 192.713 Transmission lines: Permanent field repair of imperfections and damages

As proposed, any and every dent, regardless of clock position on the pipe and regardless of amount of deflection or operating stress of the pipeline, is considered an immediate repair if there is any indication of metal loss. GPA Midstream is not aware of any scientific basis that warrants this type of broad-brushed classification.

PHMSA is permitting evaluations required by the proposed §192.713(f) if “confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection and in metallurgy and fracture mechanics for accuracy for the type of defects and pipe material being evaluated.” GPA Midstream questions why these same criteria are not permitted in §192.607(d)(3)(iv).

While PHMSA included estimates for cost of repairs on a “per repair” basis, it has not accounted for the costs associated with scheduling and mobilization. By placing prescriptive requirements in place, operators will likely incur more costs for repairs as crews are required to “hop scotch” in order to meet deadlines for certain types of anomalies.

GPA Midstream supports the comments and proposed course of action filed by API and INGAA regarding this broad expansion of prescriptive requirements for repairs outside of HCA’s.

L. Appendix A: Records Retention Schedule for Transmission Pipelines

The proposed §192.13 (e)(1) creates a new requirement to maintain documentation in accordance with the newly proposed Appendix A. Appendix A attempts to summarize each section of Part 192 applicable to a gas transmission line that requires the generation of documentation, as well as the retention period for which this documentation must be retained.

However, Appendix A as proposed, creates an enormous documentation burden beyond what currently already exists, in many cases creating conflicts with existing requirements in Part 192. For example, there are at least 18 instances where Appendix A would require documents to be

retained for the life of the pipeline, even though current regulation requires retention far below this standard (usually 5 years). In addition, there are at least three articles of documentation created by Appendix A which do not currently exist, including one of which requires documentation for an activity that is not required in Part 192.

This massive expansion of documentation requirements is being proposed with little to no discussion in the NPRM, no consideration of costs provided for in the RIA, and without resolving the conflicts it creates with existing language within Part 192. Also, the majority of records which are being proposed to be kept for the life of the pipeline provide no real value beyond a few years. They are not pieces of information that would likely be used to make integrity or operational decisions many years or many decades after the fact. However, it would create a tremendous burden for the storage and maintenance of all this data.

As an illustration of this point, §192.491(c) states: “Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained *for at least 5 years*, except that records related to §§192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service”. However, Appendix A proposes to require that each test, survey, and inspection conducted related to §§ 192.459, 192.461, 192.467(d), 192.473, 192.477, and 192.478 be maintained for the life of the pipe. These requirements directly conflict with the existing §192.491(c). The NPRM does not address the technical justifications for these new requirements, nor does it resolve the conflict with the existing §192.491.

Also, Appendix A proposes to require maintaining documentation demonstrating that the compliance dates of §192.452 were met. The current regulation does not specify a retention period for this documentation.

GPA Midstream urges PHMSA to eliminate inclusion of the Appendix at this time and conduct a more thorough examination of the recordkeeping requirements required by the regulations and address any potential inclusion of a table of this nature in a future rulemaking.

If PHMSA does not eliminate this Appendix, PHMSA must factor this cost data in when revising the RIA to accurately reflect the cost impacts of this proposal.

GPA Midstream appreciates the opportunity to comment on the notice and request for comments regarding “*Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines*” published by PHMSA in the April 8, 2016 Federal Register. GPA Midstream has provided comments and recommendations that will create a practical path forward to meet the continued need to achieve US energy independence while ensuring the infrastructure used to transport it continues to do so in a safe, economical manner. Please contact me at (202)279-1664 or mwhite@gpaglobal.org if GPA Midstream can be of assistance.

