Liquid Pipelines

Agency	Policy/Rule/Action	Burden Created	Cost to Industry	Affected Entities	Alternatives (if applicable)
PHMSA	Proposed Rulemaking, "Pipeline Safety: Safety of Hazardous Liquid Pipelines"	PHMSA proposes a number of changes to its pipeline safety regulations. The liquids pipeline industry shares the same goal as PHMSA (to prevent accidents that impact people and the environment) and is supportive of PHMSA making adjustments to its pipeline safety regulations that achieve this objective. However, PHMSA's initial proposal raised major concerns surrounding overly broad or unnecessarily conservative requirements that did not prioritize risk, resulting in a diversion of resources to lower risk activities. Specific areas of concern in PHMSA's proposed hazardous liquids pipeline rulemaking include: gravity lines, gathering lines, post-extreme weather event inspections, ILI of non-high consequence areas (non-HCAs), leak detection systems in non-HCAs, repair criteria for immediate conditions, piggable HCA lines and other miscellaneous issues. To address these concerns, API and AOPL comments requested PHMSA ensure the proposed regulation does not: 1) pose additional, unintended safety risks for pipeline personnel, 2) fail to incorporate the proven application of good engineering judgment and the consideration of facts and science in operating pipelines, 3) ignore valuable advancements in the science and technology of pipeline integrity management, 4) improperly analyze the benefits and costs of the proposed rules, nor 5) impose new requirements without careful understanding of their integration with existing pipeline regulations and the operational feasibility of the proposed rules. In response, in a pre-publication version posted online in January 2017, PHMSA added language to protect the safety of personnel in the post-extreme weather event inspection requirement, limited ILI smart pig inspections in non-high consequence areas to onshore and piggable transmission lines, extended some implementation and compliance deadlines, and	PHMSA's failure to consider the full range of impacts of its proposal resulted in a significant gap between the industry-analyzed costs of approximately $600 million annually versus PHMSA's estimated $22 million annually.	Liquids Transmission Pipeline Operators	API and AOPL recommend the following adjustments to make the finalized hazardous liquid rule a workable, cost-effective pipeline safety regulation: **Repair Criteria is Unworkable** – PHMSA should modify the new integrity management repair criteria to address the omission of seam defects and align the severity thresholds commensurate to the required response. An example of one of many potential fixes to this section is requiring immediate repair of a likely or possible crack defect greater than 70% of nominal wall thickness, inclusive of coincidental or interacting corrosion, regardless of dimensions or where the likely or possible crack defect depth cannot be determined as the ILI feature signal strength has reached full saturation. **Integrity Assessment Applies Over-Conservatism** – Address PHMSA's practice of requiring multiple "stacked" safety factors with regulatory language that allows operators to consider uncertainties in reported inspection results in a conservative, aggregate manner, rather than individually when identifying anomalies. Additionally, discuss with industry the appropriate use of statistical and probabilistic methods for assessing risk. **Inappropriate Pipe Seam Assessment** – Allow operators to select the most appropriate ILI tools given the potential threats specific to that pipeline. **Ensuring Engineering Critical Assessments are Fit-for-Purpose** – Recognize the known levels of conservatism within technically proven fracture mechanics models and not apply additional, artificial levels of conservatism on top of these. **Expanded Application of Engineering Critical Assessments (ECAs)**– Avoid unnecessary "immediate" repair responses causing unwarranted pipeline shutdowns by allowing use of ECA when assessing dents and corrosion of or along a longitudinal seam weld. Specifically, while it was proposed as a 270-day condition but is currently a 180-day condition, strict application of the regulation to remediate "corrosion of or along a longitudinal seam weld" does not offer the opportunity for proper integrity management. This criteria does not distinguish between ordinary corrosion crossing the seam, which generally does

