Comments by Issue

Issue ID 1.1 Reporting requirements for gravity lines

Subissue: General agreement

Commenter: St Croix River Association (SCRA)

This proposal would add reporting requirements that are currently applicable to transmission lines to gravity fed lines as well as about 40,000 miles of gathering lines. We support the requirements for submission of annual reports, incident reports, and safety related condition reports on these additional lines.

Supports PHMSA proposal.

Subissue: Implementation schedule

Commenter: American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)

API and AOPL respectfully request that PHMSA extend the proposed implementation period to one year after the effective date of the final rule. As these lines were not previously regulated, operators will need to undertake a review of voluminous documents, dating back decades in some instances, in order to compile historical data. The additional time will provide operators with an opportunity to collect the necessary information and integrate the new information into their existing practices for information collection and reporting to be responsive to the proposed requirement. [p.4]

Extend the implementation period [1 year]

Commenter: Enterprise Products Partners

Enterprise requests that PHMSA include a ten (10) year baseline period for operators to comply with these reporting requirements in order to prevent the misdirection of limited resources.

Requests that PHMSA include a ten year baseline period for operators to comply with reporting requirements for gravity lines.

Subissue: Reporting format

Commenter: American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)

API and AOPL also recommend that PHMSA create a new abbreviated annual report with input from operators to segregate the reporting of pipeline data for regulated pipelines and those not currently subject to 49 C.F.R. §195. [p.3]

The report form would also relieve any unnecessary burdens that would potentially be placed on operators by reporting information that is not pertinent to gravity lines. [p.3]

Recommend development of new abbreviated form specific to the requirements applicable to gravity lines

Commenter: Energy Transfer Partners

In all cases, for reported gravity lines and previously not reported gathering lines, a much more limited set of data may be all that is available. ETP suggests that PHMSA either develop shorter reporting forms, or modify existing forms to essentially “gray out” as not required those fields that are much less applicable to these lines.

Recommend development of new abbreviated form specific to the requirements applicable to gravity lines

Commenter: Gas Processors Association

At least three GPA members have responded expressing concern with the ability to gather all of the data required to comply with the data collection effort as proposed without extensive resource commitment. All would involve piping at tank farms.
The majority of GPA responding members support the data collection efforts with essentially the same comments and concerns expressed above for gathering lines. We recommend an abbreviated form as described above for this purpose as well.

Recommend development of new abbreviated form specific to the requirements applicable to gravity lines

Subissue **Scope of applicability**

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

API and AOPL recognize that certain gravity lines are longer, and do not oppose data collection for these lines to assess the safety performance and risk of these lines, but request that PHMSA not impose the proposed reporting requirement on more limited gravity lines. Therefore, API and AOPL propose that the data collection be narrowed, such that it would apply only to those gravity lines that: 1) travel outside of facility boundaries for at least one mile; 2) operate at a specified minimum yield strength level of twenty percent or greater; and 3) are not otherwise exempted in Section 195.1(b). [p.3]

API and AOPL oppose the inclusion of intra-facility and tank farm gravity lines in the proposed regulation because these lines generally exist wholly inside facility boundaries or move product between facilities within close proximity. Containment features, such as berms, limit the ability of a facility release to impact the public or the environment. Moreover, these lines operate at a very low pressure. [p.3]

Exempt from reporting requirements gravity lines with relatively lower risk [Don't travel outside facility boundaries for at least 1 mile; operate at yield strenghth level less than 20%; or are otherwise exempted in Section 195.1(b))]

Commenter **Denbury Resources**

C02 pipelines are a distinct class of pipelines and have historically had a good safety record. Under 49 CFR 195.50, pipeline operators, including CO2 pipeline operators, are required to report accidents to the Department of Transportation. Since reporting began in the early 1990s, the federal database demonstrates that CO2 pipelines have had a "particularly good" safety record.

Exempt from reporting requirements gravity lines with relatively lower risk [Exempt CO2 pipelines]

Commenter **Energy Transfer Partners**

In these sections, PHMSA proposes to extend annual, accident and safety-related condition reporting requirements to any gathering line not already covered [§195.1(a)(5)] and to pipelines transporting hazardous liquids by gravity [§195.13(b)]. ETP understands PHMSA's desire to collect such information more broadly than is presently done. ETP would like to emphasize a few points. First, many, if not most gravity lines are short and are contained within a facility controlled by the operator. These pose little risk, and gathering such information on them is seen to be of little value. For gravity lines, the reporting requirements should be limited to those meeting certain criteria that imply some public interest, such as crossing a waterway or public right-of-way.