Sincerely,

Matthew Hite
Vice President of Government Affairs
GPA Midstream Association

Attachment 3:

Gas Processors Association January 8, 2016 Comment Letter

Notice of Proposed Rulemaking, Docket No. PHMSA-2010-0229



January 8, 2016

VIA ELECTRONIC FILING

U.S. DOT Docket Management System
West Building Ground Floor
Room W12-140
1200 New Jersey Avenue, SE,
Washington, DC 20590-0001
DC 20590-0001,

Re: Docket No. PHMSA 2010 – 0229: Proposed Rule on Pipeline Safety: Safety of Hazardous Liquids Pipelines; Federal Register Vol. 80, No. 197 (Tuesday, October 13, 2015); RIN 2137-AE66

Dear Sir/Madam,

The Gas Processors Association (“GPA” or the “Association”) appreciates the opportunity to provide comments to Pipeline and Hazardous Materials Safety Administration’s (PHMSA) Notice of Proposed Rulemaking (NPRM) on Hazardous Liquids Pipeline Safety.¹

GPA is a non-profit trade organization made up of over 100 corporate members. GPA’s membership accounts for approximately 92 percent of all natural gas liquids (“NGLs”) produced by the midstream energy sector in the United States. GPA members also produce, gather, transport and market natural gas and crude oil.

On October 18, 2010 PHMSA published “*Pipeline Safety: Safety of On-Shore Hazardous Liquid Pipelines*,” Advance Notice of Proposed Rulemaking, 75 FR 63774. While GPA did not respond directly, many of its member companies are also members of API and AOPL and provided comments in the joint submittal dated February 18, 2011.

On Tuesday, October 13, 2015 a Notice of Proposed Rulemaking (“Notice”) was published in the Federal Register concerning several substantial proposed changes to the pipeline safety rules for hazardous liquids pipelines. PHMSA has grouped these proposals into seven primary categories: (1) Extend certain reporting requirements to gravity lines; (2) Extend certain reporting requirements to all hazardous liquid gathering lines; (3) Require inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events; (4) Require periodic assessments of pipelines that are not already covered under the integrity management (IM) program requirements; (5) Expand the use of leak detection systems on hazardous liquid pipelines to mitigate the effects of failures that occur outside of HCAs; (6)

¹ *Pipeline Safety: “Safety of Hazardous Liquid Pipelines,”* Notice of Proposed Rulemaking, 80 FR, 61610 (October 13, 2015).

Modify the IM repair criteria, both by expanding the list of conditions that require immediate remediation and consolidating the timeframes for remediating all other conditions, and apply those same criteria to pipelines that are not subject to the IM requirements, with an adjusted schedule for performing non-immediate repairs; and, (7) Increase the use of inline inspection tools by requiring that any pipeline that could affect a high consequence area be capable of accommodating these devices within 20 years.

GPA members have a significant interest in all aspects of the proposal. GPA has provided comments in greatest detail for those issues of greatest overall negative impact to its membership, would result in little or no safety benefit, or may be unattainable as proposed while greatly burdening PHMSA and its state partner resources in addition to the industry. Further, we are confident the actual total cost of the proposal far exceeds the \$22 million plus per year cost that will be incurred by industry as proffered by the PHMSA. Moreover, little, if any, justification has been provided to demonstrate how or why the proposed changes are reasonable or necessary for some of the proposals. For other proposals, GPA offers its support or asks PHMSA to provide further clarification in the final rule.

PHMSA has portrayed the proposed rulemaking as having seven distinct components. While this is an accurate portrayal from a purely technical perspective, many of the proposals cross over different sectors of the transportation chain and carry dramatically different effects. For these reasons, GPA has further subdivided some of the proposals and offers the following comments.

A. Addition of two New Definitions

GPA supports, with clarification, PHMSA's proposal to include two new definitions into the CFR. We do not oppose PHMSA's intent to include transportation of biofuels oversight into its regulatory program. With respect to the proposed definition of "*Significant Stress Corrosion Cracking*" ("SCC"), GPA understands PHMSA's intent to raise awareness of this potential threat. We harbor concerns over the use of the word significant even with the additional descriptions PHMSA is including. The proposed descriptors do not begin to include all of the variables which influence SCC behavior and is therefore, very incomplete for assigning an "actionable" status for all instances. The term "significant" is very subjective and, thus it is very conceivable there will be differences of opinion in the interpretation. For these reasons, we believe PHMSA should seek another "qualifying method" which can be used to identify those SCC problems that warrant the required actions in the proposed §195.422(1)(vi) and §195.452(h)(4)(E), such as those found in published standards and other available research.