		dropped new repair criteria for non-HCAs and overly broad repair criteria for “any” indication of significant stress corrosion cracking. While these modifications are welcome changes, API and AOPL believe the following additional adjustments are necessary before the rule is finalized to make it a workable, cost-effective pipeline safety regulation: **Repair Criteria is Unworkable** - PHMSA continues to propose unworkable changes to the criteria used to identify and assess the need to make pipeline repairs. PHMSA proposes regulatory requirements based on specific pipe anomaly conditions, such as stress corrosion cracking (SCC) and selective seam weld corrosion (SSWC), even though pipeline ILI inspection technology does not characterize pipe anomalies as such. **Integrity Assessment Applies Over-Conservatism** - The methods PHMSA proposes for assessing corrosion are excessively and unnecessarily conservative. The results are wasteful preventive maintenance actions on pipe sections that do not pose a threat to public safety or the environment. **Inappropriate Pipe Seam Assessment** - PHMSA proposes requiring assessments for all forms of pipe with a seam weld. An impractical impact of this mandate would be that operators have to run an ILI tool on a pipeline with no history of or presence of risk factors for a seam defect. **Ensuring Engineering Critical Assessments are Fit-for-Purpose** - PHMSA’s proposed language on engineering critical assessments (ECAs) is new, was not provided in the Notice of Proposed Rulemaking and therefore was not subject to public notice and comment, and contains very specific requirements for how operators are to analyze anomalies, all of which make it unworkable.			not pose a threat and SSWC, which does pose a threat, meaning a substantial number of unnecessary assessments and repairs are required simply because the location of a feature. Resources may be inadvertently directed, and the numerous investigations would likely impact the public due to the effort to perform the assessments and repairs. As well, improvement of ILI tool resolution is resulting in the identification of smaller and smaller defects, many below mill tolerance. An example is very shallow dents with very shallow metal loss calls being classified as immediate conditions. Experience has shown that many of these features, when dug, are non-injurious, as suspected prior to excavation. Not allowing ECA of dents with interacting threats will similarly continue a misdirection of resources to lower priority risks. ECAs are a key tool in integrity management to ensure threats are clearly understood from an engineering perspective and avoid misdirection of resources toward non-injurious pipeline features, so as appropriate, industry stands ready to partner with PHMSA to develop fit-for-purpose guidelines. **Lack of Piggability Exception for Short, Low-Risk Lines** – Exempt short, low-risk lines from proposed piggability requirements. The new integrity management repair criteria should be modified to avoid imposing unsubstantiated constraints, which will impose excessive costs on industry. **Deep Water Inspection Clarification** – define onshore underwater pipeline facilities located at depths greater than 150 feet under the surface of water subject to additional inspection as excluding portions which are buried or installed beneath the floor or bottom of the water body.

		Expanded Application of Engineering Critical Assessments (ECAs)- Despite recognizing the benefits of ECAs and proposing their use in many places, PHMSA seems to disallow ECA for dents with interacting threats, such as corrosion or cracking. If not allowed and all dents associated with metal loss, cracks, or stress concentrators are considered to have the same severity, operators will incur unnecessary costs diverting limited resources to areas that would yield no added pipeline safety benefit. Similarly, ECAs should be allowed for assessing corrosion of or along a longitudinal seam. **Lack of Piggability Exception for Short, Low-Risk Lines** – The absence of an in-line inspection exception for piping of short distances between nearby facilities or within them, commonly referred to as "stump lines," forces operators to divert inspection resources to low risk equipment. **Deep Water Inspection Clarification** - At least one PHMSA Region may be misapplying a 2016 reauthorization law provision on pipelines in more than 150 feet deep of water. The intent of Congress is to address pipelines in a water depth greater than 150'. Congress specifically had in mind a pipeline resting on the bottom of a waterbody greater than 150' deep. However, one PHMSA region is adding the soil depth below the water body bottom to the water depth to reach the threshold. For example, a pipe installed with horizontal directional drilling 45' deep in the soil below the bottom of a water body only 110" in depth of water for a total soil-water depth of 155' would fall into this type of PHMSA region misapplication of the provision. However, this does not represent the same type of safety threat as a pipe resting on the bottom of a water body exposed to greater risk probability and consequences and for that reason was not the intent of Congress. PHMSA should ensure all regions apply this provision consistent with Congressional intent of water body depth.			