Exempt from reporting requirements gravity lines with relatively lower risk [Limit requirements to lines of public interest such as crossing waterway or public right-of-way]

Commenter **International Liquid Terminals Association**

In its notice, PHMSA has proposed to extend certain annual, safety-related, and incident reporting requirements to all gravity lines. ILTA proposes that such new requirements be limited only to those gravity lines that (1) travel outside of facility boundaries for at least one mile; (2) operate at a specified minimum yield strength level of twenty percent or greater; and (3) are not otherwise exempted in 49 CFR 195.1(b). ILTA opposes any inclusion of intra-facility or tank farm lines in the proposed regulation. These lines generally exist wholly inside facility boundaries or move product between facilities within close proximity of one another. These lines operate at very low pressure and pose de minimus risk to either the public or the environment. These lines do not merit inclusion within the proposed new requirements.

Exempt from reporting requirements gravity lines with relatively lower risk [Don't travel outside facility boundaries for at least 1 mile; operate at yield strenghth level less than 20%; or are otherwise exempted in Section 195.1(b))]

Commenter **Pipeline Safety Coalition**

PSC strongly supports the intent of Proposal 1 to extend reporting requirements to all gravity fed and gathering line
hazardous liquids lines. We would add our recommendation, as submitted to the PA PITF, that all pipelines be
jurisdictional to PHMSA, the state Utility Commission, and that they be required to register with the Commission. The
exemption of gravity and gathering lines from PHMSA regulations has long been a concern for PSC, the Pennsylvania
Public Utility Commission (PA PUC) and PA One Call professionals who have sought for all pipelines be jurisdictional
and GIS mapped.

Broaden PHMSA requirements to all pipelines and require registration with state Utility Commission

Commenter **Texas Pipeline Association**

Rather than imposing reporting obligations on all gravity lines, TPA recommends that PHMSA only subject hazardous liquid gravity pipelines that extend beyond an operator controlled site by more than a de minimus distance to these new reporting requirements.

Exempt from reporting requirements gravity lines with relatively lower risk [Extend beyond operator site by more than de minimus distance]

Subissue **Scope of requirements**

Commenter **Accufacts**

In order to truly gauge a company's IM program and performance, PHMSA needs to present regulatory mandated IM pipeline repairs by:
1) pipeline system,
2) state,
3) whether in an HCA or not,
4) the assessment method(s) utilized,
5) regulated scheduled repair timing category, and
6) by cause.
This simple performance metric information can be collected via pipeline operator Annual Reports to PHMSA and will permit pipeline operators and regulators to quickly and efficiently ascertain whether pipeline operator risk management decisions and various IM assessment approaches/options are complete, prudent, and effective. Such metrics also help to identify possible systemic problems that need to be further addressed. I am well aware of past efforts by some pipeline companies to avoid reporting such important performance metrics such as by state, but if companies do not have such information already available, serious challenges and questions should be raised about their IM approaches.

Broaden requirements [Require additional reporting of information and organization in the Annual Report]

Commenter **Alliance for Great Lakes et al.**

PHMSA should also put forward minimum standards for these lines to ensure that they are actually subject to PHMSA regulation. Approximately 90 percent of onshore gathering line mileage does not have to adhere to minimum federal standards on pipeline safety – less than 4,000 miles of the estimated 30,000 to 40,000 miles of onshore hazardous
liquid gathering lines are subject to PHMSA regulation.

Broaden requirements [Require minimum safety standards]

However, in order to "effectively analyze safety performance and pipeline risk of gathering lines," which was PHMSA's stated purpose in expanding the reporting requirements,43 PHMSA should require GIS mapping information.

Broaden requirements [Require GIS mapping information]

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

Reporting requirements for gravity lines should be more specific on the exact provisions that would apply to these lines (i.e., specific reference to Sections 195.48-195.56 and 195.58(a)-195.58(d)), and exclude provisions for pipeline mapping system. [p.2]

Clarify and tailor the reporting requirements

Commenter **Dakota Rural Action**	
While we support this requirement, we urge PHMSA to also require pipeline operators to provide GIS mapping information and minimum safety standards for all pipelines. States often do not require companies to provide a GIS map of smaller gathering lines, and many states have hundreds of unmapped pipelines, which is a safety issue. It is important to require minimum safety standards for all pipelines because many states do not have minimum requirements for the construction of gathering lines.	*Broaden requirements [Require GIS mapping information]*
Commenter **Energy Transfer Partners**	
Finally, ETP suggests that some of the criteria for a safety-related condition cannot be determined because the external features, such as proximity to certain structures, have not been required data and may not be available to the operator. Thus it would be reasonable to eliminate this safety-related condition reporting requirement, or recognize the amount of data an operator would have to collect in conjunction with such a requirement, include such data collection in the regulatory analysis, and provide sufficient implementation time.	*Narrow requirements [Eliminate safety-related condition reporting requirement or include it in regulatory analysis and implementation timeframe]*
Commenter **Environmental Defense Center**	
Complete data should be required regarding the location, operation, condition and history of these lines.	*Broaden requirements [Include location, operation, condition, and history in reporting]*
Commenter **Gas Processors Association**	
At least three GPA members have responded expressing concern with the ability to gather all of the data required to comply with the data collection effort as proposed without extensive resource commitment. All would involve piping at tank farms. The majority of GPA responding members support the data collection efforts with essentially the same comments and concerns expressed above for gathering lines. We recommend an abbreviated form as described above for this purpose as well.	*Clarify and tailor the reporting requirements*
Commenter **Janet Alderton**	
I conclude that the First and Second Proposals are not only unnecessary, but may aggregate data that are inaccurate or misleading.	*Reporting requirements are unneccesary and may be innaccurate or misleading*
Commenter **Judy Skog**	
I applaud your inclusion of all hazardous liquids lines in the reporting. I urge you to require GIS mapping coordinates in that reporting.	*Broaden requirements [Require GIS mapping information]*
Commenter **Kathy Hollander**	
Minimum safety standards should be set for these lines as well.	*Broaden requirements [Require minimum safety standards]*
GIS mapping information should be required for gravity fed and gathering pipelines	*Broaden requirements [Require GIS mapping information]*
Commenter **League of Women Voters of California**	
The annual reporting requirement for gravity fed and gathering lines that is included in the proposed rule for pipelines under your jurisdiction is a positive step. However, mapping information and minimum safety standards are essential for these pipelines as well, and should be added to your requirements.	*Broaden requirements [Require GIS mapping information]*