B. Gathering Lines

Extension of the Reporting Requirements

PHMSA has proposed that operators of non-regulated gathering lines be subjected to the reporting requirements contained within Subpart B of 49 CFR Part 195. Within the proposal PHMSA has identified the need to modify the data collection activities associated with Annual

Reports, Safety-related Condition Reports, and Accident Reports to reflect the adjusted burden hours needed to comply with the proposal. Not mentioned is the burden associated with compliance of §§195.61 & 195.64; the requirements to obtain an Operator Identification number (“OpID”) and the ongoing costs related to changes within the system through construction or mergers, divestitures, and acquisitions. While many operators have maps of newer installations, geospatial information on legacy gathering lines may not be available. Again, no cost impacts seem to have been considered for these requirements. We assume that because these code provisions were introduced after the publication of the ANPRM, the Regulatory Impact Analysis (RIA) was not updated to reflect their inclusion. The data PHMSA would obtain by requiring the reporting of either of these provisions would not contribute in any meaningful way to making future fact-based, risk-based decisions. They should not be included in a data collection effort.

While the collection is authorized by statute as PHMSA noted in the Preamble, it should also be recognized that the GAO² report recommended the data collection be conducted “subsequent to an analysis of the benefits and industry burdens associated with such data collection.” PHMSA has stated in the NPRM that the burden created by requiring Annual Reports for gathering lines that are not currently regulated will only impact 23 operators and that “Operators currently submitting annual reports will not be otherwise impacted by this rule.” GPA disagrees with the last statement. Operators currently filing Annual Reports {OMB Control Number 2137-0614} that also have gathering that is not currently regulated will experience increased costs and burden to collect data from the “field” and incorporate it into the reporting management process. As PHMSA notes, this entails data for some 30,000 – 40,000 miles of pipeline. The largest burden will be incurred the first year, but there will be associated costs each year as systems are expanded or pipe is replaced or abandoned.

GPA supports PHMSA’s goal of collecting data necessary to make informed rulemaking decisions. We believe this can be accomplished by developing an abbreviated form which includes only the data contained in Sections A, D, H, J, N, & O of the current Annual Report (F 7000.1-1) with the addition of the M1 data fields (modified) from the Gas Transmission Annual Report (F7100.2-1). The information collected annually through this process could then be paired with Accident reporting on Form F 7000-1 (rev 7-2014). Once sufficient data is collected (e.g. a minimum of five years), PHMSA can analyze the data to determine if regulatory expansion is necessary and if so, to what degree. The reporting of safety-related conditions on a sporadic basis would likely provide little value in reaching conclusions from data driven analysis. Telephonic notice would add no value to this initiative, as very few details useful for analysis are typically available within the one hour timeframe required for telephonic notification.

While the data and cost associated with the actual filing of the report are included in the analysis, GPA feels PHMSA has neglected to account for the costs and burden associated with the initial compiling of the data needed to complete the forms. In many cases, the information

² <http://www.gao.gov/products/GAO-12-388>

may not be recorded or may not have been provided during mergers or acquisitions. PHMSA has not communicated its expectations for these situations. GPA requests that PHMSA clarify their expectations regarding the specific pipe details. If it is PHMSA's expectation that operators physically excavate to obtain the data, the costs will reach into the hundreds of millions.

GPA encourages PHMSA to undertake the modified data collection effort described above for future use in determining whether further oversight is warranted, and if so, to what degree.

Performing Assessments on Rural Gathering

PHMSA has stated it is basing its proposal to require assessments and leak detection on the findings contained in the congressionally³ mandated study titled "Review of Existing Federal and State Regulations for Gas and Hazardous Liquid Gathering Lines," that was performed by the Oak Ridge National Laboratory and published on May 8, 2015. PHMSA is proposing additional regulations to ensure the safety of hazardous liquid gathering lines. That study contained no identified shortcomings, nor drew any conclusions regarding a need to promulgate further regulations.