Liquid Pipelines

PHMSA	Incorporate latest edition of industry consensus standards, most notably API Standard (Std.) 653, *Tank Inspection, Repair, Alteration, and Reconstruction*	The version of API Standard (Std.) 653 for repair, alteration and reconstruction of storage tanks, currently incorporated by reference, does not allow for fitness-for-service assessments, or risk-based inspections. This leads to operators wasting resources performing unnecessary inspection and maintenance on tanks before they demonstrate a need for servicing. A fitness-for-service assessment process would allow operators to use this tool to collect data and implement safeguards to maintain tank integrity, while not requiring tank inspections at impractically frequent intervals. The fitness-for-service criteria included in the latest version of API Std. 653 is very stringent and will allow operators to ensure tank integrity without the need to spend millions of dollars on unnecessary tank inspections. While the issue with API Std. 653 is the most important, generally speaking, delays in PHMSA's adoption of published Industry standards have prevented implementation of best practices. Additionally, PHMSA should consider repealing or at least revising 49 C.F.R. Part 195.501(b), which delineates the four-part test for identifying covered tasks. The current regulations require each operator to produce its own individual covered task list. As written, Part 195.501(b) is vague and ambiguous, and causes confusion for operators in determining which tasks should be included in their Operator Qualification (OQ) programs. Part 195.501(b) was administered with an over weighted focus on documentation and causes a disproportionate amount of effort and resources expended by operators to pass PHMSA inspections versus focusing on improving operator performance and pipeline safety. Additionally, there is an API Recommended Practice (RP) 1161, *Pipeline Operator Qualification (OQ)*, 3rd edition, to assist operators, but it is not incorporated by reference by PHMSA regulations. This is a highly burdensome process for operators and has led to a lack of uniformity, thereby increasing the potential for	Pertaining to incorporation of API Std. 653, storage tank maintenance costs are between $3 and $4 million per outage, which is significant given the number of tanks in a facility and the frequency prescribed in the version of API Std. 653 currently incorporated by reference.	Midstream companies with aboveground storage tanks	PHMSA should incorporate by reference API Standard 653, 5th Edition (November 1, 2014). Many other standards and best practices have been developed by industry that we encourage DOT to adopt. These standards are typically performance-based and provide operators with a variety of methods to demonstrate compliance. Such documents are developed and consistently applied for small, medium and large operators. In addition, they are subject to peer review, using the ANSI standard for open and collaborative involvement by all parties (operators, regulators, technical consultants and the public), and are science-based. Oftentimes, regulations that are difficult to interpret or, in some cases, appear contradictory or duplicative of technical standards lead to poor compliance. PHMSA should strive to incorporate by reference the latest version of any updated or changed consensus standards within one year of the publication date of the modified document. Incorporating by reference industry standard API RP 1161 would provide clarity, transparency, and predictability for operators in identifying OQ covered tasks. Additionally, doing so would promote consistency and simplify PHMSA's inspection and enforcement review. Updating OQ regulations with an intent to improve operator performance would also relieve the administrative burden on operators brought on by an over emphasis by PHMSA on documentation. The following documents should be adopted by reference in the regulatory section detailed: **49 CFR Part 195.452 Pipeline Integrity Management in High Consequence Areas:** Adopt by reference API RP 1160, *Management of Liquid Pipeline Integrity Management*, 2nd edition. Additionally, the 3rd edition is underway and when it is published, it should be considered by PHMSA for incorporation. **49 CFR Part 195 Subpart E Pressure Testing:** Adopt by reference API RP 1110, *Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide*, 6th edition. Additionally, API will soon issue API Technical Report 1179, *Hydrostatic Testing as an Integrity Management Tool*, 1st edition, and PHMSA should proactively consider incorporation of that document by reference.

