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Topic	Subtopic	Sub-sub Topic	Comment
A. Records			Several citizen groups including Pipeline Safety Coalition and Pipeline Safety Trust supported the increased emphasis on recordkeeping requirements, stating that the requirements are a proactive response to National Transportation Safety Board (NTSB) recommendations and are common sense business best practices.
A. Records			Several commenters opposed the proposed provisions in § 192.13(e) that provide general recordkeeping requirements for Part 192. Commenters asserted that these provisions apply significant new recordkeeping requirements on operators by requiring that operators document every aspect of Part § 192 to a higher and impractical standard. Commenters also stated that the proposed requirements in § 192.13(e) appear to be retroactive, and stated that it would be inappropriate to require operators to document compliance in cases where there have not been requirements to document or retain records in the past. INGAA asserted that the proposed rulemaking does not comply with the Paperwork Reduction Act (PRA), because PHMSA's estimate of the information collection burden did not include the costs of these additional recordkeeping requirements for transmission pipeline operators.
A. Records			Many commenters opposed the proposed application of the term "reliable, traceable, verifiable, and complete" in Part 192 beyond the requirements for MAOP records. Commenters opposed the use of this term in § 192.13(e)(2), stating that it would apply a new standard of documentation to Part § 192. Additionally, many commenters stated that "reliable" should be eliminated from the phrase "reliable, traceable, verifiable, and complete" and that the remainder of the phrase should be defined, providing suggested definitions for the phrase. Citing a PHMSA 2012 Advisory Bulletin in which PHMSA stated that verifiable records are those "in which information is confirmed by other complementary, but separate, documentation", Interstate Natural Gas Association of America (INGAA) requested that PHMSA acknowledge that a stand-alone record will suffice and a complementary record is only necessary for cases in which the operator is missing an element of traceable and complete. INGAA also provided examples of records that they believed to be acceptable, and requested that PHMSA includes these examples in the final preamble.

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A. Records			Several commenters opposed the proposed Appendix A that summarizes the records requirements for Part § 192, and requested that it be eliminated. Providing several examples, these commenters stated that Appendix A goes beyond summarizing existing records requirements and introduces several new recordkeeping requirements and retention times. Commenters also asserted that Appendix A should not be retroactive.
A. Records			Some commenters supported the inclusion of Appendix A, saying that it is a much needed clarification of record requirements and retention. Noting that the title of Appendix A suggests that it is specific to transmission lines but that it does include some record retention intervals for distribution lines, National Association of Pipeline Safety Representatives (NAPSR) recommended that Appendix A be expanded to include records and retention intervals for all types of pipelines. Other commenters requested that PHMSA clarify that the proposed changes to Appendix A, including new record keeping requirements, apply only to transmission lines.
A. Records			Several commenters stated that recordkeeping requirements in Part 192 should not apply retroactively. Commenters asserted that 49 US Code § 60104(b) prohibits PHMSA from applying new safety standards pertaining to design, installation, construction, initial inspection and initial testing to pipeline facilities already existing when the standard is adopted, and that PHMSA does not have the authority to apply these requirements retroactively. Several commenters provided input on the retroactive nature of the IVP requirements, and these comments are discussed in Section C.iii (Adequate Material and Documentation) of this document. Additionally, commenters requested that PHMSA confirm that §§ 192.13, 192.67, 192.127, and 192.205 would not apply to existing pipelines and that §§ 192.227 and 192.285 would not apply to completed pipeline projects.
A. Records			Some commenters also opposed the proposed recordkeeping requirements for pipeline components in § 192.205. Commenters including Dominion East Ohio stated that PHMSA should exclude pipeline components less than 2" in diameter, as these small components are often purchased in bulk with pressure ratings and manufacturing specifications only printed on the component or box. They further

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			stated that in doing this, PHMSA would be consistent with the Material Verification requirements in proposed § 192.607(d)(4)(ii). Another commenter stated that these requirements should be eliminated because they are duplicative of the current requirements for establishing and documenting MAOP in § 192.619(a)(1).
A. Records			Some commenters also opposed the proposed recordkeeping requirements regarding qualifications of welders and welding operators and qualifying persons to make joints in §§ 192.227 and 192.285. These commenters stated that requiring certain records for transmission lines be retained for the life of the pipeline is not needed. Additionally, commenters stated that these requirements are not relevant to the establishment of MAOP.
A. Records			Several commenters also requested that PHMSA clarify that many of the records requirements, including the proposed requirements in §§ 192.13(e), 192.67 and 192.127 and 192.205 apply only to transmission lines.
B. Legal			Several commenters asserted that the proposed provisions go beyond PHMSA's statutory authority provided by the Pipeline Safety Act. Many trade associations and pipeline industry entities stated that PHMSA exceeded congressional mandates in the proposed provisions that address retroactive record-keeping requirements, retroactive material verification requirements, and gathering line regulations. These comments are discussed in sections A, C, and E of this document, respectively.
B. Legal			Commenters asserted that Congress identified specific factors in the Pipeline Safety Act (practicable, reasonable, and appropriate) that PMSA is required to take into account, and that the proposed rule did not adequately address these factors. For example, AGA expressed concerns that PHMSA proposed to adopt NTSB recommendations without independently justifying those provisions based on the specific factors required by Congress.
B. Legal			AGA and INGAA also stated that PHMSA did not adequately consider the impact that the Natural Gas Act would have on implementation of the proposed rule. Noting that pipelines are required to obtain permission from FERC before removing pipelines from service or replacing pipelines, these commenters stated

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			that obtaining permissions could hinder operators from quickly performing required tests and repairs and constrain an operator's ability to permanently remove pipelines from service. INGAA and AGA also stated that PHMSA did not consult with FERC and state regulators about implementation timelines, which PHMSA is required to do according to 49 U.S.C. § 60139(d)(3) because gas service would be affected by the proposed rule.
B. Legal			Several commenters expressed concern that PHMSA's cost-benefit analysis does not meet the requirements established by the PSA and the Administrative Procedures Act. Trade associations stated that the PRIA does not fulfill PHMSA's statutory obligations because it omits relevant costs, relies on incorrect assumptions and contains multiple inconsistencies. INGAA asserted that the PRIA does not comply with the APA because the finding in the PRIA that the proposed benefits outweigh the costs is contingent on an underestimation of the costs of the proposed rule. INGAA also noted that flawed cost-benefit analysis can be grounds for courts to reject agency rulemakings.
C. IVP	Adequate Material and Documentation		Several citizens groups including Pipeline Safety Trust, Pipeline Safety Coalition, NAPSR, Coalition to Reroute Nexus, Earthworks, and PROTEC supported the proposed provisions covering adequate material documentation and records. Trade associations and industry pipeline entities generally opposed the proposed requirements, with their comments spanning three topics discussed below: (1) retroactive implementation; (2) detailed record requirements; and (3) implementation timeline.
C. IVP	Adequate Material and Documentation		Many commenters expressed concern that the material documentation requirements were potentially retroactive. API and AGA asserted that operators must document and verify material properties of existing pipelines beyond what was required by the regulations that were in place at the time the pipelines were put into service. As discussed in Section B of this document, these commenters stated that this retroactive requirement extends beyond the congressional authority provided to PHMSA. Several commenters including AGL Resources, Dominion East Ohio, and New Jersey Natural Gas expressed concern with the proposed provisions for verifying specific physical characteristics of pipelines,

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			fitting, valves, flanges, and components for its existing transmission pipelines. These stakeholders stated that it may be impossible to achieve "reliable, traceable, verifiable, and complete" records on a retroactive basis for existing pipelines. Some commenters including AGA stated that in cases of a test record of at least 1.25 × MAOP pressure test, the MAOP should be considered confirmed and there should be no need to further document material properties to verify the MAOP.
C. IVP	Adequate Material and Documentation		Several commenters suggested that the data required by § 192.607 can be obtained only through destructive pipe testing. These commenters asserted that the proposed requirements would lead to unnecessary outages, increased methane emissions, and increased personnel safety risks due to unnecessary construction activities. Black Hills Energy stated that its system is constructed of mainly smaller diameter transmission pipelines, and that the proposed provisions would force them to take lines out of service to perform costly cutouts. API asserted that the expense and risk required for the excavations required to comply with the proposed provisions outweigh the value of obtaining material and documentation.
C. IVP	Adequate Material and Documentation		Several commenters stated that some of the data that PHMSA proposed operators verify is unnecessary for MAOP verification or other operational reasons. For example, INGAA stated that several of the data elements that would need to be verified pursuant to § 192.607 are unnecessary for integrity-related activities. ONE Gas disagreed with the requirement to determine the chemical composition of transmission pipe segments installed prior to the effective date of the final rule in §§ 192.67, 192.205 and 192.607, suggesting that this information has not been previously required. They further stated that this data is largely unavailable despite otherwise sufficient documentation existing that satisfies existing design considerations in Subpart C. PG&E recommended that PHMSA recognize that chemical composition and manufacturing specification provide limited information that can be used to evaluate the safety of an existing pipeline system. Piedmont Natural Gas stated that any requirement to retroactively obtain ultimate tensile strength and chemical composition is unnecessarily burdensome

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			and detracts from the ultimate goal of pipeline safety by diverting valuable resources away from other risk-reduction efforts.
C. IVP	Adequate Material and Documentation		API suggested that rather than requiring operators to gather documentation on material properties that may only be of marginal value for assessing pipeline safety, PHMSA should require a combination of hydrostatic pressure testing and ILI. API stated that as opposed to the proposed rule's focus on precise documentation of materials, this would appropriately shift the emphasis to confirming MAOP and away from material documentation. API's proposal to require hydrostatic pressure testing in combination with ILI is further discussed in Section C.iv.2 of this document.
C. IVP	Adequate Material and Documentation		Commenters also expressed concern about PHMSA's proposed new references to § 192.607 throughout Part 192, which could be interpreted as a new material verification requirement applicable not only to a subset of transmission pipelines, but also to distribution pipelines (see also comments summary in Section A of this document). Commenters stated that PHMSA did not provide justification within the proposed rule to apply material verification requirements on distribution systems, which would impose a significant impact on distribution systems. They requested that PHMSA expressly exclude distribution pipelines from the proposed material verification requirement.
C. IVP	Applicability to High-Risk Locations (HCAs, Class 3 & 4 Locations, MCAs)		Several commenters opposed the proposed provisions outlining the applicability of the IVP requirements to high-risk locations. American Petroleum Institute (API) stated that the current proposal would be duplicative regulation, stating that there are existing rules that require operators to perform certain testing and assessments outside of HCAs. GPA Midstream Association (GPA) and American Gas Association (AGA) stated that while they support the congressional mandate to conduct testing to confirm the material strength of previously untested gas transmission pipelines in HCAs that operate at a pressure above 30% SMYS, they oppose the proposed provisions which extend to additional pipeline segments. INGAA and Washington Gas supported the applicability of MAOP reconfirmation in MCAs for pipelines operating at greater than 30% of SMYS, but disagreed with the proposed provisions that

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			included MCA pipelines operating at less than 30% SMYS.
C. IVP	Applicability to High-Risk Locations (HCAs, Class 3 & 4 Locations, MCAs)		Other commenters recommended that the proposed provisions be strengthened. For example, Pipeline Safety Trust stated that PHMSA should fully implement the recommendations made by the NTSB and eliminate the grandfather clause, given that the proposed rule would not include the following groups of pipelines: (1) pipelines in non-HCA areas within classes 1 and 2; and (2) pipeline segments for with there is inadequate record of a hydrostatic pressure test in areas newly designated as MCA that are capable of being assessed by an in-line tool. The California Public Utilities Commission (CPUC) and Michigan Public Service Commission (MPSC) suggested that an element of risk prioritization should be added to the operator plans required in proposed §192.624 (b). Similarly, TPA stated that greater priority should be given to the pipelines subject to the congressional mandate, and that these pipelines should be the first set of pipelines subjected to verification efforts.
C. IVP	Fracture Mechanics		Most industry stakeholders were opposed to proposed fracture mechanics requirements. AGA, New Mexico Gas Co. and TPA suggested that fracture mechanics have a limited place in preventing pipeline failures or predicting them accurately, and are appropriate for only unique applications. AGA stated that the rule should not prescriptively require fracture mechanics calculations to be performed for a broad range of applications but should be narrowed to include only transmission pipelines operating at a hoop stress greater than 30% SMYS, given that pipelines that operate below 30% SMYS have a strong tendency to leak rather than rupture.
C. IVP	Fracture Mechanics		Commenters also stated that requiring fracture mechanics as any part of the MAOP verification process was overly burdensome and unclear. Specifically, API stated that some of the requirements listed under § 192.624(d) were overly conservative and burdensome for most situations where this technique would be used. Energy Transfer Partners suggested that the proposed language for fracture mechanics is misplaced in MAOP verification and should be moved to proposed § 192.710 since this text more closely resembles an "assessment."
C. IVP	Perform		Several stakeholders including AGA, Louisville Gas & Electric, New Mexico