The RIA assumes only 8% would be pressure tested versus instrumented in-line inspection ("ILI"). The RIA makes no distinction on the ability for rural high consequence areas ("HCA") affected gathering to be subjected to ILI versus transportation lines. The RIA does not consider the mobilization costs associated with conducted assessments using ILI. Costs to conduct ILI assessments are typically presented on a per mile basis with mobilization averaged in. We assume that is the approach used in the RIA. However, mobilization costs are essentially the same for a one mile ILI run or a two hundred mile assessment. So, cost per mile for isolated short runs is significantly higher when presented on a per mile basis than the \$5150 figure used. In fact, one of our member companies has figures showing cost per mile closer to \$10,000, or at least \$200,000/20 miles of pipeline for recent assessments of rural gathering.

Regulated segments of rural gathering are defined in §195.11 in part as;

...an onshore gathering line in a rural area that meets all of the following criteria--

- (1) Has a nominal diameter from 6 5/8 inches (168 mm) to 8 5/8 inches (219.1 mm);
- (2) Is located in or within one-quarter mile (.40 km) of an unusually sensitive area as defined in § 195.6; and
- (3) Operates at a maximum pressure established under § 195.406 corresponding to--
 - (i) A stress level greater than 20-percent of the specified minimum yield strength of the line pipe

³ Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (ACT), Section 21, Gas and hazardous liquid gathering lines.

PHMSA conducted extensive analysis preceding the 2008 rulemaking⁴ to determine which rural gathering lines posed the potential to cause the most harm from a release. As a result, portions of gathering lines or gathering systems are regulated. Gathering systems tend to consist of hundreds of miles of short lines segments interconnected and used to transport product from a multitude of wells. This can result in extreme pressure fluctuations within the systems with the lift unit adjusting to optimize production from the well. Multiply this action for numerous wells and the flow characteristics needed to propel an ILI tool become unmanageable or nonexistent.

The only acceptable assessment methods PHMSA is proposing, without prior notification, is ILI with the ability to detect "... corrosion and deformation anomalies, including dents, cracks, gouges, and grooves,..." As PHMSA is aware, single tools capable of detecting all of these different anomalies are very limited in availability and are possible by "training" the various components together. The ability to do this with small diameter, such as the gathering lines targeted (6.625" – 8.625") is not available. Even if it were, the tool length would likely not be able to negotiate most gathering lines. Thus, multiple tools would have to be run, whether a particular threat exists or not, to satisfy the rule as proposed.

PHMSA only included costs associated with one run per assessment versus the two or three different ILI tools that will be required to assess for all of the threats PHMSA has included in the proposal. Under the current integrity management assessments required, the operator is directed to explain the assessment method selected and the risk factors considered. As proposed, there is no consideration of the actual threat(s) for a particular pipeline. Thus, there is no permissible deviation from running multiple ILI tools. For this reason, GPA feels the costs to assess an isolated 1 mile section of regulated gathering could cost significantly more than conducting a hydro-static test ("Hydro Test") if three mobilization fees are incurred for the ILI process.

PHMSA is proposing to require notification for any assessment that does not use ILI. We are confident that it will take member companies more than the one hour PHMSA has allocated to develop the justification necessary to demonstrate the impracticability and formulate the engineering analysis to exhibit a substantially equivalent understanding of the condition of the pipeline will be provided using the alternative method. The notification will likely extend to a substantial amount of the (+/-) 4000 miles of gathering, not the ten requests PHMSA has projected it will receive.

Within the RIA, PHMSA included the following discussion and sought comment.

Neither the estimate for ILI testing nor the estimate for the pressure testing includes the loss of throughput during the 6 to 10 days that the pipeline is shut down for testing. The lost revenue during this time can be a significant cost to the operator, but the loss to the operator performing the test is a gain to other operators who may move the throughput

⁴ Pipeline Safety: Protecting Unusually Sensitive Areas From Rural Onshore Hazardous Liquid Gathering Lines and Low-Stress Lines, FR June 3, 2008 (Volume 73, Number 107)

instead. From a cost-benefit perspective, there is no net social loss from the loss of throughput for an individual operator, provided that the liquid will be rerouted through other pipeline. If, however, the temporary closure of a pipeline for pressure testing results in a bottleneck that significantly delays the delivery of HL product to end users, then the cost delays caused by lost throughput could be a significant cost associated with pressure testing. PHMSA seeks comment on the cost of pressure testing in general and the cost of lost throughput specifically.