Inspection reports, notices of violation, and similar documents should be readily available to the public.	*Require inspection reports, notices of violation, and similar documents to be made available to the public*
The annual reporting requirement for gravity fed and gathering lines that is included in the proposed rule for pipelines under your jurisdiction is a positive step. However, mapping information and minimum safety standards are essential for these pipelines as well, and should be added to your requirements.	*Broaden requirements [Require minimum safety standards]*

Commenter **Pipeline Safety Coalition**

PSC is pleased with the initial extension of reporting data by adding 49 CFR 195.1(a)(5) to require that the operators of all gravity and gathering lines comply with requirements for submitting annual, safety-related condition, and incident reports and strongly recommends incorporating requirements that all pipelines, regardless of location, become jurisdictional and provide GIS mapping coordinates.	*Broaden requirements [Require GIS mapping information]*
PSC suggests that minimum safety standards be added to the rules/standards as non-HCA HL pipelines, we suggest the final rule require these lines to meet minimum pipeline safety standards.	*Broaden requirements [Require minimum safety standards]*

Commenter **Pipeline Safety Trust**

Given the relatively small cost of subjecting them to the same standards as non-HCA HL pipelines, we suggest the final rule require these lines to meet minimum pipeline safety standards	*Broaden requirements [Require minimum safety standards]*
We would like to see this reporting extended to require submissions to NPMS for geographic information system mapping purposes.	*Broaden requirements [Require GIS mapping information and submission of GIS information to NPMS]*

Commenter **St Croix River Association (SCRA)**

the proposed rules do not require GIS mapping information or any minimum safety standards for the lines that will be covered under this expansion.	*Broaden requirements [Require GIS mapping information]*
the proposed rules do not require GIS mapping information or any minimum safety standards for the lines that will be covered under this expansion.	*Broaden requirements [Require minimum safety standards]*

Commenter **State of Washington Citizens Advisory Committee on Pipeline Safety**

Washington does not have any gravity or gathering lines in the state. In the interest of national pipeline safety, the Committee supports the reporting requirement recommendation for gravity and gathering lines contained in the NPRM. We also ask that these lines be brought under basic safety regulations as soon as possible.	*Broaden requirements [Require minimum safety standards]*

Commenter **Texas Pipeline Association**

In order to facilitate the limited reporting contemplated by this rulemaking, TPA also recommends that PHMSA adjust the instructions for annual and incident reports to limit the information reported by gravity pipeline operators to relevant data elements and to readily available information	*Clarify and tailor the reporting requirements*
reporting required for certain gravity pipelines be limited to annual and incident reports . . . And that safety-related condition reports not be required at this time because many of the situations triggering safety-related condition reporting are tied to issues of compliance with safety regulations. At this time, there are no safety regulations applicable to gravity hazardous liquid pipelines, so there would be nothing to trigger a safety-related report from such pipelines.	*Narrow requirements [Eliminate safety-related condition reporting requirement and limit reporting to annual and incident reports]*

Commenter **Tip of the Mitt Watershed Council**

In addition to reporting requirements, we believe that these pipelines should also be subject to the minimum federal pipeline safety standards.

Broaden requirements [Require minimum safety standards]

Commenter **Western Organization of Resource Councils**

Although we support this enhanced requirement, we urge PHMSA to also require pipeline operators to provide GIS mapping information and to meet minimum safety standards for all pipelines. States often do not require companies to provide a GIS map of smaller gathering lines, and many states have hundreds of unmapped pipelines, extending thousands of miles and presenting many safety issues. It is important to require minimum safety standards for all pipelines including gathering lines unregulated by the states.