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	Assessments to Establish MAOP (6 Methods)		Gas Company, National Grid, NW Natural, PECO Energy, TECO Pipeline Gas and NYSEG proposed an alternative method for MAOP verification in which operators would execute two separate sets of actions which they stated could be performed simultaneously or separately. First, operators would either pressure test or utilize an alternative technology that is determined to be of equal effectiveness on high-risk gas transmission pipelines. Operators would test pipes in three tiers depending on the pipe's SMYS and Class designation. Second, operators would use an in-line inspection tool on all gas transmission pipelines regardless of class location that are capable of accommodating in-line inspection tools. The ILI tool used would be qualified to find defects that would fail a Subpart J pressure test. These commenters stated that this alternative methodology was necessary because the proposed provisions would create operational inefficiencies that would likely result in excessive cost and limited public benefit. In addition to providing this alternative proposal, many of these commenters also provided comments on the proposed provisions.
C. IVP	Perform Assessments to Establish MAOP (6 Methods)		Commenters expressed concern that the proposed provisions in § 192.619 would expand the applicability of requirements to distribution lines. AGA requested that PHMSA strike language from § 192.619(a)(4) that references § 192.607 (material verification), because it has the potential to inadvertently expand applicability of § 192.607 to include all pipelines, both transmission and distribution. Multiple commenters expressed concerns that the proposed provisions in § 192.619(f) would impose extensive new record keeping requirements applicable to operators of distribution pipelines, both existing and new, including retroactive record keeping requirements. Commenters requested that PHMSA clarify that the new record requirements in § 192.619 (f) are applicable only to gas transmission pipelines.
C. IVP	Perform Assessments to Establish MAOP (6 Methods)	Method 1: Pressure Test	Several commenters opposed the proposed provisions requiring a spike test to be conducted as part of the pressure test. These comments are summarized in Section C under "Spike test"of this document. Additionally, API asserted that MAOP can be best established through a combination of pressure testing and ILI. API specifically recommended modifications to the proposed pressure test

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			requirements which include using hydrostatic pressure testing to determine the in-place yield strength of a segment of pipeline, and conducting this in conjunction with a "spike test" held for a few minutes, followed by a Subpart J test approximately 10% below the spike level. API further stated that using ILI tools in conjunction with this method would further substantiate the results.
C. IVP	Perform Assessments to Establish MAOP (6 Methods)	Method 1: Pressure Test	AGA stated that while they believe that pressure testing is a straightforward and well-established method, the proposed Method 1 requirements are unnecessarily complex. AGA further stated that Subpart J provides different requirements and specifications for pressure tests based on the type of pipe being tested, and that Method 1 should refer to subpart J rather than to § 192.505(c) which requires unnecessarily stringent requirements. PG&E supported the proposed provisions in § 192.624(c) and committed to pressure testing all pipes.
C. IVP	Perform Assessments to Establish MAOP (6 Methods)	Method 1: Pressure Test	INGAA stated that given that the basic strength properties of steel pipe do not change over time, PHMSA should not limit allowable tests to only those conducted after July 1, 1965, as was proposed in § 192.619(a)(2)(ii). They emphasized that recognizing the validity of earlier tests would not necessarily mean that no further pressure tests would be conducted, as periodic testing may be required to ensure the continued integrity of the segment under the operator's integrity management program.
C. IVP	Perform Assessments to Establish MAOP (6 Methods)	Method 1: Pressure Test	Regarding the proposed new definition of "Legacy Pipe" and "Legacy Construction," AGA and Xcel Energy commented that as proposed, it could be interpreted to apply to distribution pipelines. Commenters requested that PHMSA explicitly exclude distribution piping from these definitions.
C. IVP	Perform Assessments to Establish MAOP (6 Methods)	Method 2: Pressure Reduction.	AGA commented that the 18-month time frame listed in § 192.624(c)(2) is a much too narrow time frame for consideration, and that § 192.624(c)(2) should be rewritten to clarify that the pressure reduction should be taken from either (1) the immediate past 18 months or (2) 5-years from the time the last pressure reduction was contemplated, stating that tying the baseline pressure to the effective date of the rule is arbitrary. TPA stated that § 192.624(c)(2) unfairly penalizes operators in situations where the operator has prepared for future needs

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			and has not operated at MAOP for a period greater than 18 months. Enterprise Products recommended that PHMSA clarify the de-rating criteria used for pipes that use this method of establish MAOP. Piedmont expressed concern that this method does not account for the actual gap that can occur between MAOP and operating pressure.
C. IVP	Perform Assessments to Establish MAOP (6 Methods)	Method 3: Engineering Critical Assessment (ECA).	Several trade associations and pipeline industry entities stated that ILI is the best and most practical method due to its cost effectiveness and environmentally friendly nature, and that PHMSA should allow operators to use ILI to reconfirm MAOP. These commenters, however, stated that the requirements proposed for Method 3 are overly complicated and burdensome. These commenters stated that the final rule should be simplified so that this method will play a greater role in MAOP reconfirmation in lieu of the pressure test. For example, INGAA asserted that PHMSA should remove the requirements related to operations, maintenance, and integrity management, given that these methods do not belong in a MAOP reconfirmation provision and are covered elsewhere in Part § § 192. INGAA further proposed additional alternatives that operators should be permitted to use to obtain necessary data, and asserted that these alternatives would be less burdensome and equally effective. TransCanada and PECO Energy Co. stated that in order for this method to be used by industry, the detailed requirements listed in §192.624(c)(3) should be replaced with the use of standard ECA best practices.
C. IVP	Perform Assessments to Establish MAOP (6 Methods)	Method 3: Engineering Critical Assessment (ECA).	Pipeline Safety Trust stated that there are certain cases in which Method 3 should not be allowed as an alternative to pressure testing. Citing a white paper prepared by Accufacts, Inc. on ECA, Pipeline Safety Trust recommended that PHMSA prohibit the use Method 3 for determining the strength of a pipeline segment in cases where there are girth weld crack threats, significant stress corrosion cracking threats, or dents with stress concentrator threats.
C. IVP	Perform Assessments to Establish MAOP (6	Method 4: Pipe Replacement.	Commenters including Mid-American Energy Company and Paiute Pipeline stated their support for this method.

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	Methods)		
C. IVP	Perform Assessments to Establish MAOP (6 Methods)	Method 5: Pressure Reduction for Small, Low Pressure Pipelines.	AGA stated that PHMSA did not provide enough justification for imposing the pressure reduction requirements listed in Method 5, asserting that this method should require either a 10 percent pressure reduction or the implementation of additional preventative actions that are feasible and practical, but not both. TPA stated that similar to Method 2, the 18-month criterion penalizes operators who may have operated pipelines at lower capacities to anticipate future needs. Furthermore, TPA urged PHMSA to limit the requirements for MAOP verification under Method 5 to the reduction in MAOP, stating that these pipelines are generally considered low stress pipelines and that their risk of rupture is very low. Similarly, API stated that the proposed requirements for odorization and frequent instrumented leak surveys are impractical.
C. IVP	Perform Assessments to Establish MAOP (6 Methods)	Method 6: Alternative Technology.	For the Method 6 Alternative Technologies, several stakeholders opposed the timeframes, case by case approval process, and procedural barriers PHMSA proposed for utilizing this method. Several commenters including Cheniere Energy, Delmarva Power & Light, and INGAA suggested that the procedural hurdles required by the proposed provisions would make this option nearly inaccessible to operators. They further stated that this method resembles the special permit process which they asserted has become burdensome for pipeline operators. Piedmont stated that it does not believe that the role of PHMSA includes determining the appropriate technologies to be used to establish MAOP. Piedmont further stated that currently under subpart O, operators are required to obtain approval from PHMSA to use alternative technologies for integrity assessment, and that operators have waited more than 180 days for PHMSA to respond to the request. Piedmont stated that this uncertainty cannot be reconciled with the planning and business considerations that an operator must consider when evaluating how to invest in technology and which methods to use for establishing MAOP. Pipeline Safety Trust stated that the approval process should be similar to the process used for special permits and that before these methods are approved by PHMSA, they should be subject to public review and comment under NEPA.

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C. IVP	Screening Segments for Areas of Concern		Some citizen groups including Pipeline Safety Trust expressed concern that the proposed changes did not go far enough and suggested that PHMSA should fully implement the recommendations set forth by the NTSB. Northeast Gas Association (NGA) stated that PHMSA should retain the grandfather clause, as it prevents existing, historically safe and maintained pipelines from being subjected to unwarranted requirements.
C. IVP	Screening Segments for Areas of Concern		Regarding the second category of pipelines that PHMSA proposed would be subject to the IVP requirements, for which operators do not have adequate documentation to support the pipeline MAOP, some commenters stated that they support the requirement to the extent that is consistent with the congressional mandate to reconfirm MAOP for pipelines within Class 3 and 4 locations and Class 1 and 2 HCAs for which records are insufficient. These commenters further stated that § 192.624(a)(2) should be revised to clarify that it applies only to those transmission pipelines in HCAs and Class 3 and 4 locations that were constructed and put into operation since the adoption of the federal pipeline safety regulations in 1970, stating that otherwise, § 192.624(a)(2) would apply to those pipelines put into service prior to the implementation of federal regulations, to which the requirement to maintain a pressure test record does not apply. Some commenters also stated that PHMSA should revise § 192.624(a) to make clear that operators that have used one of the proposed allowable methods for establishing MAOP in § 192.624(b) other than the pressure test are not required to have a pressure test record to comply with the record requirements in this section. Washington Gas asserted that the requirements of § 192.624(a)(2) should apply to only pipeline segments in high-consequence areas and operating at a pressure of greater than 30% of specified minimum yield strength. Other commenters including Xcel Energy stated that the proposed provisions are not appropriate, asserting that operator discretion regarding what constitutes a reliable, traceable, verifiable, and complete record should be sufficient to determine the necessary documentation to support pressure testing and material properties for MAOP verification. In addition, AGA recommended the deletion of "reliable, traceable, verifiable and complete" from proposed provisions in

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			§192.624(a)(2). Similarly, other commenters including INGAA recommended omitting “reliable” from the phrase and provided a suggested definition for “traceable, verifiable, and complete.”
C. IVP	Screening Segments for Areas of Concern		Lastly, many commenters either disagreed or requested clarification regarding the requirement that MAOP must be re-established where an in-service incident occurred due to a manufacturing defect listed in § 192.624(a)(1). For example, INGAA stated that an operator can evaluate the defects more effectively through ongoing operations and maintenance rather than through MAOP reconfirmation, and that the defects PHMSA is concerned with are already addressed through integrity management. Similarly, Boardwalk Pipeline stated that pipelines that have experienced an in-service incident as a result of the listed defects in § 192.624(a)(1) should be subject to integrity management rather than MAOP re-confirmation. TransCanada and Texas Pipeline Association (TPA) recommended adding text to § 192.624(a)(l) that would remove a pipeline segment from the MAOP verification requirement if the operator has already taken action to address the cause of the reported incident. Additionally, one commenter suggested that this requirement should apply to only pipelines in HCAs.
C. IVP	Screening Segments for Areas of Concern		Some commenters including AGA and Con Ed requested additional time to comply with the proposed provisions to establish MAOP for the three types of pipeline segments listed in § 192.624(a). For example, they asserted that since their current records would not satisfy many of the new requirements, they would be required to replace many of their transmission mains in order to comply with the new requirements. Due to the urban density and scale of their service area, they stated that this replacement process would take longer than the 15-year schedule proposed in the rule. One commenter suggested that if this criteria remains in the rule, it should be limited to a more contemporary time frame such as a rolling 15-year window or incidents occurring since 2003. Pipeline Safety Trust, on the other hand, stated that the proposed timeframe of 15 years for operators to establish MAOP is too long for lines within HCAs. They further stated that 15 years is significantly too long to wait for industry to complete critical safety work, and urged PHMSA to adopt significantly shorter

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			timelines in the final rule. In addition, AGA asserted that the proposed MAOP provisions do not address how the completion plan and completion dates required by § 192.624 (b) would apply to pipelines that might experience a failure in the future and would then be subject to proposed §192.624(a)(1), or for pipelines that are not currently located in a MCA but may be in the future. Lastly, INGAA stated that Section 23 of the Pipeline Safety Act requires that PHMSA consult with the Chairman of FERC and state regulators before establishing timeframes for the testing of previously untested pipes, and that it is not evident that PHMSA has complied with this requirement.
C. IVP	Spike Test		Some commenters supported the concept of requiring the use of spike hydrostatic pressure test as part of the IVP process for establishing MAOP, but expressed concern over specific provisions. For example, AGA urged PHMSA to allow pneumatic pressure tests as well as hydrostatic pressure tests. In addition, AGA disagreed with the allotted test duration suggested by the proposed provisions. Other industry participants such as CenterPoint Energy and Dominion East Ohio stated that the proposed spike test target hold pressure of 30 minutes far exceeds the time needed to determine the mechanical integrity of the pipeline test segment and will cause pre-existing crack-like defects to grow in size. Alternatively, Dominion Transmission, Tallgrass Energy Partners, SoCalGas, and Paiute Pipelines stated that 100% SMYS, not 105% SMYS, would be sufficient to establish cracking threats. Enterprise Products stated that the requirements for the design of a spike test should be based on integrity science, such as fatigue life and reassessment interval, not an arbitrary level. Enterprise further stated that the utility of stressing a pipe beyond 100% of its yield strength is questionable and potentially damages the pipe. Other commenters including MidAmerican Energy Co. requested that pneumatic spike tests to 1.5 × MAOP be allowed when the resultant pressure complies with the limitations stated in the table in § 192.503(c).
C. IVP	Spike Test		Trade associations and pipeline industry entities including INGAA, GPA, and TPA asserted that PHMSA should eliminate the spike test requirement for establishing MAOP entirely. These commenters stated that the proposed