PHMSA misstates the impact to gathering operators by comparing gathering pipeline operations to the intrastate and interstate pipeline grids. Gathering pipelines are designed hydraulically to move production from specific formations. A typical gathering system is dedicated to an individual operator and is not always connected to other gathering pipelines. Therefore, moving product on another operator's dedicated gathering system is not a readily available option without months of commercial planning and negotiating, possibly requiring installation of additional pipeline, all of which is cost prohibitive. If a commercial solution is not available, shutting in a gathering line would negatively result in production shut-ins, possibly damaging the formation and forever lost production.

All gathering throughput will either cease or incur trucking costs as there is seldom an alternate pipeline route available. The cost for smaller diameter is not half as PHMSA has assumed. Much of the cost of the actual test is labor and equipment, not purchasing water. As API-AOPL noted in their response to the ANPRM, operators of crude oil gathering systems continually assess the economic viability of their gathering lines. Imposing further regulatory compliance activities with little or no realized benefit may well result in transportation turned over to trucking organizations. The crude oil is thus moved from a safe and unobtrusive mode of transportation located underground (pipeline) to one with many more hazards located on public highways and roads and contribute to increased greenhouse gas emissions from commercial trucks.

In the proposal to collect data on unregulated gathering lines, PHMSA stated the objective is seeking to obtain data to make informed decisions regarding rulemaking. A review of PHMSA accident data⁵ from 2010 to current reveal that 87 of the 2256 reported accidents occurred on gathering lines. This equates to 3.8% of the accidents reported. Of these, 45 occurred on gathering lines reported to have MOP's established at a pressure $\leq 20\%$ SMYS, which implies they are in a non-rural location and are likely subject to the Integrity Management Programs prescribed in § 195.452. Thus, it would appear that the proposal is targeted at pipelines which, at most, have caused 1.9% of the reportable accidents in the last five years.

Therefore, GPA urges PHMSA to remove this provision from the final rule, implement the data collection component, and use the data collected to make fact-based, risk-based decisions in the future.

Leak Detection on Gathering

⁵ <http://www.phmsa.dot.gov/pipeline/library/data-stats/flagged-data-files>

PHMSA is proposing to require the installation and maintenance of leak detection systems on all liquids pipelines. In its proposal, PHMSA has stated *“The use of such systems will help to mitigate the effects of hazardous liquid pipeline failures that occur outside of HCAs.”* In Section 5 of the ACT, congress directed PHMSA to study and report on leak detection and within the study include, *“...an analysis of the technical limitations and the practicability, safety benefits, and adverse consequence of establishing additional standards.”* Kiefner and Associates, Inc. completed the required study on leak detection systems used by all types of pipeline transportation. That study, titled “Leak Detection Study”⁶, evaluated leak detection systems on gas transmission, gas distribution, and hazardous liquids systems.

The Kiefner study covered 30 months from 2010 – 2012. Within the study period, liquid transmission pipelines experienced 197 accidents with five fires with two exploding and one of those resulting in a public fatality. The largest volume spilled was 843,444 gallons with the second largest at 556,122 gallons and the smallest 0.42 gallons.

During the same time period there were 22 reportable releases from gathering lines. The largest release from a gathering line was 8400 gallons. The smallest was 10 gallons. None of the 22 resulted in ignition or explosion. For the releases associated with the gathering lines, SCADA was reported as functional in 5 of the 22 reported incidents. Of the five accidents where SCADA was functioning, only one (1) of the incident reports indicated that SCADA assisted in the detection of the incident. Thus, SCADA was effective in aiding detection only 20% of the incidents reported.

The North Dakota legislature passed House Bill No. 1358, which was signed by Governor Dalrymple in April 2015. One provision of the bill required the North Dakota Industrial Commission (NDIC) to contract with the Energy and Environmental Research Center (EERC) at the University of North Dakota to *“...determine the feasibility and cost effectiveness of requiring leak detection and monitoring technology on new and existing pipeline systems.”* That study, “Liquids Gathering Pipelines: A Comprehensive Analysis”⁷, was delivered to the NDIC and the Energy Development and Transmission Committee on December 1, 2015. The leak detection portion of the research was focused on leak detection capabilities and limitations for crude and produced water gathering systems exclusively. The study generated several “key findings” that are related to PHMSA’s proposal. The following quotes from within the body of the report directly illustrate why PHMSA’s proposal is not appropriate for gathering lines at this time:

- *It should be emphasized that gathering lines present unique challenges to leak detection technologies. As a result, some care must be taken when extrapolating transmission line experience to gathering lines.*

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http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_4A77C7A89CAA18E285898295888E3DB9C5924400/filename/Leak%20Detection%20Study.pdf

⁷ <http://undeerc.org/Bakken/Pipeline-Study.aspx>

- *Gathering line systems are constantly transitioning in flow, pressure, and line-packing. Unlike transmission pipelines with very few branches, gathering systems have tens to hundreds of pipeline connections. These and other differences between transmission pipelines and gathering lines create greater challenges for designing, installing, and operating internal leak detection on gathering lines than transmission pipelines.*
- *Company decisions regarding implementing new pipeline monitoring and leak detection technology rely upon, among other things, analysis of the cost and benefit. There is a need for objective data on the performance of different leak detection technologies under real-world conditions.*
- *The better defined the operational conditions are, the more sensitive the leak detection method that can be applied. Low-pressure operation is common, and multiple flow inlets and very few outlets lead to significant flow variation as pumps cycle on and off or wells begin or cease production. The very nature of oil production leads to fluctuations that are not easily reduced or eliminated.*
- *At this time, no technology has demonstrated undisputed reliability in detecting spills on interstate pipelines, much less on more problematic gathering lines.*

Consistent with the recommendations for assessments on gathering, GPA urges PHMSA to remove this provision from the final rule, implement the data collection component, and use the data collected to make fact-based, risk-based decisions in the future.

C. Gravity lines

Extension of the Reporting Requirements

In response to the ANPRM, API-AOPL provided PHMSA with comments identifying the fact that 3 of their member companies operate a total of 17 miles of gravity lines. As PHMSA points out, gravity lines may also exist in tank farms. PHMSA has estimated that, at most, five hazardous liquid pipeline operators will be affected. At least three GPA members have responded expressing concern with the ability to gather all of the data required to comply with the data collection effort as proposed without extensive resource commitment. All would involve piping at tank farms.

The majority of GPA responding members support the data collection efforts with essentially the same comments and concerns expressed above for gathering lines. We recommend an abbreviated form as described above for this purpose as well.

D. Leak Detection (non-gathering)

As discussed above for gathering lines, PHMSA has proposed a requirement to require leak detection and computational pipeline monitoring (“CPM”) for those segments outside of (HCA’s). Unlike applying the proposed requirements to gathering systems, GPA generally supports the proposal for remaining pipelines.

In the proposed §195.134(b), PHMSA has pointed to the requirements in § 195.444. In the proposed §195.134(c), PHMSA has explicitly cited Section 4.2 of API 1130 for new or replaced systems or components. It would provide further clarity if PHMSA would provide the specific citations in API 1130 it expects operators to follow, such as Section 6.5 for CPM training.

PHMSA did not include any discussions or proposal for expected compliance timeframes or retroactive application. The current requirements in §195.444 are applicable to those CPM systems in place. The proposal appears to require installation of leak detection indiscriminate of the time the pipeline was installed. No assumed costs have been provided for those systems which do not already have something in place. Compliance timing for the proposed training component are absent also. Implementation timeframes should be longer for systems that have no leak detection currently in place versus those which need minor modifications and those which fall somewhere between. Likewise, there may be programs in place as sub-components of Control Room Management training which satisfy the requirements, but an evaluation may still be necessary for validation purposes. And there may be impacted operators which do not currently have control rooms or the CPM functions outside of the control rooms and may require development and implementation from the ground up. PHMSA has not included any estimates of expected costs for the training component of this proposal.

GPA urges PHMSA to establish a seven (7) year installation and implementation timeframe. This should provide time to conduct system evaluation for use in leak detection system design, procurement, installation, testing, and training. The GPA urges PHMSA to provide relief for short sections less than one (1) mile in length and those that are located within facilities where they pose no risk to the public. Dedicating resources without likely benefit provides value to no one. It would also provide continued consistency with the exceptions provided in §195.120 and the recommendations GPA is submitting for the ILI assessments proposal.