Broaden requirements [Require GIS mapping information]

Issue ID **1.2** **Reporting requirements for rural gathering lines**

Subissue **Costs**

Commenter **Gas Processors Association**

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

Need to better account for burden [Even gathering line operators currently submitting annual reports will be impacted by the rule and face increased reporting costs for the pipeline that is currently not regulated]

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

Need to better account for burden [Sec. 195.61 and 195.64 should not be included in the data collection effort, or if included, the burden of providing this information should be included in the RIA.]

While the data and cost associated with the actual filing of the report are included in the analysis, GPA feels PHMSA has neglected to account for the costs and burden associated with the initial compiling of the data needed to complete the forms. In many cases, the information may not be recorded or may not have been provided during mergers or acquisitions. PHMSA has not communicated its expectations for these situations. GPA requests that PHMSA clarify their expectations regarding the specific pipe details. If it is PHMSA's expectation that operators physically excavate to obtain the data, the costs will reach into the hundreds of millions.

Clarify and tailor the reporting requirement [Request for clarification of expectations for the specific pipe details for gathering lines in the report; if new data will be collected, PHMSA needs to account for that in its cost estimates.]

Commenter **Louisiana Mid-Continent Oil and Gas Association (LMOGA)**

The other non-emergency reporting requirements will impose significant burdens on companies. This is especially true in the current business economic climate. Due to the current commodity pricing climate (which is expected to exist for several years), individual wells are being bought and sold, and shut in on a routine basis. Operating companies are also experiencing bankruptcies. At a time when companies are striving to cut costs, PHMSA proposes a rule with significant economic burdens on these companies.	*Need to better account for burden [Non-emergency reporting requirements impose a significant burden. The rule should not expanded to gathering lines until this issue is addressed.]*
Again, according to the Office of Conservation, simply adding gathering lines to the rules will double the amount of their potential workload (assuming they seek primacy of these rules). There is also the workload of the new proposed rules on existing regulated lines. This is a tremendous potential increase in the workload of the agency. In Louisiana, agency funding and manpower levels are set by the Legislature. The agency has no authority to self-determine its resources and how to obtain them (except for dedicated federal funding). As Louisiana is in a Gubernatorial/Legislative transition (effective January 1 1, 20 16), LMOGA has no idea what the sentiment of the new government would be to funding this program. Even if industry supported funding and manpower increases for the agency, there is no guarantee the government will support.	*Need to better account for burden [Reporting requirements would overly burden the LA Office of Conservation. The rule should not expanded to gathering lines until this issue is addressed.]*

Subissue **General agreement**

Commenter **St Croix River Association (SCRA)**

This proposal would add reporting requirements that are currently applicable to transmission lines to gravity fed lines as well as about 40,000 miles of gathering lines. We support the requirements for submission of annual reports, incident reports, and safety related condition reports on these additional lines.	*Supports PHMSA proposal*

Subissue **Implementation schedule**

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

API and AOPL respectfully request that PHMSA extend the proposed implementation period to one year after the effective date of the final rule. [p.5]	*Extend implementation perio [1 year]*

Commenter **Enterprise Products Partners**

Enterprise requests that PHMSA include a ten (10) year baseline period for operators to comply with these reporting requirements in order to prevent the misdirection of limited resources.	*Extend implementation peri [Requests that PHMSA include a ten year baseline period for operators to comply with reporting requirements for gathering lines.]*

Subissue **Reporting format**

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

The Associations recommend that PHMSA create a new abbreviated accident report form for those pipelines not currently subject 49 C.F.R. 195 that requests operators to report only that information relevant to those pipelines. [p.4]	*Recommend development of new abbreviated form specific to the requirements applicable to rural gathering lines*

Commenter **Energy Transfer Partners**

In all cases, for reported gravity lines and previously not reported gathering lines, a much more limited set of data may be all that is available. ETP suggests that PHMSA either develop shorter reporting forms, or modify existing forms to essentially “gray out” as not required those fields that are much less applicable to these lines.

Recommend development of new abbreviated form specific to the requirements applicable to rural gathering lines

Commenter **Gas Processors Association**

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

Recommend development of new abbreviated form specific to the requirements applicable to rural gathering lines [and opposes telephonic notice]

Subissue **Scope of applicability**

Commenter **American Gas Association (AGA)**

AGA does not support the proposed regulatory requirement to report information and data on all hazardous liquid gathering lines, 80 Fed. Reg. 61611, that are outside of PHMSA’s current substantive regulatory requirements. AGA agrees with API & AOPL’s comments on this topic. Similar to nonregulated hazardous liquid pipelines, gas gathering lines located in Class 1 locations are not regulated by PHMSA. Data associated with regulatory requirements such as Operator Qualification and Control Room Management should not be required to be reported for pipelines that are exempt from those regulatory programs. PHMSA should specifically evaluate the elements within the Safety Related Condition Report to determine which elements should be excluded for unregulated liquid, or gas, gathering pipelines. AGA does support PHMSA requesting that operators submit all available information; however, AGA believes the data points that are not applicable to the pipeline should not be a regulatory reporting requirement.