		inconsistent enforcement. Additionally, this performance based standard has been expanded by PHMSA in recent enforcement to include tasks beyond what industry typically has determined should be included. The current regulation also includes outdated editions of industry standards, including but not limited to the following: ASME B16.9, ASME B16.34, ASTM A105, ASTM A694, MSS SP-75, and MSS SP-97. It is understood that the regulator needs to ensure that these documents do provide for safe operations, but many times, PHMSA is a part of the development, giving little excuse for delay in incorporation.			**49 CFR Part 195 Subpart C Design Requirements, Subpart D Construction and Subpart F Operations and Maintenance:** Consider revising and replacing much of these regulations with an incorporation by reference of ASME B31.4, *Pipeline Transportation Systems for Liquids and Slurries*, 2016 edition. Specifically, for Subpart D and some elements of the others, API has published RP 1177, *Steel Pipeline Construction Quality Management Systems*, 1st Edition, and it should be reviewed for incorporation. **49 CFR 195 Subpart H Corrosion Control:** Review applicable NACE standards which could replace large portions of this subpart.
PHMSA	NRC $50,000 Reporting Threshold	The requirement to report pipeline incidents estimated to exceed $50,000 to the National Response Center (NRC), within one hour is outdated and unnecessary. The requirement furthermore potentially distracts onsite personnel resources from their primary responsibility of maintaining a safe response to an incident. The $50,000 threshold was established in 1984 and, at a minimum, does not reflect an inflation adjusted current value of approximately $120,000. Additionally, many costs associated with pipeline operation have grown since 1984 at a rate faster than inflation. For instance, all but the most minor incidents will now incur cleanup costs greater than $50,000. These dynamics expand the practical effect of this reporting requirement far beyond its originally intended scope or level of severity. This has led to both pipeline operators, as well as the NRC, wastefully filing and processing incident reports that do not justify the cost, administrative burden or original policy intent. Another factor causing over-reporting is operators frequently are unable to calculate cleanup costs to determine whether the $50,000 threshold will be exceeded until days or weeks after the current one-hour reporting deadline. Also, equipment repair costs are not always readily available, even for small releases, until after repairs are complete. Many		Liquids Transmission Pipeline Operators	PHMSA should remove the NRC $50,000 reporting threshold in 49 CFR Part 195.52(a)(3), which would mitigate the financial-based requirement for a NRC call, reducing the time and effort the NRC and other government agencies spend to filter out and determine significant events. Furthermore, elimination of this outdated cost metric, which causes great efforts to estimate and calculate quickly, would allow operator personnel to ensure devotion of full attention to safety and environmental concerns during the response phase of an incident. API and AOPL support the remaining existing NRC reporting criteria for incidents involving fire, explosion, death or impact to water. Leaving these criteria in place while eliminating the dollar cost threshold will allow the NRC program to continue fulfilling its policy goal of alerting authorities and the public to significant pipeline incidents without a wasteful diversion of resources to low impact activities. Additionally, PHMSA should adjust its incident cost reporting requirement for property damage in 195.50(e) and 195.54 to at least current inflationary dollars, which would be approximately $120,000. Request that the instructions to Part A.4 be revised to include the phrase "*date/time an accident reporting criteria was met, not the date/time when the operator became aware of a potential failure or confirmed discovery of a reportable accident.*"

		considerations including; overtime, contractor costs and equipment replacement costs, can escalate during the actual project due to unforeseen difficulties. An example may be when a leaking valve is repaired but does not perform well, initiating a project to replace the valve. This will most likely cause costs to escalate past $50,000, for even a very minor release, that poses no safety or environmental concerns. This causes operators to file reports to avoid a late filing penalty for incidents which eventually do not reach the reporting threshold. Additionally, NRC practice is not to update previously filed reports to reflect new data, but to instead generate a new, additional incident report, causing further confusion on the incident. For these reasons, PHMSA should not merely adjust the $50,000 NRC reporting threshold for inflation, but instead should eliminate it entirely. An argument for at least updating the threshold figure can be made on the bases that PHMSA itself has updated penalty ranges and adjusts them with an index related to inflation. Part A.4 of PHMSA's Accident Reporting Form 7000-1 requires operators to identify the local time and date of an accident. The Form 7000-1 instructions state that operators must "[e]nter the local date/time an accident reporting criteria was met. In some cases, this date/time must be estimated based on information gathered during the investigation." With respect to the local time/date of an accident, both Form 7000-1 and its accompanying instructions are vague and uninstructive. The ambiguous nature of the instructions with respect to the item has led to confusion among operators attempting to accurately provide the local date/time of an accident. Additionally, PHMSA has disputed operator responses to A.4.			