E. Post Disaster Investigations

GPA supports what it believes to be the spirit of the proposal as published by PHMSA. However, PHMSA’s expectations for operator actions under the “weather related” inspection are not clear. To begin with, a “weather related” event can have dramatically different effects based on the type of event. Is this expectation to use NOAA 10 year, 50 year, or 100 year data for flood conditions? Areas, such as Oklahoma, have experienced hundreds of earthquakes over the last two or three years. Yet, most are in the 2.0 Richter range. Hurricanes may range from Category 1 to Category 5 and as PHMSA is aware, can have dramatically different consequences. PHMSA must either define exactly which events require response and inspection or establish performance expectations without partially defining the criteria.

PHMSA should define cessation as “the point in time when the operator determines no further threats to personnel safety or equipment exists” as the time when evaluation activities may proceed.

PHMSA has proposed the inspection occur within seventy-two (72) hours after cessation of the event. Does this mean that PHMSA expects the inspection to be started, in-progress, or completed? In large scale events, such as Hurricane Rita and flooding of the San Jacinto River, there may not be resources available, such as generators or ILI tools for all operators to accomplish the goals PHMSA is proposing.

As an alternative to creation of a completely new regulatory section, PHMSA could modify the section requiring Emergency Plans (§ 195.402(e)) to require an inspection following events to determine if an emergency situation has developed and, if so, the provisions in the operator’s emergency plan should be implemented. This would be a less ambiguous way to achieve the desired goal.

We propose PHMSA amend § 195.402(e) to read as follows;

(e) Emergencies. The manual required by paragraph (a) of this section must include procedures for the following to provide safety when an emergency condition occurs;

(1) Receiving, identifying, and classifying notices of events which need immediate response by the operator or notice to fire, police, or other appropriate public officials and communicating this information to appropriate operator personnel for corrective action.

(i) The notices of events must include extreme weather events which may impair the serviceability of the operator’s pipelines in the area and the operator must inspect all potentially affected pipeline facilities as soon as the operator determines no further threats to personnel safety or equipment exists.

(ii) An operator must take appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required under paragraph (i) of this section.

F. Non-Integrity Management Segment Provisions (not gathering)

Assessments and Notifications

PHMSA is proposing to require assessments for pipeline segments in non-HCAs. Specifically, the proposed § 195.416 would require operators to assess non-HCA (non-IM) pipeline segments with an ILI tool at least once every 10 years. PHMSA has further stated that other assessment methods could be used if an operator provides the Office of Pipeline Safety (OPS) with prior written notice that a pipeline is not capable of accommodating an ILI tool. The written notice provided to PHMSA must include a technical demonstration of why the pipeline is not capable of accommodating an ILI tool and what alternative technology the operator

proposes to use. The operator must also detail how the alternative technology would provide a substantially equivalent understanding of the pipeline's condition in light of the threats that could affect its safe operation. Such alternative technologies would include Hydro Testing or appropriate forms of direct assessment.

GPA questions why PHMSA has not taken the more reasonable approach as it is proposing in the modifications to § 195.452(c)(1)(i)? PHMSA and its state partners would still be able to evaluate the reasons an ILI was not used, but without the burden, on both regulators and industry and the delay created by the notification process.

In the RIA, PHMSA has assumed a cost of \$5150 per mile to assess using ILI, including costs for pipeline cleaning, labor, and contractor selection and oversight. While GPA could not obtain 2015 dollars within the comment period window, we believe this is underestimated.

In the RIA, PHMSA assumed that new construction pipelines would not incur any assessment costs in the first ten years since they would be Hydro Tested post construction. However, as written, PHMSA is proposing to require prior notification to use any assessment method other than ILI. Through literal interpretation of the proposal, an operator would submit prior notice during the construction of a pipeline that it plans to use the post construction Hydro Test as a "qualifying assessment" as well. Is this the process PHMSA envisions for an operator to be compliant without conducting duplicative tests? Currently, we see no recognition of this test as sufficing for an assessment without notification within the proposed rule. GPA would like PHMSA to provide clarification on this issue.

If this is not the case and PHMSA recognizes a post construction Hydro Test as a valid assessment method for revealing harmful defects, then the same recognition should be afforded those used as regular assessments without a prior notification.