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			provisions went beyond what was required to reconfirm MAOP for an accepted margin of safety. These commenters further asserted that spike testing is not an appropriate technique for MAOP reconfirmation, and could result in unintended negative consequences without improving pipeline safety. They stated that spike testing is an aggressive and destructive technique that should be used only in cases in which time-dependent threats, such as a significant risk of stress corrosion cracking, exist.
C. IVP	Spike Test		Citizens groups, including Pipeline Safety Coalition, Environmental Defense Fund, and NAPSR expressed support for spike testing, stating that it would provide for increased pipeline safety. NAPSR further stated that the option of applying to use alternative technology or an alternative technological evaluation process would allow for some flexibility in cases in which a hydrostatic test is impractical. Environmental Defense Fund also suggested additional measures to mitigate emissions from methane gas lost during testing.
D. Require Assessments for Non-HCAs (MCAs)			The NTSB and multiple citizen groups supported the expansion of integrity management (IM) elements to gas transmission pipelines in areas outside those currently defined as HCAs. However, several entities including Pipeline Safety Trust stated that the limited suite of IM tools was insufficient and requested that the full suite of IM elements be applied to the additional pipeline segments. The NTSB also stated its disagreement with PHMSA's proposed highway coverage and stated its support of expanding the highway size threshold as NTSB had recommended in P-14-1. Some citizen groups expressed concern that the 15-year implementation period and 20-year re-inspection period was too long.
D. Require Assessments for Non-HCAs (MCAs)			While pipeline companies and trade associations generally supported PHMSA's efforts to expand IM beyond HCAs, many of them stated concerns over the time and cost required to identify MCAs, the efficacy of the changes, and the language and requirements regarding both the limitation of assessments to segments accommodating inline inspection tools and (re)assessment periods. Many groups requested a clear, concise set of codified requirements for IM outside of HCAs, to simplify the identification and recordkeeping.
D. Require	Allowable		Several commenters provided input on allowable assessment methods. AGA

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Assessments for Non-HCAs (MCAs)	Assessment Methods		suggested that PHMSA create a new subpart consisting of a clear and concise set of codified requirements for additional assessments, including new definitions regarding the limitation of assessments to segments accommodating inspection of instrumented inline inspection tools. Many trade associations and pipeline companies stated that they thought Direct Assessments could achieve a satisfactory level of inspection in place of costlier in-line inspection, especially given the additional detail added to in-line inspection in the proposal. API requested that PHMSA allow operators to rely on any prior assessments performed under Subpart O requirements in effect at the time of the assessment rather than limit the allowance to in-line inspections. Furthermore, other organizations supported AGA's proposal that mirrors the two-methodology approach used in the definition of High Consequence Areas (HCAs) in the existing § 192.903, which allows for identification based on class location or by the pipeline's potential impact radius.
D. Require Assessments for Non-HCAs (MCAs)	Allowable Assessment Methods		Entities including API and Atmos Energy requested clarification regarding assessment periods and reassessment intervals, as well as language regarding requirements for shorter reassessment periods. Lastly, AGA suggested that PHMSA define the term "Pipelines that can accommodate inspection by means of an instrumented in-line inspection tool" used in proposed § 192.710 and § 192.624, stating that providing the criteria that a pipeline must meet to be able to accommodate an in-line inspection would remove uncertainty and inconsistency in determining which pipelines meet PHMSA's proposed qualifier.
D. Require Assessments for Non-HCAs (MCAs)	Definition of MCA		Many respondents submitted comments on the proposed definition of MCA. API and other commenters stated that they preferred a new category as opposed to expanding the definition of HCA, whereas SoCalGas encouraged expanding the scope of HCAs rather than creating a new category. AGA and a number of other organizations expressed concern over the resource-intensive administrative task of identifying MCAs, especially pertaining to recordkeeping requirements. API asserted that the proposed provisions would limit operators' ability to prioritize resources for pipelines that pose the highest risk. They further stated that while they agree with the inclusion of all Class 3 and Class 4 locations, occupied sites,

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			and major roadways in the definition of MCA, they disagree with the proposed threshold of five buildings intended for human occupancy within the potential impact radius. They suggested that a more appropriate threshold would be more than 10 buildings intended for human occupancy, as that number is consistent with longstanding Part 192 Class location designations.
D. Require Assessments for Non-HCAs (MCAs)	Definition of MCA		Multiple groups such as AGI, INGAA, and Cheniere Energy also stated objections over various aspects of defining and identifying MCAs and provided suggestions such as removing the reference to "right-of-way" for designated roadways and the revising the definition of occupied site. In addition to requesting modifications to the definition of MCA, INGAA objected to the provided GIS layer for right-of-way determination, and suggested that PHMSA provide one database for roadway classification. Numerous trade associations and pipeline companies asked PHMSA to consider a qualifier that the definition of MCA only applies to pipelines operating at greater than 30% SMYS. EnLink Midstream suggested using a threshold level of 16" pipe diameter to identify pipelines that pose a greater risk.
E. Gathering Lines	API RP-80 and PHMSA's Definition of Gathering Line		Many trade associations, pipeline industry entities, and one municipality expressed opposition to repealing the use of API RP 80. Several trade associations commented that there was not sufficient justification for repealing the recommended practice. For example, commenters including GPA stated that no gathering line safety data was provided in the record to justify the proposed changes to either the definition of an onshore gas gathering line or the proposed criteria for regulating certain rural gathering lines, and questioned the data and analysis that was used to characterize the perceived risk. Trade associations expressed concerns that PHMSA did not consider certain required statutory factors, collect data to sufficiently understand the currently unregulated rural gathering lines, nor demonstrate the reasonableness and appropriateness of the proposal. Enterprise Products commented that API RP 80 is a straightforward and appropriate means for defining gathering lines based on a pipeline's function, rather than location, and that such an approach is consistent with the Pipeline Safety Act. Trade associations generally expressed concern about the

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			effect of the repeal and new definition effects on operators. API provided a discussion of the history, development and recent reviews of API RP 80, explained how the concepts, processes, and definitions outlined in API RP 80 are still applicable, and asserted that the current definition has received broad-based and consistent support over the years.
E. Gathering Lines	API RP-80 and PHMSA's Definition of Gathering Line		Citizen groups, including Pipeline Safety Coalition, Earthworks, Pipeline Safety Trust, and several state entities expressed general support for the proposed new definitions. The Public Service Commission of West Virginia (PSCWV) expressed support for the revised definition of a regulated gathering line, commenting that it is much clearer and less prone to varying interpretations. These groups also provided specific suggestions for revising definitions described below.
E. Gathering Lines	API RP-80 and PHMSA's Definition of Gathering Line		Trade associations, industry entities, state entities and citizen groups provided suggestions for modifying definitions to provide additional clarity, remove ambiguities contained in the proposed gathering-related definitions, ensure consistency regarding jurisdictional determinations under 49 C.F.R Part § 195, and reflect actual configurations of production facilities and sound engineering principles. Some commenters, while stating their opposition to revising the gathering line definitions, provided suggestions on the proposed definitions should PHMSA proceed with revising the definitions. Commenters requested clarification of the definitions of "Gathering line (Onshore)", "onshore production facility or onshore production operation", "gas processing plant", and "gas treatment facility" and new standalone definitions for the terms "farm tap" and "incidental gathering." For example, commenters highlighted the following phrases within the proposed definition of onshore production facility or onshore production operation as examples of inherently ambiguous: "does not necessarily mean" and "as may be commonly understood or contained in many contractual agreements." Some commenters further proposed specific revisions to the definitions. For example, providing technical detail on pipeline configurations and operations as justification, API proposed that the definition of the end of production occur at the isolation valve downstream of the final meter after the

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			furthermost downstream production facility used to measure the finished products prior to delivery for transportation into a pipeline system. Additionally, MPSC requested that PHMSA clarify the language in subsection (6) of the gathering line definition to include taps on production facilities or well heads.
E. Gathering Lines	API RP-80 and PHMSA's Definition of Gathering Line		Commenters stated that several of the proposed provisions associated with gathering lines would impose regulatory requirements on distribution lines. Safety Trust requested that PHMSA ensure that the proposed language is clear that there is no applicability to distribution systems, and also requested that the current definition including hoop stress criteria will be retained to distinguish transmission from distribution systems. AGA expressed its concern that the proposed new definition "gas treatment facility" will have an unintended impact on distribution systems. AGA recommended that PHMSA revise the definition of "gas treatment facility" to limit its application to gathering lines and expressly exempt distribution facilities. Pipeline AGA also commented on the proposed definition, stating that changes to the definitions associated with transmission and gathering lines would have a direct impact on distribution lines because the latter is defined in § 192.3 as a pipeline that is not a gathering or transmission pipeline. AGA continued that definitional changes that increase the number of miles of transmission line essentially do so by converting distribution or gathering lines into transmission lines. AGA commented that the proposed definition changes will have repercussions beyond this rulemaking since the number of transmission miles as reported to PHMSA is used by other regulatory programs
E. Gathering Lines	API RP-80 and PHMSA's Definition of Gathering Line		Several commenters suggested that PHMSA include diagrams with the definitions to improve clarity. To illustrate how the new definitions would be implemented, API requested that the diagrams included in API RP 80 be retained, or, alternatively, that similar diagrams be developed for the rule. Enterprise stated that it is critical that the Agency develop and propose clear and workable diagrams to assist operators in determining how the new definitions would be implemented.
E. Gathering	API RP-80 and		Many commenters expressed concerns that the proposed provisions affecting

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Lines	PHMSA's Definition of Gathering Line		gathering lines exceed the bounds of PHMSA's authority. Commenters emphasized that Congress established a framework for modifying gathering line regulations which mandates that regulatory changes be based on risk. Many commenters, including GPA Midstream and the Oklahoma Oil & Gas Association, asserted that PHMSA's proposed rulemaking did not follow this framework. Several commenters, including the IPPA, NDPC, and Virginia Oil and Gas Associations stated that gathering lines are the domain of state regulatory commissions.
E. Gathering Lines	API RP-80 and PHMSA's Definition of Gathering Line		Many commenters raised issues related to jurisdictional implications. API, for example, emphasized the importance of consistency in defining terms used in the federal rules, particularly those that have jurisdictional implications in both compliance and enforcement. They asserted their concerns over Jurisdictional Determinations under 49 C.F.R. Part § 195, and inconsistencies in the proposed language of Part §192. API offered several specific requests that would serve to maintain consistency with Part § 195 and avoid inconsistency in jurisdictional determinations of production operations. They also requested other specific revisions to ensure that the definition is not unnecessarily restrictive.
E. Gathering Lines	API RP-80 and PHMSA's Definition of Gathering Line		API and NAPSR expressed concerns regarding the proposed new approval process involving the Associate Administrator of PHMSA for approving deviations in the gathering pipeline definition (§ 192.3 Definitions), acknowledging that this concern also applies to other provisions in the proposed rule in which PHMSA introduces a new approval process by the Associate Administrator. NAPSR asserted that the authority for approval of deviations from the gathering line definition should reside with the entity that has the authority for administration and enforcement of pipeline safety, and offered revised language for the gathering line definition. API expressed concern that the proposed approval process involving the Associate Administrator of PHMSA would demand unnecessary operator resources, and also commented that the new process fails to involve other federal (e.g., OSHA) and state agencies responsible for the enforcement of safety standards. Commenters also identified examples of dual notification and authority of both PHMSA and State agencies in several

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			sections of regulations.
E. Gathering Lines	API RP-80 and PHMSA's Definition of Gathering Line		Several entities discussed farm tap lines in their comments. Two trade associations, the Independent Petroleum Association of America (IPAA) and Virginia Oil and Gas Association, requested that PHMSA clarify that it is not regulating production line farm taps. API commented that farm tap lines are service lines, not gathering lines, and requested that PHMSA incorporate a standalone definition for "Farm Tap," which API provided. GPA and EnLink Midstream urged PHMSA to be consistent in its definition of farm taps by using the definition of such service lines provided in the PHMSA proposed rule dated July 10, 2015 in §192.740. EnLink Midstream stated that the consistency would alleviate confusion in the industry regarding regulation of farm taps. One commenter requested that PHMSA address the integrity management of farm tap lines.
E. Gathering Lines	Regulating Class 1 and Higher-Risk Gathering Lines		Several trade associations and pipeline industry entities expressed concern regarding the proposed extension of certain pipeline safety requirements to the proposed subset of gathering lines. Many commenters stated that the proposed criteria are not focused on the higher risk assets. Dominion Transmission, commented that it is reasonable to implement regulatory oversight of pipelines with similar operating characteristics to transmission facilities, but not to apply the same regulations to small diameter, low-pressure gathering pipelines, which have characteristics that pose significantly lower safety and environmental risks. API opposed the proposed approach for rural gathering lines, stating that these lines are relatively lower risk assets. They cited the GRI report completed in 2000 for details on the research behind the Potential Impact Radius (PIR) definition, which they suggested provides a case for a risk-based approach to regulating gathering lines. NGA asserted that if PHMSA does expand scope as proposed, this would divert resources, undermine compliance efforts, and reduce overall pipeline safety. PPI asserted that the proposed extension of the regulatory safety requirements to gathering lines conflicts with other portions of 49 CFR Part 192 and creates onerous requirements for gas gathering operators.
E. Gathering	Regulating		Many trade associations and pipeline industry entities expressed concern

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Lines	Class 1 and Higher-Risk Gathering Lines		regarding the proposed pipe size criterion for extending regulatory safety requirements and suggested alternatives regarding the size and pressure. Several commenters stated that the proposed diameter requirement was arbitrary, and questioned PHMSA's justification for the requirements. PPI recommended that PHMSA further study the pipe size dimension threshold prior to revising the requirements. Several commenters suggested that PHMSA should instead apply the new safety standards only to larger diameter lines operating at a maximum pressure that exceeds 20 percent or more of SMYS. Multiple commenters stated that revisions to PHMSA's proposal should target the potentially higher risk gas gathering lines that are 16 inches in outside diameter and operate at a maximum pressure of 20 percent or more SMYS. NDPC stated that the 16-inch threshold is consistent with examples PHMSA used to illustrate that gathering lines are subject to the same types of failures common to other pipelines that the Agency regulates, and that it is also consistent with the GAO's August 2014 report entitled "Department of Transportation is Taking Actions to Address Rail Safety but Additional Actions are Needed to Improve Safety." Additionally, API also asserted that the current text does not clearly distinguish the differences between Type A, Area 1 and Type A, Area 2 lines, and suggested instead creating a "Type C" class of pipelines as an alternative to the currently proposed "Type A, Area 2."
E. Gathering Lines	Regulating Class 1 and Higher-Risk Gathering Lines		Several commenters addressed the applicability of regulations based on differences in materials from which gathering pipelines are made, for example steel and nonmetallic or plastic. PPI provided a detailed discussion of the characteristics of different materials in the context of the proposed rule, and suggested that the requirements should not be extended to nonmetallic materials. GPA suggested 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 would therefore be considered Type A as defined in proposed § 192.8. GPA recommended that the requirements should apply only to steel lines.