Liquid Pipelines

EPA/PHMSA	EPA (40 CFR 112)/PHMSA (49 CFR 195) Facility Jurisdiction Boundaries	A 1971 DOT/EPA Memorandum of Understanding (MOU) established an understanding of the definition of transportation (DOT) versus non-transportation (EPA) related facilities. The definition of non-transportation related facilities in the 1971 MOU for oil storage facilities [definition (1)(F)] specifically excludes breakout storage tanks, and includes them as transportation related facilities (DOT jurisdiction) [definition (2)(C)]. Breakout tanks are storage tanks that lines deliver into where blending occurs. Then, the fluid may be further processed and eventually, moved within the facility or to a transmission line. These should be under PHMSA's jurisdiction since the product is pulled off a pipeline and then placed back on the line once blended, processed or stored for a period. However, a subsequent 2000 MOU sought to establish an understanding of what constitutes a complex facility, as well as the jurisdictional boundaries within complex facilities, so some breakout tanks are now considered in EPA jurisdiction, providing for current, inconsistent application of these MOUs between DOT and EPA Regions. There remains significant confusion and overlap between the DOT and EPA regarding facility response plans under Section 311 of the Clean Water Act and what agency has primacy in this matter. On Feb. 4, 2000, the EPA issued a letter to DOT clarifying jurisdictional distinctions between the two agencies. This letter provided examples of where the jurisdictional boundaries were drawn between EPA and DOT for the regulation of onshore pipeline facilities. The overlapping jurisdiction creates confusion among the regulated community. It can even create overlapping requirements for the same facility. For example, EPA and DOT have different methods for calculating worst case discharge and different plan content requirements. In addition, both		Midstream operators, specifically, those that have large storage facilities, considered to be complex by some regulators.	Agreement should be achieved between EPA and DOT on (1) what is considered a complex facility, and (2) how such a facility will be regulated and inspected. Two options to consider are (1) one agency regulates and inspects on behalf of both agencies, or (2) both agencies agree to oversee only their portion of the facility which would be identified on a facility site plan. For example, the pipeline that transports liquid and the breakout tanks that provide protection to those lines could be identified as PHMSA's jurisdiction. The valve on the opposite side of the breakout tank would end PHMSA jurisdiction, beginning EPA's oversight. DOT should update the applicability provisions to clearly indicate where the beginning and end points of each agency's jurisdiction are. In addition, the applicability provisions should also cross reference figures showing practical examples of complex facilities with the jurisdictional delineation for various equipment, including tanks, meters, and valves, to minimize potential confusion over which agency regulates which areas or pieces of equipment. This was attempted but not fully resolved in the February 4, 2000 MOU entitled "Jurisdiction Over Breakout Tanks/Breakout Storage Tanks (Containers) at Transportation-Related and Non-Transportation-Related Facilities." Currently, rule preambles and letters of interpretation often conflict with other PHMSA guidance documents. The following are examples: • Current internal PHMSA guidance indicates a valve would be the end point of jurisdiction within a terminal or refinery. However, there is long standing interpretation, based on rule preamble and numerous letters of interpretation, that state the fence-line of the refinery or terminal would be the demarcation if there was no pressure control device within the facility. • The same guidance indicates that any "pressure influencing device", such as a pump would be the beginning of jurisdiction from a pipeline origination point; however, previous interpretation stated the beginning of jurisdiction

		EPA and DOT require plan review and approval, however both have different processes.			would be ". . . something other than the pump itself, such as a pump control device or pressure relief valve" [PI-95-056].
PHMSA	Discovery of Condition Reporting and Mitigation	Currently, the regulations (195.452(h)(2)) provide that an operator has up to 180 days to obtain sufficient information after an integrity assessment to determine that a potential threat to the integrity of the pipeline exists. Unless the operator can demonstrate, the 180 day period is impractical.		Liquids Transmission Pipeline Operators	195.452 (h)(2) should provide for a more performance-based framework for responding to discovery of a condition. Including: 1. When running new technology tools, or integrating multiple tool runs to increase probability of detection/probability of identification (POD/POI), especially for cracks, there needs to be clearer provision to extending the discovery period in advance of the tool run as 180 days is impractical. One approach would be a provision to advance the re-inspection date to provide an equivalent extension to the discovery timeline. Following this approach, the calendar date when discovery is required is essentially unchanged from the original ILI due date plus 180 days. 2. Where reruns are required, use of the partial data set pending a successful re-run should be limited to only the discovery of immediate features. The regulatory text should be modified as shown below, with the changes differentiated in **<u>red, bold, and underlined</u>**, to capture this performance-based approach that encourages innovation: §195.452 (h) … (2) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable. **<u>Operators should identify and document in advance potential additional analysis time required to analyze and integrate results and apply a shorter assessment interval such that any necessary increase in the 180-day determination period is offset by an equivalent reduction in the assessment interval.</u>**
PHMSA	Audit Protocols, Coordination, and Jurisdiction	Coordination should exist between PHMSA and other Federal/State regulators to reduce inefficiencies, redundancies, increased costs, longer durations, as well as a resource drain associated with managing and responding to audits by multiple agencies. As an		All operators that are currently have OPIDs and have	Better coordination between government agencies to ensure duplicative actions are conducted simultaneously could improve efficiencies in both private and public organizations.