PHMSA did not include any expectations for implementation timeframes in the proposal. Is there a percentage per time period anticipated, i.e. 50% each five years or is PHMSA willing to provide operators scheduling flexibility to weave it into other compliance activities? For example, if an operator is running an ILI on Pipeline A as a 5 year reassessment for IM purposes, they may have the ability to conduct an assessment on Pipeline B in the same general geographic area and possibly minimizing or eliminate some mobilization costs and maximize use of resources.

GPA requests PHMSA provide exceptions for short lines, e.g. less than 1 mile in length, that are contained within the operators facilities and pose no risk to the public. This would keep it consistent with the exceptions contained, currently and in the proposed modified §195.120(b).

GPA would also like to know if PHMSA considers deferring assessments on Out-of-Service Idle (product evacuated, nitrogen blanketed) lines until preparation for return to service acceptable under this proposal? Under these conditions, there is no risk from a release. This would be consistent with policy established during implementation of the Integrity Management Program.

Data Analysis

PHMSA is proposing to include performance language requiring persons performing the data analysis of non-IM assessments to be “qualified by knowledge, training, and experience.” API-AOPL and many other commenters responding to questions posed in the ANPRM supported the incorporation by reference of American Society of Nondestructive Testing (ASNT) ILI PQ to satisfy the need to assure quality data analysis. In this preamble, PHMSA has stated *“PHMSA is proposing by a separate rulemaking via incorporation by reference available industry consensus standards for performing assessments of pipelines using ILI tools, internal corrosion direct assessment, and stress corrosion cracking direct assessment.”*

We encourage PHMSA to include ASNT ILI PQ as part of that rulemaking while deferring action on the current proposal. Operators typically do not have the expertise to judge vendors on their proprietary technologies.

Non-IM Remediation

PHMSA is proposing to establish essentially the same repair criteria as for those segments which could affect a HCA without identifying why it is believed this is a necessary step. Has PHMSA documented through its enforcement program that the current requirements in §195.401(b)(1) are unenforceable as written?

At a minimum, PHMSA should revise the “18 month” timeframe to read two years to allow for scheduling around unfavorable weather conditions which can be detrimental to the repair process and to enable them to be included in budget processes.

G. Integrity Management Assessments

Required Use of ILI

Changes proposed for §195.452(c)(1)(i) to require use of ILI unless it is impracticable seems to be a reasonable approach and encourages use of ILI, but does not penalize the operator by requiring notifications. It allows for the continued use of other methods which may be more appropriate for threats such as Low Frequency Electric Resistance Welded pipe.

As stated above, we urge PHMSA to adopt the same approach for non-gathering, non-IM assessments proposed in §195.416.

Information Analysis

GPA does not believe PHMSA’s proposal as written (§ 195.452(g)), is necessary. It is duplicative of much of the material contained in Appendix C, PHMSA’s Enforcement Guidance documents, and API RP 1160. If PHMSA has experienced failure of operators to consider these factors, it would appear this is an enforcement issue not a reason to create more regulation. The expectations have been clearly communicated throughout implementation of the integrity management programs.

Modifications to Accommodate ILI

GPA believes it would be reasonable to implement this element for pipelines in HCA's. For the reasons discussed in the "Performing Assessments on Gathering" section above, applying this requirement to gathering and short lines will likely result in money spent for retrofitting, but resulting in pipelines which will still not be "piggable" because of flow characteristics. Thus, spending the required capital without obtaining the desired results of being "piggable" could render many gathering systems uneconomical to continue operating moving them back to reliance on trucking.

GPA appreciates the opportunity to comment on the notice and request for comments regarding "*Pipeline Safety: Safety of Hazardous Liquid Pipelines*" published by PHMSA in the October 13, 2015 Federal Register. GPA has provided comments and recommendations that will create a practical path forward to meet the continued need to achieve US energy independence while ensuring the infrastructure used to transport it continues to do so in a safe, economical manner. Please contact me at (202)279-1664 or mhite@gpaglobal.org if GPA can be of assistance.

Sincerely,

Matthew Hite
Vice President of Government Affairs
Gas Processors Association