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			IPAA requested that an exemption be made for low-pressure plastic lines.
E. Gathering Lines	Regulating Class 1 and Higher-Risk Gathering Lines		Many concerns were raised over the table (81 FR 20827) that supports the determination of onshore gathering lines and regulated onshore gathering lines. Arkansas Public Service Commission (APSC), referring to Column 3 in the table (81 FR 20827) expressed concern over the loss of its inspection jurisdiction that would result from the change in the MAOP requirements, and offered suggestions regarding how to address its concerns by making revisions to the table that supports the definitions of Type A and Type B in Part 192 of the proposed rule. The APSC provided detailed examples of how the lack of clarity and detail in the table in the proposed rule would result in a reduction in the level of safety that the proposed rule would provide. Gas Piping Technology Committee (GPTC) provided several detailed comments to modify the table to be consistent with existing language.
E. Gathering Lines	Regulating Class 1 and Higher-Risk Gathering Lines		One commenter, EQT, requested that an economic criterion be included to allow operators to justify exemption of the proposed gathering line regulations. EQT requested a provision in 49 C.F.R. Part 192 that would provide regulatory relief for operators of economically-marginal, low-stress gathering lines that operate at low pressures, providing details on how it could be incorporated to allow for certain circumstances in which the operator of a Type B regulated onshore gathering line would not need to comply with the requirements in § 192.9(d). Specifically, EQT stated that if the economic burden imposed by such compliance would cause the operator to shut down or abandon the pipeline, an exemption should be granted.
E. Gathering Lines	Regulating Class 1 and Higher-Risk Gathering Lines		Several commenters expressed support for the proposed provisions on Class 1 and higher-risk gathering lines described in § 192.8 and § 192.9, and some suggested that they should be strengthened to be more protective. Earthworks expressed support for PHMSA's proposal to cover additional miles of previously unregulated lines that often have larger diameters and operate at higher pressures than typical gathering lines. Earthworks also expressed support for the proposed extension of requirements for emergency planning, corrosion protection, and damage prevention, but expressed concern that such requirements would not

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			apply beyond HCAs.
E. Gathering Lines	Regulating Class 1 and Higher-Risk Gathering Lines		Several citizen groups recommended that all gathering lines, regardless of Class Location, should be subject to Part 192 regulations or requested additional regulation of gathering lines. These commenters stated that when a gathering line functions as a transmission line, presents the safety risks of a transmission line and is indistinguishable from a transmission line other than by its position in a system relative to other pipeline facilities, it should be regulated the same as a transmission line. PSCWV and Responsible Drilling Alliance expressed concern that the proposed requirements for gathering lines are not adequate or sufficient for public safety given that the size and operating pressure of gathering lines exceeds those of transmission lines. These commenters also stated that the unique terrain and topography in areas such as Pennsylvania and West Virginia warrant more protective requirements.
E. Gathering Lines	Regulating Class 1 and Higher-Risk Gathering Lines		Several commenters provided input on the proposed requirements for Type A, Area 1 pipelines and Type A, Area 2 pipelines, stating that that they believed that the proposed rule may have included requirements and exclusions not intended by PHMSA. For Type A, Area 1 pipelines, commenters stated that they believed that PHMSA did not intend to exclude these pipelines from § 192.13 as well as from all of the requirements currently stipulated in § 192.319, but intended to exclude only the proposed § 192.319(d). These commenters stated that § 192.13 is the basis for application of regulatory requirements, and outlines the requirements and regulatory deadlines for construction, replacement or remediation of regulated pipelines. For Type A, Area 2 pipelines, commenters stated that § 192.9(d)(1) and (2) should be revised to include the exclusions intended by PHMSA. Specifically, commenters highlighted the proposed requirements regarding the use of leak detection equipment for Type A, Area 2 gathering lines when conducting leak surveys, suggesting that PHMSA may not have intended to include these requirements for gathering lines given that leaks that occur on larger diameter, higher pressure gathering lines would be detectable without leak detection equipment. Commenters also suggested that it may not have been PHMSA's intent to require Type A, Area 2 pipelines to

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			adhere to the requirements of all of subpart I, given that Type A, Area 1 pipelines are to be exempted from the proposed requirements of § 192.461(f), § 192.465(f), § 192.473(c), and § 192.478. Lastly, commenters suggested that PHMSA review the requirement of gathering line operators (both Type A and Type B) to comply with §192.619(e).
E. Gathering Lines	Subject All Gathering Lines to Reporting Requirements		Many citizen groups, including the NAPSR, Coalition to Reroute Nexus, Pipeline Safety Trust, Earthworks, and Pipeline Safety Coalition expressed general support for the reporting requirements proposed for gathering lines, and requested that these requirements be strengthened. These commenters agreed with PHMSA's proposal that all gathering lines, regardless of Class Location, should be subject to reporting requirements. Commenters emphasized that available data on unregulated facilities may be inaccurate and/or outdated, particularly where gas development has grown rapidly and surrounding communities have grown in response to gas development. Some commenters stated that the rule should be strengthened, requesting that PHMSA also include additional reporting-related requirements to enhance public safety, including participation in the National Pipeline Mapping System and mandatory one-call systems.
E. Gathering Lines	Subject All Gathering Lines to Reporting Requirements		Several commenters opposed the proposed reporting requirements. NAPSR requested that consideration be given to limit burdensome data reporting requirements on unregulated gathering line operators. One commenter stated that the proposed rule is not consistent with the information collection requirements in the Pipeline Safety Act or other federal laws and would impose an unnecessary burden on gathering line operators. Several trade associations stated that the proposed reporting requirements would have a large impact on the regulated community. For example, Louisiana Mid-Continent Oil and Gas Associations (LMOGA) stated that the new requirements unnecessarily duplicate existing provisions. Enterprise Products asserted that although the proposed rule, as written, requires only reporting and not full compliance with 49 CFR. Part 192 per se, an operator would have to comply with most of Part 192 in order to be able to complete the required reports. The Independent Producers joined both

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			API and GPA in stating that the reporting requirements on unregulated gathering lines are expensive, onerous, and not supported by a demonstrated pipeline safety benefit.
E. Gathering Lines	Subject All Gathering Lines to Reporting Requirements		Other concerns were raised regarding requiring certain reporting requirements for otherwise unregulated gathering facilities. For example, EnLink Midstream questioned the value of the proposed requirement to provide telephonic notice of incidents for otherwise unregulated gathering facilities, as very few details useful for analysis are typically available within the one hour timeframe required for telephonic notification. This commenter also expressed doubt that the reporting of safety-related conditions for the otherwise unregulated gathering pipelines on a sporadic basis would provide value in reaching conclusions to support a data driven analysis process. Enterprise Products commented that much of the information required by the current reporting forms does not exist for gas gathering lines, and that information such as MAOP and pipe characteristics is unlikely to be available. The commenter further detailed the risks that unknown or erroneous data of considerable variability will be generated in the reporting forms. Other commenters stated that given the parameters that would be used to determine whether a Class 1 gathering line is regulated, PHMSA is in effect imposing a retroactive requirement that is prohibited in 49 USC 60104. GPA stated that 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.
E. Gathering Lines	Subject All Gathering Lines to Reporting Requirements		To address these concerns, several commenters, including TPA, Enterprise, and EnLink Midstream proposed a modified data collection effort, which they asserted would serve in determining whether further oversight is warranted. These commenters requested that the reporting required for currently unregulated onshore gas gathering pipelines be limited to abbreviated annual and incident reports. Enterprise requested that PHMSA create a new incident report form for unregulated pipelines that requests information relevant to only those pipelines. Similarly, Enterprise also recommended that PHMSA create a new annual report form to segregate the reporting of pipeline data for unregulated

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			pipelines. Enterprise noted that many portions of the current annual report fail to distinguish between gathering or transmission pipelines, and similar to the incident report, much of the information requested is not typically available for unregulated lines. GPA similarly requested an abbreviated annual reporting form be developed. AGA, Kinder Morgan, and National Fuel Gas Supply Corporation (National Fuel) commented that the requirements should be modified to require only reporting of Safety Related Conditions for specific regulated gathering lines to ensure regulatory clarity. AGA expressed its concern that by including reporting requirements related to both MAOP exceedance and corrosion monitoring, PHMSA is proposing to subject the still unregulated gathering facilities to reporting requirements relating to provisions that are not applicable to those facilities.
E. Gathering Lines	Subject All Gathering Lines to Reporting Requirements		Several entities commented that the proposed timeline of six months was too short to require operators to identify regulated gathering line pipelines under the revised criteria. API, for example, asserted that there are practical challenges associated with complying with the proposed requirements for gathering lines due to the fact that these lines are often shorter segments of pipe, dispersed across a regional area in a nonlinear fashion, and configured in various ways to meet the needs of producers, which means they often do not run in continuous segments as transmission lines do. Enterprise Products also commented that the timeline was too short, specifically for unregulated gathering pipeline operators to obtain or attempt to recreate historical operating data, and then implement data collection practices into their operations.
F. Repair Criteria for HCAs and Non-HCAs			Citizen groups including NAPSR, Pipeline Safety Coalition, and Clean Water for North Carolina supported the proposed provisions that would strengthen the repair criteria for HCAs and non-HCAs.
F. Repair Criteria for HCAs and Non-HCAs			Trade associations and pipeline industry commenters generally expressed that the proposed provisions were too prescriptive and would impede operators from performing repairs based on risks. They further stated that the proposed provisions require operators to address anomalies indicated by ILI without taking

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			into consideration other factors that operators currently consider when optimizing plans to remediate anomalies, such as historical data geography and congestion of the ROW.
F. Repair Criteria for HCAs and Non-HCAs			Several of these organizations also stated that the rulemaking did not justify that the safety benefit of strengthened repair criteria outweighs the costs. Multiple pipeline industry entities stated that the proposed repair provisions in § 192.713 would increase the number of digs and asserted that the increased number of digs may not improve pipeline safety. Many pipeline industry commenters provided data regarding the number of historical excavations that have not resolved true immediate conditions.
F. Repair Criteria for HCAs and Non-HCAs			Several pipeline industry commenters disagreed with components of the proposed repair criteria and the repair methods that differed from industry standard ASME/ANSI B31.8S. For example, AGA stated that they opposed the inclusion of different repair criteria for different class locations, because this contradicts ASME B31.8S. Similarly, INGAA recommended that PHMSA allow operators to use repair methods in ASME B31.8S.
F. Repair Criteria for HCAs and Non-HCAs			AGA and several pipeline industry entities requested clarification regarding whether historically discovered conditions that met requirements at the time of discovery would now necessitate time-dependent repair. AGA recommended that the changes apply only to conditions discovered after the rule.
F. Repair Criteria for HCAs and Non-HCAs			Multiple commenters provided input on PHMSA's expansion of repair criteria to non-HCA areas. Citizen groups including NAPSR, Pipeline Safety Coalition, and Clean Water for North Carolina supported the rule's expansion of repair criteria to non- HCA areas. Clean Water for North Carolina stated that in addition to their support for strengthened repair regulations for MCAs, they also supported applying additional precautionary measures in areas in which there is evidence of a disproportionate impact of safety issues, particularly in low income or minority communities. Generally, trade associations and pipeline industry entities supported PHMSA's intention of providing guidance on repair criteria outside of HCAs, but disagreed with many of the specific components of the proposed rulemaking.