		example, audits currently last an average of 6-10 weeks. Also, for instance, Control Room Audits have to be conducted by both PHMSA and the overseeing state agencies, but very often, these audits are conducted independently, and the agencies do not coordinate with each other. Operators know Control Room Management is critically important to meeting the industry's goals of zero leaks and zero incidents, but these rules were written, with a significant focus on documentation, which is needed to comply with the numerous audits. Unfortunately, this causes operators to expend a disproportionate amount of effort and resources to pass PHMSA inspections versus focusing on improving operator performance and pipeline safety. Finally, and similarly, Emergency Response Plan Reviews are required by PHMSA and EPA, but these, too are completed independently and uncoordinated. As currently written, FAQs and Enforcement Guidance can be interpreted to add requirements not existing in regulation or in industry standards referenced in regulation. Finally, the activities occurring after an inspection need to be reviewed. PHMSA may send formal "Letters of Concern" that do not cite any regulatory violation or non-conformance. This process does not follow normal auditing protocols other federal, state or local regulatory bodies use. Communication following a PHMSA inspection should also be addressed. An Operator waits a significant amount of time following a PHMSA inspection before they receive a probable violation notice or warning letter. Regulatory certainty cannot be achieved during this "waiting period."		assets located in multiple PHMSA regions.	Additionally, amend the audit program to encourage all auditors utilize documentation and records from previously completed audits. Update Control Room Management regulations, which will improve the audit process, to focus on improving operator performance and relieve the administrative burden on pipeline operators of over documentation. When inspection protocols use FAQs or Enforcement Guidance, PHMSA inspectors issue inspection results as "Satisfactory" vs "Unsatisfactory" based on elements that are not even enforceable, as these documents are not regulations and do not have the force of law. This leads to wasted use of resources for both the operator and PHMSA as an excessive amount of time is spent evaluating if the issue was truly a non-compliant with regulations. PHMSA should no longer send "Letters of Concern" that do not cite a regulatory non-conformance. PHMSA communication timing should be appropriate, taking into account the time to adequately address any issue that may arise.
PHMSA	PHMSA Requests for Information (RFIs)	In March, PHMSA promulgated a new regulation (190.343) specifically addressing how to submit confidential information to PHMSA. The requirement is that an unredacted copy of confidential information be provided (marked "confidential") along with a redacted version and an explanation of why the			PHMSA should narrowly tailor information requests and should require the filing of confidential information only when essential. If confidential information is requested in contexts such as an audit, investigation, or review of a construction project, then PHMSA should review confidential information through a secure format and then

		information is considered confidential. While these procedures are generally appropriate for the submittal of documents in a rulemaking or special permit context, these procedures apply even when voluminous documents are requested, such as an agency audit, investigation and review of construction projects. The process of redacting information from voluminous documents is very burdensome and costly, and if a Freedom of Information Act (FOIA) request is not made for the documents, then dedicating significant resources to such an effort is unwarranted. A more streamlined approach, that provides PHMSA with necessary documents without imposing undue burdens, should be employed. In addition, the wording of section 190.343 focuses on confidential "commercial" information, but it should apply to all confidential information that is exempt from disclosure under FOIA. Parties often submit information exempt from public disclosure under other FOIA exemptions, such as security sensitive information, information specifically exempted by other statutes, and personal privacy information, and PHMSA should ensure that its procedures protect the disclosure of all confidential information. Section 190.343 should be modified accordingly.			request the filing of the original version of documents that it requires. The submitting party shall identify any such documents that contain confidential information, and if a Freedom of Information Act (FOIA) request is made, then for documents that contain confidential information, a second copy of the original document, with the confidential information deleted, should be provided to PHMSA within a reasonable period of time, and such redacted documents would be provided in response to the request. In addition, PHMSA should revise section 190.343 to delete all references to "commercial," to reflect the fact that the regulation applies to the treatment of all confidential information. PHMSA should revise its regulations in Part 190 to implement the following clarification to 190.343. The changes are differentiated in **red, bold, and underlined** below: §190.343 Information made available to the public and request for protection of confidential ~~commercial~~ information. (a) *Asking for protection of confidential* ~~commercial~~ *information.* You may ask us to give confidential treatment to information you give to the agency by taking the following steps: … (2) ~~Send us, along with the original document, a second copy of the original document with the confidential commercial information deleted.~~ **Send us the original document. Send a second copy of the original document with the confidential information deleted (i) along with the original document during a rulemaking proceeding and for special permit or renewal applications and (ii) for information submitted for any other reason, within a reasonable time following notification by PHMSA that it has received a Freedom of Information Act request for such information.** (3) Explain why the information you are submitting is confidential ~~commercial~~ information. (b) *PHMSA decision.* PHMSA will treat as confidential the information that you submitted in accordance with this section, unless we notify you otherwise. If PHMSA decides to disclose the information, PHMSA will review your request to protect confidential ~~commercial~~ information…
PHMSA	Pipeline Status Definitions	PHMSA regulations only provide for two pipeline statuses, active and abandoned, but there are varying states that industry would like to have to designate		Liquids Transmission	Consider incorporation of the industry's consensus document on the different states of pipelines, which is currently under development. The intent and scope will provide guidance for determining the status