Clarify and tailor the reporting requiremen [Information and data on gathering lines not currently associated with regulatory requirements applicable to these pipelines should not be required]

Commenter **Denbury Resources**

C02 pipelines are a distinct class of pipelines and have historically had a good safety record. Under 49 CFR 195.50, pipeline operators, including CO2 pipeline operators, are required to report accidents to the Department of Transportation. Since reporting began in the early 1990s, the federal database demonstrates that CO2 pipelines have had a "particularly good" safety record.

Exempt from reporting requirements gathering lines with relatively lower risk [Exempt CO2 pipelines]

Commenter **Independent Petroleum Association of America**

The Proposed Rules seek to mandate reporting to PHMSA for all hazardous liquids pipelines whether jurisdictional or non-jurisdictional. As set out in 49 C.F.R. Part 195, PHMSA is “proposing to add § 195.1(a)(5) to require that operators of all gathering lines (whether onshore, offshore, regulated, or unregulated) comply with requirements for submitting annual, safety-related condition, and incident reports.”5 This would require that owners of all gathering lines, whether onshore, offshore, regulated or not, comply with requirements for submitting annual, safety-related condition, and incident reports. [Arguments are provided in the comment]

This requirement exceeds PHMSA's statutory authority

Commenter **Offshore Operators Committee**

Finally, in regards to rural gathering lines, the OOC is concerned by the extent to which this requirement will apply. There are gathering lines offshore within state waters that are currently not regulated by PHSMA or BSEE and there are other gathering lines that are regulated by BSEE. The OOC requests that PHMSA make clear in their final rule that this intent is to not have these proposed requirements apply to either of these types of lines.

Narrow applicability [Clarify that lines offshore within state waters and lines regulated by BSEE are not included in this rule]

Commenter **Pipeline Safety Coalition**

PSC strongly supports the intent of Proposal 1 to extend reporting requirements to all gravity fed and gathering line
hazardous liquids lines. We would add our recommendation, as submitted to the PA PITF, that all pipelines be
jurisdictional to PHMSA, the state Utility Commission, and that they be required to register with the Commission. The
exemption of gravity and gathering lines from PHMSA regulations has long been a concern for PSC, the Pennsylvania
Public Utility Commission (PA PUC) and PA One Call professionals who have sought for all pipelines be jurisdictional
and GIS mapped.

Broaden PHMSA requirements to all pipelines and require registration with state Utility Commission

Subissue **Scope of requirements**

Commenter **Accufacts**

In order to truly gauge a company's IM program and performance, PHMSA needs to present regulatory mandated IM pipeline repairs by:
1) pipeline system,
2) state,
3) whether in an HCA or not,
4) the assessment method(s) utilized,
5) regulated scheduled repair timing category, and
6) by cause.
This simple performance metric information can be collected via pipeline operator Annual Reports to PHMSA and will permit pipeline operators and regulators to quickly and efficiently ascertain whether pipeline operator risk management decisions and various IM assessment approaches/options are complete, prudent, and effective. Such metrics also help to identify possible systemic problems that need to be further addressed. I am well aware of past efforts by some pipeline companies to avoid reporting such important performance metrics such as by state, but if companies do not have such information already available, serious challenges and questions should be raised about their IM approaches.

Broaden requirements [Require additional reporting of information and organization in the Annual Report]

Commenter **Alliance for Great Lakes et al.**

However, in order to "effectively analyze safety performance and pipeline risk of gathering lines," which was PHMSA's stated purpose in expanding the reporting requirements,43 PHMSA should require GIS mapping information.

Broaden requirements [Require GIS mapping information]

PHMSA should also put forward minimum standards for these lines to ensure that they are actually subject to PHMSA regulation. Approximately 90 percent of onshore gathering line mileage does not have to adhere to minimum federal standards on pipeline safety – less than 4,000 miles of the estimated 30,000 to 40,000 miles of onshore hazardous
liquid gathering lines are subject to PHMSA regulation.

Broaden requirements [Require minimum safety standards]