Topic	Subtopic	Sub-sub Topic	Comment
F. Repair Criteria for HCAs and Non-HCAs			Several trade organizations expressed concern that the proposed provisions for non-HCA areas would not encourage operators to allocate their resources to high consequence areas on a higher priority basis since this prioritization would not always be feasible due to the large quantity of new pipelines needing assessments. AGA requested that the rule explicitly prioritize immediate conditions within HCAs over immediate conditions in other locations when conditions are discovered simultaneously. AGA recommended that PHMSA adopt different terminology for “immediate repair conditions” inside and outside HCAs and that PHMSA create a new subpart to specifically address assessment requirements for outside of HCAs. They further recommended that PHMSA add a section within that subpart to cover repair criteria. Several other trade associations and pipeline industry entities echoed AGA’s recommendations. The MidAmerican also requested that remediation times for non-HCA immediate repair conditions be extended to 60 days.
F. Repair Criteria for HCAs and Non-HCAs			Several trade organizations and pipeline industry commenters, including INGAA, expressed concerns that the proposed rule would require pipeline operators to repair anomalies that do not threaten pipeline integrity response because PHMSA did not sufficiently distinguish between responding to ILI results and repairing confirmed injurious anomalies. Commenters stated that many anomalies that are identified by indirect measurements as requiring repair are later determined not to require repair upon examination in the field. Commenters requested (1) PHMSA change regulatory language to distinguish between ILI results and in-field examinations and (2) that the repair timeline begin with in-field examination and not ILI identification. INGAA suggested that PHMSA change regulatory language to differentiate between response, remediation, and repair and that PHMSA replace “repair” with “response” in the terms “two-year repair criteria” and “one-year repair criteria.” INGAA also requested that PHMSA further divide two-year response conditions into two-year response conditions and scheduled responses and similarly, divide one-year response conditions into one-year response conditions and scheduled responses.
F. Repair			Multiple commenters provided input on the proposed provisions on repair

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Criteria for HCAs and Non-HCAs			criteria for pipeline metal loss. Many trade associations and pipeline industry entities expressed disagreement that all dents with metal loss would be considered immediate repair conditions. These commenters requested that PHMSA's final rule address different kinds of dents separately. Many pipeline industry entities stated that dents with metal loss from "scratches, gouges, and grooves" are appropriate immediate repair conditions, while dents due to corrosion are lower risk and should be conditions scheduled for repair. Several organizations cited API Publication 1156: Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines and ASME B31.8: Gas Transmission and Distribution Piping Systems to support these claims. Several entities also recommended that PHMSA have different response timelines for dents depending on the location of the dents, because dents with bottom side metal loss are usually corrosion-related and low risk, while dents on the top of the pipeline with metal loss are likely to be from mechanical damage. INGAA proposed that dents with bottom metal loss be two-year schedule conditions.
F. Repair Criteria for HCAs and Non-HCAs			Multiple commenters also provided input on the proposed provisions that determine repair criteria for metal-loss affecting certain pipe with longitudinal seams. INGAA, AGA, and a pipeline industry entity generally supported immediate repair classification for the proposed provision in § 192.713(d)(1)(iv) "an indication of metal loss affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency or high frequency electric resistance welded or by electric flash welding." However, commenters requested that PHMSA not classify metal-loss affecting a detected longitudinal seam as an immediate repair condition if that seam was formed by high-frequency electric resistance welding. National Fuel requested that PHMSA categorize longitudinal seam metal loss based on a minimum metal-loss threshold rather than "an indication."
F. Repair Criteria for HCAs and Non-HCAs			Several commenters including AGA, Pauite, and DTE did not support the proposed inclusion of "any indication of significant seam weld corrosion" in § 192.713(d)(1)(vi). INGAA and AGA asserted that seam weld corrosion can only be conclusively determined by an in-field examination even though ILI in-line

Topic	Subtopic	Sub-sub Topic	Comment
			inspection tools are often employed to identify possible seam weld corrosion areas. Similarly, INGAA noted that ILI technology cannot distinguish between gouges and safe metal loss and requested that this condition be deleted from the two- and one-year response conditions lists. Several trade associations and pipeline industry entities requested that operators be allowed to perform excavations to validate ILI results before classifying a segment as a high priority repair.
F. Repair Criteria for HCAs and Non-HCAs			Multiple commenters also provided input on the proposed provisions that address repair criteria for cracks and crack-like defects. INGAA, API, and Piedmont strongly opposed the proposed provisions in § 192.713(d)(1)(v) stating that "any indication of significant stress corrosion cracking" (SCC) constitutes an immediate repair condition. Commenters requested that the regulations determine the repair condition of cracks and crack-like defects according to factors that capture the severity of the defect, such as predicted failure pressures or maximum depth.
F. Repair Criteria for HCAs and Non-HCAs			Several trade associations stated that including both metal loss and failure pressure criteria for determination of repair conditions is confusing and recommended that PHMSA establish a single metric. INGAA recommended making the repair criteria for cracking consistent with the repair criteria for metal loss, and suggested that PHMSA consider anomalies with 80% depth-based cracking immediate conditions for this reason. INGAA also recommended that PHMSA adopt a failure pressure ratio approach for cracking.
F. Repair Criteria for HCAs and Non-HCAs			Multiple trade associations and pipeline industry entities also expressed concerns that the proposed provisions requiring "an operator to reduce the operating pressure of its affected pipeline until it can remediate the immediate repair conditions" are unnecessarily conservative. INGAA asserted that the proposed pressure reduction requirements for non-HCAs are more stringent than the pressure reductions requirements for HCAs and several commenters offered alternative methods for determining appropriate operating pressure reductions.
G. Requirements for Assessment			Several commenters supported strengthening the requirements on the selection and use of assessment methods for pipelines requiring assessment, and many

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Methods			trade associations and industry entities submitted comments with criticisms of PHMSA's proposed revisions, technical examples, and recommendations for the final rule.
G. Requirements for Assessment Methods			The NTSB stated that it is unclear whether the proposed provisions on assessment methods would ultimately address all elements of NTSB's Safety Recommendations P-15-18 and P-15-20. NTSB referred to its study Integrity Management of Gas Transmission Pipelines in High Consequence Areas that discussed the limitations of direct assessment and stated that relying only on direct assessment as a primary avenue for IM is ineffective; direct assessment is used to evaluate pipeline corrosion threats only. In its comments to PHMSA, NTSB provided some of the conclusions of its study: There are many limitations to direct assessment, including that (1) it is limited to the detection of defects attributed to corrosion threats, (2) it only covers very short sub-segments of the pipeline, (3) it relies on the operator's selection of specific locations for excavation and direct examination, and (4) it yields far fewer identifications of anomalies compared to in-line inspection. NTSB urged PHMSA to require pipeline operators to augment the direct assessment method wherever it is used with appropriate additional integrity assessment methods such as magnetic flux leakage, ultrasonic testing, and tests directed at determining the integrity of the pipe coating.
G. Requirements for Assessment Methods	Additional Allowable Methods		Many industry entities recommended deleting the language in §192.921(a)(7) regarding the requirement that an operator must receive a "no objection" letter from PHMSA in order to use other technologies for integrity assessments. INGAA and Kinder Morgan encouraged PHMSA to embrace newer technologies, such as ILI, without imposing unnecessary restrictions such as the proposed pre-approval process to use alternative technologies for MAOP reconfirmation in proposed §192.624.
G. Requirements for Assessment Methods	Additional Allowable Methods		CPUC recommended that direct assessment (ECDA, ICDA or SCCDA) should not be the sole assessment methods except in the cases of short pipeline segments and elbows. Rather, CPUC recommended adding the following sentence to the §192.921(a): "If methods such as ECDA, ICDA or SCCDA are

Topic	Subtopic	Sub-sub Topic	Comment
			used, such methods shall complement other methods, such as pressure testing or ILI.” Kinder Morgan asserted that newer technologies provide operators with information that can be used for integrity management and safe operation of the pipe, and that in contrast, pressure tests are a blunt tool that merely inform an operator whether the pipeline segment "passed" or "failed." They further stated that in many situations the newer technologies are less costly, both in terms of dollar cost to the operator as well as less overall societal costs in the form of environmental impacts. Kinder Morgan recommended that PHMSA encourage technology development and deployment. NGA expressed its support of PHMSA's initiative to allow additional tools.
G. Requirements for Assessment Methods	Allowing Direct Assessment Only if Line Not Piggable		NTSB commented that PHMSA’s proposal to revise the pipeline inspection requirements to allow the direct assessment (DA) method to be used only if a line is not capable of inspection by internal inspection tools directly conflicts with the recommendations of their pipeline safety study, Integrity Management of Gas Transmission Lines in High Consequence Areas, which recommended that PHMSA develop and implement a plan for eliminating the use of direct assessment as the sole integrity assessment method for gas transmission pipelines.
G. Requirements for Assessment Methods	Allowing Direct Assessment Only if Line Not Piggable		Many industry entities argued that PHMSA’s proposed changes to §192.921 limiting DA to unpiggable lines are not technically justified. Several entities, including AGA and API expressed opposition to limiting operators’ ability to use DA for pipeline assessments unless all other assessment methods have been determined as unfeasible or impractical. While API commended PHMSA on providing necessary clarifications in the regulations on these assessment methods, it argued that operators should not be restricted under proposed changes to §192.923, §192.927, and §192.929 to performing assessments by the proposed methods. PG&E requested that PHMSA recognize that although a pipeline may be considered piggable, it does not mean that ILI technology is available, and provided specific suggestions for revision. Similarly, AGA stated that free-swimming flow-driven ILI tools are often not compatible with intrastate transmission lines for a number of reasons, stating that certain conditions must

Topic	Subtopic	Sub-sub Topic	Comment
			exist in order to assess a pipeline by ILI and obtain valid data. AGA provided a suggested definition for "able to accommodate inspection by means of an instrumented in-line inspection tool."
G. Requirements for Assessment Methods	Allowing Direct Assessment Only if Line Not Piggable		Trade associations asserted that DA is a proven assessment technique that works in addressing the threat of corrosion. INGAA stated that the criteria for when direct assessment can be used should depend on whether direct assessment can provide the necessary information about the pipe condition rather than whether other assessment methods are possible. AGA commented that it is not aware of any industry study that would suggest that DA does not work effectively to identify corrosion defects in certain circumstances, which it describes in its comments. In addition, it stated that DA is a predictive tool that identifies areas where corrosion could occur, including time-dependent threats, while other methods can only detect where corrosion has resulted in a measureable metal loss. Atmos Energy commented that limiting the use of direct assessment only to those segments that are not capable of inspection by internal inspection tools is not consistent with other requirements of Subpart O.
G. Requirements for Assessment Methods	Assessment Methods and Consideration of Uncertainties		Several commenters addressed uncertainties with regard to allowable pipe integrity assessment methods and tools as proposed in § 192.921 and § 192.493. Issues raised include uncertainty of ILI locations, tool tolerances, SIV factors, and detection and sizing of pipeline anomalies. NAPSR expressed its agreement with and support for PHMSA's revisions, and several commenters opposed the proposed changes.
G. Requirements for Assessment Methods	Assessment Methods and Consideration of Uncertainties		Many comments expressed concerns with the proposed provisions in §§ 192.921(a) and 192.921(a)(1) regarding uncertainties. Multiple commenters stated that operators should be able to run the appropriate assessment or ILI tools for the threats that are known or likely to exist on the pipeline based on its condition. Atmos Energy commented that ASME/ANSI B318.S requirements should be the standard to which operators are required to follow. EMP proposed that PHMSA add "significant" to make a distinction between insignificant threats, and offered specific language to address its concerns. PG&E commented on the proposed provisions in §192.921(a)(1), requesting that PHMSA provide

Topic	Subtopic	Sub-sub Topic	Comment
			guidance as to how to explicitly consider the numerous uncertainties associated with ILI location, detection and sizing of pipeline anomalies, and suggested that PHMSA allow industry guidance and best practices to be used where practical. Some commenters expressed concern that PHMSA proposed to add requirements surrounding the detection of anomalies which many inline inspection tools could not meet. These commenters stated that there are no tools designed to find girth weld cracks, and that most incidents caused by girth weld crack have third party excavation damage as a contributing factor. Commenters further stated that this is a threat that is best handled by procedures that require caution around girth welds during excavation and backfilling procedures. DEO expressed a concern with the compliance requirements, specifically the uncertainty of ILI vendors being in compliance with these standards. DEO provided the example that the proposed provisions specify tool tolerances of 90%, and ILI vendors have said they can only agree to a tool tolerance of 80%.
G. Requirements for Assessment Methods	Assessment Methods and Consideration of Uncertainties		Several entities commented on the proposed qualification requirements in §192.921(a)(1), expressing concern that they are redundant with existing operator qualification regulations under IM at §192.915 and proposed revisions to §192.493 incorporating industry ANSI standard on ILI personnel qualification. Multiple entities proposed changes to remove such redundancies and improve clarity; for example, to delete reference to "girth welds" and qualifications from the proposed regulation.
G. Requirements for Assessment Methods	Assessment Methods and Consideration of Uncertainties		INGAA and a pipeline industry entity expressed their agreement with PHMSA that the use of spike hydrostatic testing is appropriate for time-dependent threats such as stress corrosion cracking. INGAA, however, proposed changes to §192.506, and the cross-reference in §192.921(a)(3), to limit the spike testing requirement to time-dependent threats, to test to a minimum of 100% SMYS instead of 105%, and to provide an alternative for use of an instrumented leak survey. INGDA and INGAA agreed that spike testing is the best means of testing a pipeline with a history of environmental cracking, such as stress corrosion cracking that has developed while in service. INGAA also noted that a spike test may be of value for in-service pipelines where metallurgical fatigue is of

Topic	Subtopic	Sub-sub Topic	Comment
			concern. INGAA further stated that pressure cycling should not need to be included in §192.506, and that PHMSA should amend §§ 192.506 and 192.921(a)(3) to limit spike testing only to those segments with stress corrosion cracking.
G. Requirements for Assessment Methods	Assessment Methods and Consideration of Uncertainties		Multiple entities commented in support of using Guided Wave Ultrasonic Testing and the proposed changes to Appendix F. Citizen group NAPSR expressed its agreement with and support for the proposed revisions to this Appendix. APGA applauded PHMSA for including guidelines for Guided Wave technology; however it cautioned the specification of only specific GUL Wavemaker G3 and G4, which use piezoelectric transducer technology, as acceptable technology. APGA recommended that Magnetostrictive Sensor (MsS) technology also be included as an acceptable guided wave technology. APGA stated that at least one of its members reported good results using this technology for guided wave assessment of an unpiggable segment of transmission line.
G. Requirements for Assessment Methods	Assessment Methods and Consideration of Uncertainties		Other commenters recommended additional changes to Appendix F, such as stating that qualified GWUT Equipment Operators are trained to understand the strengths, weaknesses and proper applications of each wave mode and should have the freedom to select the appropriate and most effective wave mode(s) for the given situation. PG&E requested that PHMSA recognize that this technology is used at other locations other than casings as implied in the introductory paragraph, and also commented that double ended inspections are not always required to meet the specification. Multiple commenters expressed concerns over a reference to a specific manufacturer of equipment.
G. Requirements for Assessment Methods	Reference to NACE, API, and ASNT standards		Reference to NACE, API, and ASNT standards Many commenters provided input on the topic of incorporating international standards by reference. The Pipeline Safety Trust urged PHMSA to require that these standards, like all incorporated standards, be made available to the public free of charge. The NTSB supported the proposed provisions to incorporate standards by reference, stating that it addresses two recommendations from its study Integrity Management of Gas Transmission Pipelines in High Consequence Areas.