		pipelines. In fact, PHMSA's NPMS has more than just active and abandoned as options to classify pipelines.		Pipeline Operators	of a pipeline. It also provides the risk-based framework for pipeline maintenance and guidance on managing assets throughout their lifecycle. At a minimum, the regulations should align with the guidance associated with PHMSA's NPMS.
PHMSA	49 CFR 195.49 Annual Report Clarifications	PHMSA reporting requirements remain unclear in several places. Additionally, the length of time between updates to reporting instructions prevents timely correction of program problems.		All operators that currently have OPIDs and are required to report under this part	The following recommendations are offered: A. Clearly defined instructions on information that is being requested and is required. Require reporting instructions to be updated every two years. B. Hydrotesting criteria should be broken down into seam vs regulatory base for clarification. C. Allow an operator to report ALL mileage in an HCA; then break that mileage down by type. Then define other segment miles as "could affect." D. Add idle and abandon pipeline to the reporting. This would then make question Part F (6)(e) relevant. If not adding abandoned mileage to the report, then remove question Part F (6)(e). E. Expand the types of tool runs to current industry standards. F. Define the reporting criteria for Hydrotest G. Delete sections A6 and A8 since PHMSA has already removed both of these sections from the report.
PHMSA	Appropriate Valve Integrity Testing	Section 195.116 on valves states that each valve installed in a pipeline system must comply with the following: (d) Each valve must be both hydrostatically shell tested and hydrostatically seat tested without leakage to at least the requirements set forth in Section 11 of ANSI/API Spec 6D (incorporated by reference, see §195.3).		Liquids and Gas Pipeline Operators	Recommendation to seek clarification regarding 6D requirements. Operators would like to have further definition regarding valve applications for which 6D applies, specifically a minimum diameter size. Other traceable quality control checks should also be added. Currently, over compliance wastes resources in the absence of better clarity.
PHMSA	Proper Pipeline Component Examining	Current regulatory text needing to be revised is given below: (a) Each pressure test under §195.302 must test all pipe and attached fittings, including components, unless otherwise permitted by paragraph (b) of this section. (b) A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either—		Liquids Pipeline Operators	Recommendation to consider all tests from the factory/manufacturer rather than just one component.