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

While the Associations appreciate the reference to Subpart B in the regulatory text, API and AOPL propose PHMSA use the following language, with new language indicated in bold, in the final rule at Section 195.1(a)(5): "For purposes of the reporting requirements in subpart B of this part, any gathering lines not already covered under paragraphs (a)(1), (2), (3), or (4) of this section comply with the reporting requirements of Subpart B, Sections 195.48 through 195.56 and 195.58(a) – 195.58(d)." The suggested language is fully consistent with the statement made in the webinar that National Pipeline Mapping System reporting under Section 195.61 would not be required for gathering lines. [p.4]	*Clarify and tailor the reporting requirements[Suggests language]*
Commenter **Dakota Rural Action**	
While we support this requirement, we urge PHMSA to also require pipeline operators to provide GIS mapping information and minimum safety standards for all pipelines. States often do not require companies to provide a GIS map of smaller gathering lines, and many states have hundreds of unmapped pipelines, which is a safety issue. It is important to require minimum safety standards for all pipelines because many states do not have minimum requirements for the construction of gathering lines.	*Broaden requirements [Require GIS mapping information]*
Commenter **Environmental Defense Center**	
Complete data should be required regarding the location, operation, condition and history of these lines.	*Broaden requirements [Include location, operation, condition, and history in reporting]*
Commenter **General Electric Oil & Gas**	
PHMSA should include gathering lines in its regulatory framework. Some of these pipelines run at high pressure, and some are located within potential HCA's. PHMSA should encourage these pipelines be made to accommodate ILI tools as soon as practicable.	*Gathering lines should be included in PHMSA's regulatory framework*
PHMSA should encourage these pipelines be made to accommodate ILI tools as soon as practicable.	*Gathering lines should be encouraged to accommodate ILI tools as soon as practicable*
Commenter **Janet Alderton**	
I conclude that the First and Second Proposals are not only unnecessary, but may aggregate data that are inaccurate or misleading.	*Reporting requirements are unneccesary and may be innaccurate or misleading*
Commenter **Judy Skog**	
I applaud your inclusion of all hazardous liquids lines in the reporting. I urge you to require GIS mapping coordinates in that reporting.	*Broaden requirements [Require GIS mapping information]*
Commenter **Kathy Hollander**	
GIS mapping information should be required for gravity fed and gathering pipelines	*Broaden requirements [Require GIS mapping information]*
Minimum safety standards should be set for these lines as well.	*Broaden requirements [Require minimum safety standards]*
Commenter **League of Women Voters of California**	

The annual reporting requirement for gravity fed and gathering lines that is included in the proposed rule for pipelines under your jurisdiction is a positive step. However, mapping information and minimum safety standards are essential for these pipelines as well, and should be added to your requirements.	*Broaden requirements [Require minimum safety standards]*
Inspection reports, notices of violation, and similar documents should be readily available to the public.	*Require inspection reports, notices of violation, and similar documents to be made available to the public*
The annual reporting requirement for gravity fed and gathering lines that is included in the proposed rule for pipelines under your jurisdiction is a positive step. However, mapping information and minimum safety standards are essential for these pipelines as well, and should be added to your requirements.	*Broaden requirements [Require GIS mapping information]*

Commenter **Louisiana Mid-Continent Oil and Gas Association (LMOGA)**

The proposed amendment to amend Part 195.1 that will extend subpart B to all gathering lines will have enormous fiscal impact to the regulated community in Louisiana. In discussions with the Office of Conservation, it is estimated that the number of regulated lines will double if this rule is adopted. Subpart B entitled "Annual, Accident, and Safety-Related Condition Reporting", includes numerous requirements. Of significant note is the accident reporting requirements. Most if not all of these criteria are already required to be reported by gathering lines under other existing federal and state regulations (e.g. Louisiana State Police reporting requirements, etc.). These requirements unnecessarily duplicate existing provisions.	*Accident reporting requirements are duplicative. The rule should not expanded to gathering lines until this issue is addressed.*
Finally, the requirement of subpart B to add these gathering lines to the National Pipeline Mapping System adds another burden to the industry with questionable benefit. A current pipeline map of pipelines overlaid on Louisiana already looks like a plate of spaghetti. See the link to the Energy Information Agency interactive map at the following link: http://www.eia.gov/statel?sid=LA. Doubling this chaos to add hazardous liquid gathering lines makes any mapping virtually useless. Should these lines have to be mapped, there may be incidental wetland environmental disbenefits for teams to enter the wetlands and track these lines. It will likely require Corp of Engineers and state coastal zone permitting. As access will need to be by watercraft (boat, airboat, hovercraft, etc.), all of these are expenses that must be addressed. The time allowed for PHMSA to require compliance must also recognize these hurdles.	*GIS mapping is unnecessary and could have wetland environmental disbenefits requiring permitting in order to comply. The rule should not expanded to gathering lines until this issue is addressed.*

Commenter **Offshore Operators Committee**

In addition, there is concern about possible NPMS reporting. Centerline data on many of these lines is not available so NPMS reporting would require a long timeline and incur a substantial cost burden on pipeline operators. Even the offshore lines forwhich BSEE has basic data would require a great deal of effort to verify and convert to what is needed for NPMS reporting. It was stated by PHMSA in one of the conference calls on this subject that NPMS reporting will not be required at this time. The OOC wishes to go on the record that adding this requirement in the future would be a significant change and respectfully requests that PHMSA consider the potential impacts a requirement like this would have on industry in any rulemakings on this subject in the future.

NPMS reporting should not required in this rule

Commenter **Pipeline Safety Coalition**

PSC is pleased with the initial extension of reporting data by adding 49 CFR 195.1(a)(5) to require that the operators of all
gravity and gathering lines comply with requirements for submitting annual, safety-related condition, and incident reports and strongly recommends incorporating requirements that all pipelines, regardless of location, become jurisdictional and provide GIS mapping coordinates.