Topic	Subtopic	Sub-sub Topic	Comment
G. Requirements for Assessment Methods	Reference to NACE, API, and ASNT standards		Reference to NACE, API, and ASNT standards Many commenters offered support of the NACE standard as guidance documents or best practices, but not as mandatory, comprehensive requirements. However, API and many other commenters stated that the proposed provisions include too many prescriptive requirements that would limit operators to certain methods and stifle technological advances, and that operators should not be restricted to the approved PHMSA assessment methods. Many commenters requested that PHMSA revise its proposal to eliminate incorporating "recommendations" as regulatory requirements, and provided examples as rationale. For example, NiSource that historically, when incorporating consensus standards, PHMSA has stated only that the "requirements" of the consensus standard must be followed. NiSource stated that this allows the operator the flexibility to use other practices if a consensus standard recommendation is not practical or an operator has other practices that meet the intent of the "recommendation."
G. Requirements for Assessment Methods	Reference to NACE, API, and ASNT standards		Reference to NACE, API, and ASNT standards Commenters including NACE International expressed concern about instances where the proposed provisions incorporating industry standards go beyond what is specified in a standard or is applying selected sections of a standard rather than the entire standard. NACE stated that most standards specify that the entirety of the standard must be applied and used. Quoting its own language, NACE stated that NACE International Standards include the following language on this matter, "For accurate and correct application of this standard, the standard must be used in its entirety. Using or citing only specific paragraphs or sections can lead to misinterpretation and misapplication of the recommendations and practices contained in this standard." NACE added that similar language is present in the standards of other organizations. NACE further explained that NACE Standards do acknowledge that specific actions and practices are not included for every circumstance due to the complexity of situations and conditions that may be encountered or required. Thus, they stated that additional requirements, such as those associated with high consequence areas (HCAs), may be needed.

Topic	Subtopic	Sub-sub Topic	Comment
G. Requirements for Assessment Methods	Reference to NACE, API, and ASNT standards		Reference to NACE, API, and ASNT standards Several commenters opposed to incorporating standards by reference questioned the benefit, provided examples to illustrate their concerns, and suggested alternatives to the proposed provisions. EMP provided an example in which it asserted that some of the requirements in NACE standard SP0102-2010 would be counterproductive to pipeline safety. AGA, which commented that it does not support the incorporation by reference, nor the required application, of standards that are not widely used and adopted by natural gas pipeline operators, proposed that PHMSA maintain references to existing standards and allow for incorporation of new standards.
G. Requirements for Assessment Methods	Reference to NACE, API, and ASNT standards		Multiple commenters expressed concerns about references that are outdated, under revision, or eliminated. PG&E suggested that PHMSA consider delaying adoption of these references until the updated standards are published or allow operators to justify alternative decisions from sections of the standard which are no longer applicable to pipeline operations due to technology and application advancements. GPA Midstream Association stated that one concern of incorporating standards by reference is the slow process of updating to more current editions, whereas standards setting organizations tend to keep pace with advances in technological change resulting in up-to-date standards.
G. Requirements for Assessment Methods	Requirements for Direct Assessment	Direct assessment for stress corrosion cracking (SCCDA):	Multiple commenters supported the proposed changes to §192.929 on direct assessment for SCCDA. NAPSR expressed its agreement with and support of the revisions to this subsection §192.929 on the requirements for using SCCDA. Spectra Energy Partners provided comments in support of the proposed inclusion of explicit requirements for SCCDA. SEP expressed its belief that SCCDA is a diligent, practicable approach for assessments for stress corrosion cracking for cases in which the pipeline has not previously experienced an in-service failure caused by stress corrosion cracking, and provided specific edits to make the requirements for SCCDA clearer and more practicable.
G. Requirements for Assessment Methods	Requirements for Direct Assessment	Direct assessment for stress	Several other commenters questioned or opposed the proposed changes to §192.929. Several commenters including API expressed their support of NACE standards SP0204-2008 for SCCDA, but recommended that PHMSA not exceed

Topic	Subtopic	Sub-sub Topic	Comment
		corrosion cracking (SCCDA):	those established industry standards. NACE International, referencing the text in the proposed rule that cites overprotection or high negative potentials as a factor in stress corrosion cracking of pipelines, stated that it is unaware of any conclusive data that this is the case. In addition, NACE commented that the proposed rule goes beyond what is stated in NACE Standard SP0204 by requiring a minimum of two above-ground surveys and three direct examinations.
G. Requirements for Assessment Methods	Requirements for Direct Assessment	Direct assessment for stress corrosion cracking (SCCDA):	AGA commented that SCCDA is a proven assessment technique that works in addressing the threat of stress corrosion cracking. INGAA proposed to clarify the way in which SCCDA can be used as an integrity assessment method, asserting that SCCDA is a valid method to assess for the stress corrosion cracking threat in gas pipelines for segments that are susceptible to, but have no history of, stress corrosion cracking. INGAA further asserted that when there is a history of stress corrosion cracking, then an ILI or pressure spike test should be used.
G. Requirements for Assessment Methods	Requirements for Direct Assessment	Direct assessment for stress corrosion cracking (SCCDA):	Other commenters provided specific technical comments regarding these provisions. TransCanada asserted that applying the NACE "significant SCC" definition as the threshold for immediate repair is both overly conservative and overly complicated, and suggested that PHMSA adopt the threshold of "noteworthy" as defined in ASME STP-PT-011. EMP expressed that it agrees that factors referenced in Sections §192.929(b)(1) and §192.929(b)(4) should be considered as part of the data gathering and post assessment steps; however EMP asserted that PHMSA should provide clarity by including a referenced standard that provided guidance to operators on how these factors should be considered.
G. Requirements for Assessment Methods	Requirements for Direct Assessment	External corrosion direct assessment (ECDA)	AGA commented that external corrosion direct assessment (ECDA) is a proven assessment technique that works in addressing the threat of external corrosion. AGA also asserted that the ECDA process is often more effective than ILI in providing operators with a better understanding of critical conditions external to the pipeline, such as cathodic protection (CP) and coating conditions. NACE International observed that within the proposed provisions, there are multiple instances where a bifurcation in corrosion control and pipeline integrity management for external corrosion control is created wherein the regulations

Topic	Subtopic	Sub-sub Topic	Comment
			governing natural gas pipelines significantly differs from those used for hazardous liquids pipelines. NACE International asserted that it is unaware of any fundamental, technical basis why differences in external corrosion control would be different for these pipelines.
G. Requirements for Assessment Methods	Requirements for Direct Assessment	Internal Corrosion Direct Assessment (ICDA)	NAPSR expressed its agreement with and support for the proposed revisions to § 192.927 on ICDA. Multiple entities from the pipeline industry and trade associations commented that the proposed provisions should simply incorporate the NACE standard by reference, and that the requirements should not exceed those established industry standards. PG&E, in its comments on the issue of incorporating standards by reference, requested replacing "as required by" with "in accordance with" so that operators meet the requirement but have flexibility in implementation technique if the industry publishes new techniques to perform ICDA feasibility studies. NACE International expressed its belief that ICDA is an acceptable standalone methodology for assessing pipeline integrity as described in NACE Standard SP0206.
G. Requirements for Assessment Methods	Requirements for Direct Assessment	Internal Corrosion Direct Assessment (ICDA)	TPA commented that while it agrees that internal corrosion direct assessment is an important part of a good integrity management plan, it disagrees with the intervals related to post assessment evaluation and monitoring found in §192.927(c)(4)(ii), and recommended instead a performance-based approach, with a monitoring frequency that reflects the results of previous integrity testing and risk factors specific to a particular ICDA region so that operators can focus on the highest risk areas of the system. Atmos Energy commented on proposed mandated monitoring for all ICDA regions as potentially excessive, and recommended that proposed language be deleted and current §192.927(4)(ii) language be restored. Another commenter recommended that PHMSA remove the proposed notification requirement prior to performing an ICDA, noting that operators currently provide this information as part of other annual reporting.
H. Requirements for Validating and Integrating Pipeline Data			Many stakeholders expressed agreement with PHMSA that verified and validated data is important for data integration and threat analysis, yet had concerns about the specific proposed changes to the requirements for validating and integrating pipeline data. NTSB expressed support for the proposed

Topic	Subtopic	Sub-sub Topic	Comment
			additions to the IM analysis requirements and commented that expanded pipeline record requirements are a significant improvement in the management of pipelines through their service lifecycle.
H. Requirements for Validating and Integrating Pipeline Data			Trade associations and a pipeline industry entity commented on the feasibility of threat identification, data gathering and integration, and PHMSA's incorporation of ASME/ANSI B31.8S by reference. API stated that while the attributes listed in proposed §192.917 should not pose a major burden on the industry, not all of the attributes listed may be feasible to obtain in practice. Enterprise Products stated that including just four or five attributes that point to a specific conclusion would be more useful than the lengthy list of attributes in the proposed provisions. Spectra Energy Partners fully supported codifying the ASME/ANSI B31.8S into §192.917.
H. Requirements for Validating and Integrating Pipeline Data			INGAA and TPA expressed concern that the proposed provisions are more prescriptive than the ASME standard. INGAA also commented that incorporating language from ASME/ANSI B31.8S into the regulatory text while keeping the existing incorporation of reference would introduce confusion, asserting that it is unclear whether PHMSA intended to expand the current requirements of §192.917(b). INGAA further stated that the current regulatory language that operators must "consider" similar non-covered segments should be retained, rather than adopting the proposed provisions that would mandate that all aspects of ASME/ANSI B31.8S be applied to similar non-covered segments. They further stated that many of the data elements required by ASME/ANSI B31.8S are not available for legacy pipelines, which can fall into the category of similar non-covered segments.
H. Requirements for Validating and Integrating Pipeline Data			Several commenters provided input on PHMSA's proposed requirements to address subject matter expert (SME) bias. INGAA stated that PHMSA should delete the undefined references to SME bias listed in §192.917(b)(2) and replace the text with more general language to include peer reviews and external SME verification, citing this alternative as more consistent and clear. National Fuel stated that using outside technical experts for bias control would post an unnecessary cost to operators of pipelines. AGA asserted that this measure was

Topic	Subtopic	Sub-sub Topic	Comment
			already industry standard practice and that it is not necessary to codify it into regulation. PG&E also suggested improvements to the section, stating that there is not an existing industry standard to provide guidance on what constitutes an outside technical expert to perform this specific function, and that PHMSA should provide further guidance on this topic.
H. Requirements for Validating and Integrating Pipeline Data			Several industry trade groups provided input on the proposed language in §192.917(b)(3) that requires operators to identify and analyze the spatial relationship among anomalous information and store the information in a common location including a GIS system. AGA stated that PHMSA should clarify why storing data on a GIS system alone is insufficient. TPA stated that it disagreed with the proposed language in §192.917(b)(3) and commented that this requirement would impose a financial burden on smaller operators. PG&E asserted that the language in this section should be removed entirely since it was not clear how to comply with these requirements.
H. Requirements for Validating and Integrating Pipeline Data			Multiple commenters disagreed with the requirement in § 192.917(e)(3) of the proposed rule for operators to perform annual cyclic fatigue analyses if an operator identifies cyclic fatigue as a threat. INGAA and National Fuel suggested that cyclic fatigue is an uncommon risk for natural gas pipelines and asserted that PHMSA did not provided significant technical justification for this analysis requirement. Trade associations and pipeline industries proposed several alternative requirements for the conditions under which cyclic fatigue analyses should be required.
H. Requirements for Validating and Integrating Pipeline Data			INGAA and others also asserted that PHMSA should clarify the timeline for validating and integrating data, stating that given the expansion of § 192.917 (b)(1) to non-covered segments, operators must be provided sufficient time to come into compliance with the rule.
I. Functional Requirements for Risk Assessments			Citizen groups supported PHMSA's revisions to strengthen functional requirements for risk assessment models. The Pipeline Safety Trust stated that risk assessment models currently used by pipeline operators are inadequate and raised concerns that the proposed provisions did not go further to advance risk assessment quality.