		(1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.			
PHMSA	Integrity Management Program Improvements	It was detailed earlier in the comments on the proposed rulemaking, but to reiterate, as it is in current regulation as a 180-day repair condition, the repair criteria "corrosion of or along a longitudinal seam weld" is not adequate. No appropriate integrity management can be executed if strict application of this is required by the regulator. The workable solution proposed by API in previous communications with PHMSA would remedy this issue. In Appendix C to 49 CFR Part 195 – Guidance for Implementation of an Integrity Management Program, the following provisions are given: 1. I B. (3) Crossing of farm tile fields. An operator should consider the possibility of a spillage in the field following the drain tile into a waterway 2. I B. (6) Physical support of the pipeline segment such as by a cable suspension bridge. An operator should look for stress indicators on the pipeline (strained supports, inadequate support at towers), atmospheric corrosion, vandalism, and other obvious signs of improper maintenance. 3. I B. (7) Operating conditions of the pipeline (pressure, flow rate, etc.). Exposure of the pipeline to an operating pressure exceeding the established maximum operating pressure. 4. I B. (12) Potential natural forces inherent in the area (flood ones, earthquakes, subsidence areas).		Liquids Transmission Pipeline Operators	If the feedback already given to the Agency is not taken, then the current 180-day condition to remediate "corrosion of or along a longitudinal seam weld" must be changed. The following text would adequately address the concern, with the changes differentiated in **red, bold, and underlined**: §195.452 (h)(4)(iii) … (H) Corrosion of or along a longitudinal seam weld **unless an engineering analysis is performed, with verifiable field testing, to determine specifically ordinary corrosion crossing the long seam, which poses minimal risk to pipeline integrity.** 1. Drainage tiles are unmapped features that cannot be located using Digital Elevation Models (DEM) or the National Hydrography Dataset (NHD). These features can only be determined through consultation with individual land owners and, as these features have often not been surveyed, there is no efficient way to accurately map their location. Additionally, drainage tiles may be removed or relocated frequently making the dataset difficult to maintain the time required to collect and maintain this data set is burdensome. Remove the requirement to consider drainage tile and instead rely exclusively on the digital elevation model and stream network to determine overland flow and stream trajectory. 2. It is unclear why this guidance is provided in relation to identifying high consequence areas. The examples identified appear to be threats to the pipeline as opposed to consequences. Remove statement from the regulation or move to a more applicable section of the regulation. 3. It is unclear why this guidance is provided in relation to identifying high consequence areas. Overpressure is considered a threat to the pipeline, not a consequence. Remove statement from the regulation or move to a more applicable section of the regulation 4. It is unclear why this guidance is provided in relation to identifying high consequence areas. The examples identified appear to be threats to the pipeline as opposed to consequences. Remove

					statement from the regulation or move to a more applicable section of the regulation.
PHMSA	Risk-Based Alternative to Pressure Testing Older Hazardous Liquid and Carbon Dioxide Pipelines (49 C.F.R. Part 195.303)	PHMSA should consider revising 49 C.F.R. Part 195.303 to expand the ability of operators to rely on alternative risk based testing where Subpart E pressure test records may not exist (regardless of whether a pipeline was constructed before 1970 or not). Part 195.303 outlines a one-time option to use risk based alternatives to pressure testing older pipelines, for which the deadline has passed. That deadline should be removed. As outlined under Part 195.303(f), operators electing to follow a program for testing a pipeline on risk-based criteria as an alternative to pressure testing "must develop plans that include the method of testing and a schedule for the testing by December 7, 1998." The provision goes on to list test deadlines by certain dates that have long since passed in 2002 and 2004.		Liquids Transmission Pipeline Operators	This provision should be revised to allow all pipelines to implement alternative testing where all of the required Subpart E pressure test records under Part 195 may not exist. In addition, the provision under 195.303(d) regarding pre-1970 ERW pipe should be repealed because the susceptibility of pre-1970 ERW pipe is already adequately addressed under PHMSA IMP regulations at 195.452. This could easily be done by deleting, 49 C.F.R. Part 195.303(f) and making relevant revisions to Part 195.303(a) and Part 195, Appendix B. Otherwise pressure testing pipelines where indicia of a prior valid pressure test already exists is a burden on operators and a waste of valuable resources.
PHMSA	Traceable, Verifiable and Complete Maximum Operating Pressure (MOP) Records Standard	In response to NTSB Recommendations and the 2012 amendments to the Pipeline Safety Act, PHMSA issued advisory guidance to operators to ensure that the MAOP and MOP of *all* liquid and gas pipeline segments are supported by records that are "traceable, verifiable and complete." While acknowledging that "other types of records may be acceptable and that certain state programs may have additional requirements," PHMSA provides limited additional guidance with regard to the meaning of the terms "traceable," "verifiable" and "complete."		Liquids Transmission Pipeline Operators	The guidance should be revised to be consistent with Federal Rules of Evidence and the best evidence rule by allowing for the submission of affidavits and/or other records supporting that original tests were completed in compliance with the regulations. Another option would be to allow for similar language that was recently presented to the Gas Pipeline Advisory Committee during their proceedings on *Safety of Gas Transmission and Gathering Pipelines* NPRM, which is based on the advisory: *Traceable, verifiable, and complete means that a single record or a combination of records:* *(1) can be linked to original information about a pipeline segment or facility and is finalized as evidenced by a signature, date, or other appropriate marking or* *(2) has other similar characteristics that support its validity.* *A single record can be traceable, verifiable, and complete. However, in some situations, complementary, but separate, documentation may be necessary. In determining whether a record is traceable, verifiable, and complete, due consideration shall be given to the standards and practices in effect at the time the record was created.*