Broaden requirements [Require GIS mapping information]

PSC suggests that minimum safety standards be added to the rules/standards as non-HCA HL pipelines, we suggest the
final rule require these lines to meet minimum pipeline safety standards.

Broaden requirements [Require minimum safety standards]

Commenter **Pipeline Safety Trust**

One change we suggest that would at least allow PHMSA to gather some of the information necessary to investigate how IM is and is not working would be for PHMSA to require operators to include in its annual report the reasons for each repair (based on immediate, 270-day, 18-month, or other conditions) it was made and whether that repair location was inside or outside an area that could affect an HCA.

Broaden requirements [Include the reasons and location (HCA or not) of repairs in operators' annual report]

We would like to see this reporting extended to require submissions to NPMS for geographic information system mapping purposes.

Broaden requirements [Require GIS mapping information and submission of GIS information to NPMS]

Given the relatively small cost of subjecting them to the same standards as non-HCA HL pipelines, we suggest the final rule require these lines to meet minimum pipeline safety standards

Broaden requirements [Require minimum safety standards]

Commenter **St Croix River Association (SCRA)**

However, the proposed rules do not require GIS mapping information or any minimum safety standards for the lines that will be covered under this expansion.
We recommend that GPS mapping information be required.
We recommend that minimum safety standards be added to the rules.

Broaden requirements [Require GIS mapping information and minimum safety standards]

Commenter **State of Washington Citizens Advisory Committee on Pipeline Safety**

Washington does not have any gravity or gathering lines in the state. In the interest of national
pipeline safety, the Committee supports the reporting requirement recommendation for gravity
and gathering lines contained in the NPRM. We also ask that these lines be brought under basic
safety regulations as soon as possible.

Broaden requirements [Require minimum safety standards]

Commenter **Texas Pipeline Association**

In order to facilitate the limited reporting contemplated by this rulemaking, TPA also recommends that PHMSA adjust the instructions for annual and incident reports to limit the information reported by gravity pipeline operators to relevant data elements and to readily available information	*Clarify and tailor the reporting requirements*
reporting required for certain pipelines be limited to annual and incident reports . . . And that safety-related condition reports not be required at this time because many of the situations triggering safety-related condition reporting are tied to issues of compliance with safety regulations. At this time, there are no safety regulations applicable to gravity hazardous liquid pipelines, so there would be nothing to trigger a safety-related report from such pipelines.	*Narrow requirements [Eliminate safety-related condition reporting requirement and limit reporting to annual and incident reports]*

Commenter **Tip of the Mitt Watershed Council**

In addition to reporting requirements, we believe that these pipelines should also be subject to the minimum federal pipeline safety standards.	*Broaden requirements [Require GIS mapping information]*

Commenter **Western Organization of Resource Councils**

Although we support this enhanced requirement, we urge PHMSA to also require pipeline operators to provide GIS mapping information and to meet minimum safety standards for all pipelines. States often do not require companies to provide a GIS map of smaller gathering lines, and many states have hundreds of unmapped pipelines, extending thousands of miles and presenting many safety issues. It is important to require minimum safety standards for all pipelines including gathering lines unregulated by the states.	*Broaden requirements [Require GIS mapping information]*

Issue ID 1.3 Inspections of pipelines following extreme weather events

Subissue **Define extreme event**

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

Regulatory clarity is necessary to alert operators on the circumstances that PHMSA expects would indicate potential damage to facilities. API and AOPL suggest that PHMSA consider adopting a standard for other similar events, such as “other similar events with a significant likelihood of damage to infrastructure. [p.8]	*Need to clearly define conditions triggering extreme weather events*

Commenter **Congresswoman Lois Capps**

I am concerned that the definition of a qualifying event and the responsible party for such a determination is too vague as written. The inclusion of definitions and or citations of existing definitions would work to improve the clarity of this language.	*Need to clearly define conditions triggering extreme weather events*

Commenter **Cook Inlet Regional Citizens Advisory Council (RCAC)**

Cook Inlet RCAC supports this proposed requirement, although it is important to note that "extreme" weather varies significantly across the U.S. In Cook Inlet, extreme events range from high winds to heavy precipitation to sea ice to volcanic or seismic emergencies. Unlike other parts of the U.S., our extreme weather events are not always named storms or hurricanes, but can be just as severe.	*Need to clearly define conditions triggering extreme weather events [Get input from operators and regulators at the state and regional level]*

Commenter **County of Santa Barbara**

This proposal should be clarified by including definitions of `extreme weather events', `natural disaster', and `similar events'. The proposed regulations should specify a particular threshold at which action would be required. Furthermore, the proposal should identify specific remedial actions, such as shutting down the affected pipeline or reducing operating pressure immediately after an "event" until at least the time of the inspection. Finally, this proposal should also clarify what inspection procedures are appropriate for certain types of pipelines to ensure that the condition of the affected pipeline is adequately characterized (e.g. visual inspection of pipeline corridor, inspection of surrounding topography, review of pipeline operational data, etc.).