Gas NPRM: Summary of Comments

Topic	Subtopic	Sub-sub Topic	Comment
I. Functional Requirements for Risk Assessments			Multiple trade associations and pipeline industry entities acknowledged the importance of risk assessments, but believed that the proposed provision in § 192.917(c) were too prescriptive. Several pipeline industry entities emphasized their voluntary efforts to improve their risk models and disagreed that the industry's risk models needed further regulation.
I. Functional Requirements for Risk Assessments			Many commenters emphasized that different pipeline systems are susceptible to different threats and believed that operators are best suited to determine which threat analyses are relevant to their system. Multiple pipeline industry commenters expressed that the proposed rule would require operators to substantially expand datasets but contribute little benefit to risk identification. These entities emphasized that integrating unnecessary datasets would distract from more productive datasets, risk factors, and safety efforts.
I. Functional Requirements for Risk Assessments			AGA and several pipeline industry entities requested that PHMSA give operators discretion to select which data sets to incorporate into risk assessments for their system. The Indiana Utility Regulatory Commission suggested that PHMSA consider a performance-based regulatory approach over the proposed prescriptive provisions.
I. Functional Requirements for Risk Assessments			Some commenters requested that PHMSA specify what is meant by "validate" and "verify" in the proposed provisions. These commenters expressed doubts regarding the technical feasibility of implementing the proposed regulations in § 192.917(c). Several commenters noted that some data required for validating risk assessment models is not available and proposed that operators be permitted to apply conservative values or values determined using engineering judgement. Pipeline industry entities Southwest Gas Corporation, Pauite Pipeline, and Consumers Pipeline expressed concerns that developing the newly required datasets would demand ILI tools that their pipelines are not configured to tolerate. These commenters stated that gathering these datasets would present costs that were not captured by PHMSA's PRIA.
I. Functional Requirements for Risk			Multiple commenters expressed concern that the proposed revisions would make operators' current relative risk models invalid and necessitate that operator's transition to quantitative/probabilistic risk models. API commented that

Topic	Subtopic	Sub-sub Topic	Comment
Assessments			PHMSA appears to require a quantitative risk assessment (also referred to as a quantitative or probabilistic risk model). API asserts that proposed § 192.917(c)(1-5) can only be satisfied through quantitative or probabilistic risk models, and that these models are not useful or appropriate for the analysis, prediction or prevention of the low frequency, high consequence events such as San Bruno. API commented further that the probabilities of certain infrequent circumstances and conditions occurring at a single location and single time is so low that the quantitative or probabilistic models would not identify them because there are no statistics available from which to predict them. Commenters emphasized the high costs associated with implementing quantitative risk models, which can include the procurement of specialist expertise, development of new datasets, and transition to a GIS and/or new database management systems.
I. Functional Requirements for Risk Assessments			Multiple commenters emphasized the importance of basing rules on industry standards and expressed concerns that the proposed rule would incorporate industry standards without the standards' accompanying context. AGA asserted that the proposed requirements deviate from industry standards and that PHMSA did not provide sufficient justification for this departure.
I. Functional Requirements for Risk Assessments			The AGA and multiple pipeline industry commenters expressed concerns that the proposed rule does not provide a timeline for implementing new risk assessment requirements, thereby implying that operators must implement new requirements by the rule's effective date. Multiple trade associations and pipeline industry entities requested that operators be permitted to develop their own implementation schedules, and several commenters proposed specific implementation schedules. For example, pipeline industry entity Enterprise Products requested that PHMSA include a phase-in period for operators to incorporate these requirements into their Integrity Management Programs for both data integration (addressed in § 192.917(b)) and risk assessments, and recommends a 2-year period for operators to implement them. API requested a 5-year period.
I. Functional			Several commenters also requested that PHMSA postpone modifying the risk

Topic	Subtopic	Sub-sub Topic	Comment
Requirements for Risk Assessments			assessment provisions until outcomes from the PHMSA Risk Modeling Work Group are finalized.
J. Applying Knowledge Gained Through IM			Commenters generally acknowledged the value of an integrity program and evaluating interactive threats, yet several commenters identified vague language in the proposed revisions. Commenters requested that the requirement that risk assessments "lead to better understanding…" and produce a "risk characterization consistent with industry experience" be removed or clarified. Kern River requested clarification regarding which elements of § 192.917 need to be included in an operator's risk model and which elements only need to be included in the overall integrity management plan, stating that integrity assessment method determination, repair decisions, preventive and mitigative measures selection, root cause analysis, and similar pipe studies all play a part in the overall integrity management plan and have at times overlapping, but also unique, requirements for data gathering, integration, and threat analysis.
J. Applying Knowledge Gained Through IM			Several commenters also requested that PHMSA revise the requirements in § 192.935(a) to remove the requirement for operators to perform all the listed measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. These commenters stated that requiring operators to perform all of the measures listed in § 192.935(a) negates the need for a risk analysis, as the rule would require that operators perform each of the listed actions regardless of whether conditions warrant these actions or whether past efforts have been taken. INGAA suggested that PHMSA should keep the existing language which states that an operator must base the additional measures on the threats the operator has identified to each pipeline segment.
K. Corrosion Control			Citizen groups including Coalition to Reroute Nexus, PROTEC, and Pipeline Safety Trust supported the proposed changes regarding corrosion control and pipeline condition monitoring. Other groups including Earthworks and NAPSR suggested that PHMSA enact more stringent requirements. The Pipeline Safety Coalition, PSCWV, and Pennsylvania Public Utility Commission (PAPUC) stated that not all gathering pipelines should be exempt from corrosion

Topic	Subtopic	Sub-sub Topic	Comment
			monitoring.
K. Corrosion Control			Several trade associations including AGA objected to the expansion of the corrosion control provisions, stating that current regulations and efforts by transmission operators are already sufficient, that new provisions are not justified and are overly burdensome, and that the projected costs are greater than the benefits. Many of these commenters expressed support for current industry standards such as NACE, and stated that some of the new requirements are not aligned with these standards. Some commenters requested clarification regarding whether the proposed provisions are intended to include transmission, distribution, and gathering lines while other commenters commented on whether gathering lines should be included, especially for ACVG and DCVG inspections in proposed § 192.461.
K. Corrosion Control			Several commenters provided input on the proposed provisions on external corrosion control in § 192.461. Many commenters stated that coating holiday surveys are not always feasible and that PHMSA should not limit tools for performing coating surveys to the two types specified in § 192.461(f). For example, INGAA stated that PHMSA did not provide justification for requiring coating surveys such as DCVG and ACVG to be used to detect coating issues after construction or after performing a repair or replacement. INGAA further stated that PHMSA should allow operators to use other assessment technologies such as close interval surveys and high resolution geometry in-line inspection tools to detect and manage post-construction and post-repair and replacement conditions that contribute to external corrosion. NACE expressed concern that DCVG and ACVG surveys do not address the stated goal of identifying coatings that impede CP, and objected to setting specific thresholds for these tests. Similarly, INGAA stated that if the requirements for operators to perform coating surveys using SCVG and ADVG are finalized, the proposed voltage drop threshold value in § 192.461(f) should be eliminated. Commenters also stated objections or suggested limitations to the timeframe proposed in § 192.461(f) regarding when these surveys should be performed, stating that the three month timeline is inconsistent with the one-year allowed to install cathodic protection

Topic	Subtopic	Sub-sub Topic	Comment
			after construction of a pipeline in existing § 192.455(a)(2).
K. Corrosion Control			Numerous trade associations and pipeline companies stated concern regarding the new requirements for interference surveys under proposed § 192.473. Commenters including Atmos Energy Corporation and AGA expressed doubt regarding the ability of individual operators to obtain the necessary information from electric transmission providers. American Public Gas Association (APGA) and INGAA urged PHMSA to limit this new requirement to only specific transmission lines, such as those pipelines subject to the threat of stray electric current. Commenters including INGAA also stated that additional time should be allowed for implementation of remediation measures, and provided timeframes from one year to at least 18 months.
K. Corrosion Control			Multiple commenters considered the proposed changes to requirements for internal corrosion control in § 192.478 to be overly prescriptive, particularly with regard to gas monitoring and the list of corrosive constituents. INGAA stated that transmission operators are already taking comprehensive steps to address internal corrosion under Subparts I and O of Part § 192, and that proposed § 192.478 should be eliminated. Atmos Energy Corporation and INGAA asserted that the internal corrosion monitoring timeline proposed in § 192.478(d) is unreasonable, particularly for pipeline systems that are not susceptible to internal corrosion. They further stated that mitigation of internal corrosion is necessary only if a pipeline is transporting, or has the potential to transport, corrosive gas.
K. Corrosion Control			Commenters expressed concern that the proposed revision to 192.465(d), as written, would apply equally to deficiencies found on transmission pipelines and distribution pipelines, and requested that PHMSA clarify that proposed changes would apply only to transmission lines. Additionally, INGAA asserted that PHMSA should allow exceptions to the one-year deadline proposed in § 192.465, stating that these remediation activities could require environmental permits and other government approvals.
K. Corrosion Control			Several industry entities commented on the proposed revisions to Appendix D to Part 192: Criteria for Cathodic Protection and Determination of Measurements,

Topic	Subtopic	Sub-sub Topic	Comment
			referenced in § 192.465(f). INGAA stated that the proposed criteria in Appendix D for determining the adequacy of cathodic protection is too narrow, and that all industry standards provide for additional methods of assessing IR drop. These commenters recommended that PHMSA follow the applicable paragraphs of NACE Standard Practice SP0169. Enterprise also noted that Appendix D should be consistent with Part § 195.571.
K. Corrosion Control			Commenters stated that the proposed changes to Appendix D would apply to distribution pipelines as well as transmission pipelines, and expressed concern that PHMSA has offered neither justification nor an estimate of the impact on either transmission or distribution systems. They requested that PHMSA clarify that the proposed changes to Appendix D apply only to transmission lines.
L. Preventative and Mitigative Requirements to Address External Corrosion and Internal Corrosion in HCAs and Actions to Address Integrity Issues			Citizen groups including NAPSR and Pipeline Safety Trust agreed with and supported the proposed changes to preventive and mitigative (P & M) requirements to address internal and external corrosion in HCAs, and suggested strengthening the proposed provisions.
L. Preventative and Mitigative Requirements to Address External Corrosion and Internal Corrosion in			While supporting certain aspects of the proposed provisions covering preventive and mitigative requirements to address external corrosion and internal corrosion in HCAs, many trade associations such as INGAA and AGA, as well as pipeline companies including Atmos Energy Corporation and Dominion East Ohio objected to the newly listed internal and external corrosion requirements in § 192.935. Many of these entities including INGAA stated a preference for allowing operators the flexibility to implement control actions based on their own judgment of the severity of the threat. In general, many organizations stated

Topic	Subtopic	Sub-sub Topic	Comment
HCAs and Actions to Address Integrity Issues			that individual sections of the proposed provisions were too broad and prescriptive, and would incur greater costs without justification. Some commenters recommended that PHMSA reference ASME standards for implementing P & M measures, and others stated concern that some language is not consistent with NACE standards.
L. Preventative and Mitigative Requirements to Address External Corrosion and Internal Corrosion in HCAs and Actions to Address Integrity Issues			Several commenters objected to multiple proposed aspects of internal corrosion control such as identification of threats, monitoring, and filtering, and stated that operators should have flexibility to implement P & M measures. For example, INGAA opposed the proposed requirement in § 192.935(f) that requires operators to install continuous gas quality monitoring equipment at all points in which gas with potentially deleterious contaminants enters the pipeline. INGAA recommended that § 192.935(f) apply only to pipeline segments with a history of internal corrosion, and stated that this would be consistent with the required risk analysis that is performed to determine whether preventive and mitigative measures are necessary. Similarly, Atmos Energy recommended that gas sources be monitored only at those sources suspected, in the judgment of the operator, of having deleterious gas stream constituents and that such monitoring can be either real time or periodic. INGAA stated that PHMSA should modify proposed § 192.935(g) to require that operators conduct periodic indirect inspections only where a pipeline segment has a known history of corrosion.
L. Preventative and Mitigative Requirements to Address External Corrosion and Internal Corrosion in HCAs and Actions to Address			Several commenters also provided input on the proposed amendments to the actions that would be required to be taken to address integrity issues outlined in § 192.933. Several commenters urged PHMSA to align the requirements in § 192.713 (permanent field repair of imperfections and damages) and § 192.933, and that many of the comments provided for § 192.713 apply to § 192.933 as well. INGAA and other commenters provided input on specific elements of threat identification and repair criteria under § 192.933, such as metal loss and seam weld corrosion, in the context of ASME and other standards.

Topic	Subtopic	Sub-sub Topic	Comment
Integrity Issues			
M. Management of Change			Citizen groups including NAPSR generally agreed with and supported the proposed management of change provisions, stating that these provisions would enhance pipeline safety. Several pipeline companies and trade associations opposed the proposed management of change provisions, stating that the provisions are generally too broad and would be applied to many routine activities that already have established procedures. AGA opposed the proposed provisions, stating that they would create a new requirement for each transmission operator to have a formal management of change process to document and evaluate all changes to pipelines and processes. They further stated that the proposed revisions are unnecessary due to the current industry progress related to management of change and voluntary adoption of industry consensus standards.
M. Management of Change			Several commenters opposed the proposed addition of four types of changes (design, environmental, operational, and maintenance), asserting that these elements are not included in current industry standards or recommended practices. Similarly, INGAA asserted that PHMSA should eliminate the changes it proposed to § 192.13 that go beyond the recommendations of ASME/ANSI B31.8S. These commenters stated that PHMSA significantly underestimated the impact and burden caused by codifying and expanding the scope of management of change.
M. Management of Change			Several commenters including AGA, API, and INGAA opposed the proposed immediate implementation of management of change provisions, with some commenters requesting an implementation period of one to five years. These commenters stated that the significant proposed regulatory changes would need to be incorporated into existing management of change processes, and that additional time is needed to complete this in an effective manner. Many commenters also expressed concern over the retroactive application the proposed management of change provisions.
N. Inspections of Pipelines			Most stakeholders supported the intent of the proposed provisions requiring inspections of pipelines following extreme weather events but requested further

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Following Extreme Weather Events			clarification on terminology. Pipeline Safety Trust, NAPSR, and EnLink Midstream supported the § 192.613 proposed amendments.
N. Inspections of Pipelines Following Extreme Weather Events			Some commenters expressed concern with the broad requirements of an "inspection" and requested further clarification regarding what an inspection following an extreme weather event would entail. In addition, these stakeholders stated that the proposed definition of an extreme weather event was vague and requested clarification. INGAA stated that operators are already required to have procedures to ensure a prompt and effective response to emergency conditions in §192.615, and suggested that to avoid duplicative regulation, PHMSA should instead modify § 192.615(a)(3) to incorporate additional specificity on weather events that may trigger a prompt and effective response.
N. Inspections of Pipelines Following Extreme Weather Events			Many commenters objected to the proposed timeframe, stating that the 72-hour requirement listed in the rule could be problematic. Commenters stated that PHMSA should allow operators to determine when an impacted area can be safely accessed and that pipeline operators are best positioned to evaluate the balance between the safety and the need for inspections to ensure continued safe operation of their systems. INGAA stated that the 72-hour requirement should either be replaced with a more general statement such as "as soon as practicable" or that PHMSA should create a process to request an exception to the requirement.
N. Inspections of Pipelines Following Extreme Weather Events			LMOGA stated that extreme weather events vary significantly by region and commented that not all local geography and extreme weather events are the same. They further stated that the 72-hour definition may be too prescriptive depending on the extreme weather event. They stated that because Louisiana is subjected to many unusual extraordinary events such as spillway openings, high/low river flows, and rainwater flooding, PHMSA should clarify what "other events" means and how the cessation of an event is determined.
O. Grace Period (with notice) for Reassessment			PHMSA received one comment regarding the 6-month grace period for the 7-year reassessment interval from a trade organization expressing general support of the proposed provisions and requesting that PHMSA clarify that the six month

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Interval			extension begins after the close of the seven calendar year reassessment interval period, consistent with the 2011 revision to 49 U.S.C.
P. Reporting of MAOP Exceedance			Trade associations, citizen groups, and pipeline industries supported PHMSA's codification of statutory reporting requirements for MAOP exceedance for transmission lines.
P. Reporting of MAOP Exceedance			API and GPA objected to MAOP exceedance reporting requirements for unregulated gathering pipelines. GPA stated that PHMSA did not sufficiently weigh the benefits of reporting MAOP exceedance against the hurdles to compliance for unregulated gathering pipelines. GPA also questioned whether PHMSA has the authority to require unregulated gathering pipelines report MAOP exceedance, since complying with this reporting requirement would necessitate that unregulated gathering pipelines establish MAOP. Citizen groups, including Earthworks, the NAPSR, the Pipeline Safety Coalition, and the Pipeline Safety Trust, supported the inclusion of unregulated gathering pipelines in this section, stating that it would improve pipeline safety.
P. Reporting of MAOP Exceedance			Several commenters suggested revisions to streamline and improve the clarity of the rule. NGA expressed concern that the proposed provisions could apply to distribution systems and suggested that PHMSA clarify that reporting requirements for MAOP exceedance only apply to transmission pipelines. Additionally, Spectra Energy Partners requested that PHMSA require reporting of MAOP exceedance only when the operator is unable to respond to MAOP exceedance within the timeframe required elsewhere in the rule.
Q. Seismicity			Several stakeholders provided input on the proposed provisions requiring the consideration of the seismicity of a geographic area when identifying and evaluating all potential threats to a pipeline segment. CPUC supported the proposed provisions and recommended adding text that would require consideration of any significant localized threat that could impact the integrity of the pipeline. CPUC further commented that operating conditions on the pipeline must also be a factor when operators identify local threats.
Q. Seismicity			Some commenters including PG&E and the NGA requested further clarification regarding what would constitute a seismic event for §§ 192.912(a)(3),

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			192.917(b) and 192.925(b)(2). AGA requested clarification on proposed § 192.917(a)(3) regarding whether operators are expected to conduct a one-time investigation on the risk of seismicity and geology, or if there is an expectation of a frequency requirement for re-investigation.
R. Safety Features on Inline Inspection Tool Launchers and Receivers			Stakeholders including Dominion Transmission and TPA provided input on PHMSA's changes to the requirements for safety when performing maintenance activities that utilize launchers and receivers for inserting and removing maintenance tools and devices. TPA supported the §192.750 additions, but stated that §192.750 should list the regulations by pipeline components and not pipeline maintenance. In addition, TPA suggested PHMSA revise the language to allow eighteen months after the effective date of the rule to comply with the provisions. This change would allow for more time to plan, budget, and complete the work safely. Citizens groups such as Pipeline Safety Trust and NAPSR supported the proposed provisions in §192.750.
S. General			Some citizen groups provided input on the cost analysis in the PRIA. EDF stated that the PRIA reasonably addressed uncertainty and lack of information surrounding certain key data assumptions. EDF further stated that the PRIA aligned with Office of Management and Budget guidance on the development of regulatory analysis for rulemakings. They stated that PHMSA used conservative values when making best professional judgments, and requested that PHMSA move quickly to finalize the rule. Pipeline Safety Trust assert that the costs included in the PRIA for verification of MAOP verification, data gathering, record maintenance, and data integration for lines subject to integrity management rules result from current integrity management regulations, and should not be attributed to this rulemaking. They further stated that the PRIA should be amended to remove these costs related to lines within High Consequence Areas (HCAs).
S. General			Many commenters including INGAA, AGA, AGL Resources, and Piedmont stated that the PRIA underestimated the cost impacts of increased material verification, record keeping, and MAOP confirmation requirements. AGL asserted that complying with the proposed record requirements would involve

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			increased labor and investment costs that should be quantified in the final RIA. AGA stated that it was unclear whether or how the PRIA incorporated material verification costs related to material documentation, plan creation, revisions, and testing. NYSEG asserted that the PRIA underestimated the cost impact of the proposed rule on smaller local distribution companies with combined transmission and distribution systems. They estimated that if the proposed rule were implemented, segments covered by the integrity management program would grow from 10 percent of the transmission system mileage to over 80 percent of the system mileage.
S. General			Some stakeholders provided input on the estimated number of miles that PHMSA used to determine the regulatory impact of the provisions in the proposed rule. For example, INGAA stated that it assumed the mileage estimated by PHMSA for estimation of MAOP confirmation, material verification, and integrity assessments outside HCAs to be accurate with the addition of reportable in-service incident since last pressure test data. INGAA also asserted that the mileage estimated for MCA transmission pipes should be done on the per-foot basis instead of per-mile basis because these pipes are likely to be an aggregation of short pipeline segments that are one mile or shorter in length. The North Dakota Petroleum Council asserted that definitions of onshore production operations and onshore gathering lines would dramatically increase the number of miles of regulated gathering wells beyond the mileage estimates in the PRIA.
S. General			Some commenters asserted that the financial impact of the proposed rule would be immense, and that because operators would not be able to bear these costs alone, they would likely pass the costs on to the ratepayers. For example, American Public Gas Association stated that all of their member utilities purchase gas and pay transportation charges to transmission pipelines to deliver gas from the producer to the utility. They asserted that ratepayers would pay for the costs that would be incurred by their transmission suppliers to comply with this rule. Similarly, Indiana Utility Regulatory Commission requested that PHMSA consider the costs to ratepayers in its cost analysis. Other commenters stated that this rule could force operators to take significant portions of their

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			pipelines out of service while they are brought into compliance, and that the PRIA failed to recognize that the Federal Energy Regulatory Commission (FERC) requires interstate natural gas pipelines operators to provide demand charge credits to customers when service is disrupted.
S. General			Some commenters stated that the proposed rule may cause abandonment of pipes and that these impacts should be considered in the final RIA. Commenters also stated that if a pipe is no longer economic to operate, yet FERC does not grant abandonment authority, a pipeline company would be forced to either operate a pipeline that may not meet PHMSA standards or undertake expensive replacement projects. They further stated that while operators may seek to recover the costs of replacement projects through rate increases, in a competitive pipeline market where operators are forced to discount their pipeline rates in order to retain customers, these costs might be too great to recover. Similarly, IPAA stated that the PRIA failed to account for the costs that could be incurred by operators if pipeline infrastructure is abandoned because the cost that would be required to comply with the rule would necessitate this abandonment. PSCWV stated that the abandonment of wells and pipelines could cause an environmental and economic liability for state regulators if operators abandon wells and pipelines without proper clean up.
S. General			Several commenters provided input on the proposed use of the social cost of carbon (SCC) and the social cost of methane (SCM) in the PRIA. Environmental Defense Fund and National Resource Defense Council supported the use of SCC and SCM methodology in the PRIA; however, these commenters stated that the estimates for SCC and SCM were likely too conservative and that the values should be higher than those used in the PRIA. These commenters stated that PHMSA should encourage the Interagency Working Group on Social Cost of Carbon to regularly update the SCC and SCM as new economic and scientific information emerges. API stated that the proposed use of the SCC and SCM to calculate the benefits of emissions reductions were flawed due to the discount rates used by PHMSA.

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			They asserted that PHMSA used low discount rates that led to a liberal damage estimate. In addition, API and Industrial Energy Consumers of America asserted that the SCC values used by PHMSA inappropriately impose global carbon costs on domestic manufacturers, which damages the industry's ability to compete internationally. AGA stated that the process used to develop the social cost of methane values in the PRIA did not undergo sufficient expert and peer review. INGAA stated that PHMSA overestimated the amount of greenhouse gas emissions that the rule would reduce.
S. General			Trade associations asserted that PHMSA did not fulfill its statutory obligation to consider the environmental impacts of the proposed safety standards. Trade associations stated that the proposed Environmental Assessment (EA) inadequately considered the environmental consequences of hydrostatic pressure testing, inline inspections, excavations, and MAOP verification. Trade associations expressed concerns that while PHMSA had addressed the emissions avoided under the proposed rule, it had not addressed the extent to which the proposed rule would increase emissions. AGA and INGAA noted that operators need to purge lines of natural gas before conducting hydrostatic tests or removing pipelines from service for replacement or repair. These commenters stated that the proposed regulation would increase methane emissions by increasing the number of hydrostatic tests, pipeline replacements, and pipeline repairs required, and asserted that the EA did not take the increased emissions from these blowdowns into account. INGAA asserted that not considering these methane emissions constituted a violation of the PSA and failure to "engage in reasoned decision making." INGAA also suggested that the methane emissions resultant from this rulemaking would run counter to the President's goals of reducing methane emissions.
S. General			EDF and Pipeline Safety Trust commissioned a study from M.J. Bradley & Associates (MJB&A), which calculated the extent to which the proposed rule would result in blowdown emissions. MJB&A found that potential methane emissions resultant from the proposed rule would increase annual methane emissions from natural gas transmission systems by less than 0.1 percent and

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			increase annual methane emissions from transmission system routine maintenance/upsets by less than one percent. MJB&A also noted five mitigation methods (gas flaring; pressure reduction prior to blowdown with inline compressors; pressure reduction prior to blowdown with mobile compressors; transfer of gas to a low-pressure system; and reduction of the length of pipe require blowdown using stopples) that if implemented, could decrease blowdown emissions by fifty to ninety percent. MBJ&A calculated that the societal benefits of methane reduction outweighed the mitigation costs for all mitigation options considered. Based on this study, EDF asserted that while the marginal increase in emissions from the proposed rule would be small, the total emissions from blowdowns would nonetheless be significant. They stated that PHMSA should require operators to select and implement one of the mitigation options and report to PHMSA information about their blowdown events such as the mitigation option selected and the amount of product lost due to blowdowns required by the rule. EDF also stated that if operators do not mitigate blowdown emissions, they should be required to provide an engineering or economic analysis demonstrating why mitigation is deemed infeasible or unsafe.
S. General			AGA stated that the EA did not address other environmental impacts resultant from hydrostatic pressure testing. AGA noted two anticipated water-related impacts: (1) hydrostatic pressure testing's water demand could aggravate water scarcity in already water-scarce environments and (2) the water used in hydrostatic tests could introduce contaminants if disposed on-site (or be very expensive to transport to off-site disposal). AGA explained that wastewater from hydrostatic tests could include hydrocarbon liquids and solids, chlorine, and metals. AGA also asserted that the EA did not adequately consider the land disturbances that could result from the proposed hydrostatic testing requirements. AGA also stated that the EA did not take into account that performing inline inspections and modifying pipelines to accommodate inline inspection tools would generate waste and disturb natural lands. AGA explained that operators

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			must clean pipelines prior to conducting inline inspections or modifying pipelines for inline inspection tools, and that this cleaning could produce large volumes of pipeline liquids, mill scale, oil, and other debris. AGA expressed concerns that the proposed EA did not discuss these environmental impacts associated with requiring MAOP verification, given that PHMSA anticipates that most affected pipelines would verify MAOP using ILI and pressure testing. AGA also provided input on the local environmental impacts of the proposed increased testing and inspection. AGA expressed concerns that the EA had (1) underestimated the quantity of excavations that would be required under the proposed rule and (2) inadequately assessed the environmental impacts of those excavations. AGA asserted that the EA had insufficiently considered the extent to which more excavations would generate water and soil waste. AGA also suggested that the proposed rule may induce operators to modify or replace pipelines, and that these modifications and replacements may affect land beyond existing rights of way. AGA asserted that this additional land area should be considered in the EA. Trade associations raised several technical issues regarding the EA. AGA expressed concerns that PHMSA provided insufficient information about methods used to calculate values in the Environmental Assessment and that this insufficient documentation interfered with stakeholders' ability to provide comments on the values that PHMSA chose. INGAA asserted that the proposed rule fell short of several legal obligations under the National Environmental Policy Act (NEPA), stating that the EA does not provide the required "hard look" at environmental impacts, that the EA did not adequately discuss the indirect and cumulative effects of the proposed rule, and that the EA's purpose and need statement do not fulfill NEPA's instructions. INGAA also expressed concern that PHMSA did not consider sufficient regulatory alternatives, stating that the EA considered solely the proposed rule, one regulatory alternative, and the no action alternative. INGAA stated that given the many provisions of the proposed rule, this approach was too limited.

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S. General			Some trade associations and pipeline industry entities provided input that the PRIA failed to account for the indirect effects of operators shifting resources in order to comply with the proposed rule. For example, AGA stated that the PRIA did not consider the potential indirect impacts the rule might impose on distribution lines. They asserted that the magnitude and prescriptiveness of the proposed rule would require distribution companies with intrastate transmission and distribution assets to reassign their limited resources to transmission lines. Some commenters stated that PHMSA did not consider that the proposed rule would divert resources away from voluntary safety programs their companies are initiating, stating that these voluntary safety measures would be scaled back as a result of the proposed rule. For example, AGA stated that accelerated pipe replacement programs that replace aging cast iron, unprotected steel pipe, and vintage plastics pipe, would lose resources as operators shift staff and capital to comply with this rule. They further asserted that, failing to replace these pipes would delay reductions in methane emissions from old, leaky pipes.