Need to clearly define conditions triggering extreme weather events [Define of extreme weather events, natural disaster, and similar events]

Commenter **Energy Transfer Partners**

1. What constitutes such a triggering event?
a. The same or similar events in different geographic locations may have different impacts,
from benign to severe.
b. The same event in a single location may have different impact on different operators,
from benign to severe.
2. Who decides whether an event is a triggering event for 195.414 or not?

Need to clearly define conditions triggering extreme weather events

Commenter **Environmental Defense Center**

This proposed rule, however, should be revised to provide specific, enforceable requirements for shutdown or other remedial action should an inspection reveal damage or anomalies. The rule should also clarify the type of events covered and the inspection methodology required (e.g., visual inspection, in-line inspection ("ILI"), etc.). Finally, the rule should require immediate reporting to PHMSA and relevant federal, state and local agencies.

Need to clearly define conditions triggering extreme weather events

Commenter **Gas Processors Association**

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

Provide definition of which events require response and inspection or establish performance expectations without partially defining the criteria

Commenter **Independent Petroleum Association of America**

The Proposed Rules seek to mandate inspection of pipeline segments in areas that are subject to extreme weather events, natural disasters or other similar events (See 80 Fed. Reg. at 61639). As presented, very little guidance is provided as to what events trigger the requirement. Does a 10-year-flood require inspection? Does an earthquake reaching 2.2 on the Richter scale require an inspection? Does a Category 2 hurricane require an inspection? IPAA's concern is that the Proposed Rules do not allow operators to answer these questions and intelligently comply.

Need to clearly define conditions triggering extreme weather events

Commenter **Louisiana Mid-Continent Oil and Gas Association (LMOGA)**

Subsection 414(a) - This subsection outlines the types of weather events that require inspection of pipelines within 72 hours. While many obvious events are listed, the addition of "other similar event" is included. What entity identifies this type event? As Louisiana experiences many varied weather events, LMOGA is concerned about this provision being "over" invoked by agencies. LMOGA offers the following two examples.	*Need to clearly define conditions triggering extreme weather events [define other similar events]*

Commenter **McChord Pipeline Co.**

McChord Pipeline Co. (MPL) would like to see a measurable and quantifiable definition of what constitutes an extreme weather, natural disaster, and other similar event included in this rule. The extreme weather, natural disaster, and other similar event need to be specific to the location of the pipeline.	*Need to clearly define conditions triggering extreme weather events [Allow tailoring to the specific location of the pipeline]*
McChord Pipeline Co. (MPL) would like to see a measurable and quantifiable definition of what constitutes an extreme weather, natural disaster, and other similar event included in this rule. The extreme weather, natural disaster, and other similar event need to be specific to the location of the pipeline.	*Need to clearly define conditions triggering extreme weather events [Allow tailoring to the specific location of the pipeline]*

Commenter **National Association of Pipeline Safety Representatives (NAPSR)**

NAPSR also feels that addition of definitions for "natural disaster", "hurricane", "flooding" and "extreme weather event" should be added. Note: It may be adequate to add only the definition of "natural disaster" to this subsection. "Natural Disaster" is defined as "an event or force of nature that has catastrophic consequences, such as avalanche, earthquake, floor, forest fire, hurricane, lightning, tornado, tsunami, and volcanic eruption." (Source: Dictionary.com.)	*Need to clearly define conditions triggering extreme weather events [Include definitions for natural disaster, hurricane, flooding, and extreme weather event]*

Commenter **Pipeline Safety Trust**

without definitions of "extreme weather event" or "natural disaster", or "other similar event", enforcement of this regulation could become very subjective and difficult. Definitions of these terms are are also necessary for an operator to determine when the proposal's 72-hour maximum period for assessment begins or ends. Useful definitions could come from the "Severe Weather" definitions from NOAA's NWS	*Need to clearly define conditions triggering extreme weather events [Clarification of the definition of extreme weather event, natural disaster, and other similar event could come from the NWS]*

Commenter **State of Washington Citizens Advisory Committee on Pipeline Safety**

The Committee supports the proposed inspection requirements after extreme weather events. However, we believe strongly that there needs to be clarity around the definition of what constitutes an “extreme weather event.” The requirements in this recommendation would be a 49 CFR 195 subpart F, operations and maintenance, requirement, necessitating procedures for the operator and regulator to follow. It will be critical to ensure the threshold for what an “extreme weather event” is and that the operator and regulator know precisely what would trigger the event and how to determine the time of the event.	*Need to clearly define conditions triggering extreme weather events*

Commenter **State of Washington Utilities and Transportation Commission**

The commission supports the proposed requirements for inspections after extreme weather events. However, the commission strongly recommends more clarity around the definition of "extreme weather event" to provide more guidance to states and operators about when inspections are required. The term "extreme weather event" is difficult to define, as it varies from region to region and potential damage is heavily influenced by the geography and design of the pipeline.

Need to clearly define conditions triggering extreme weather events [Allow tailoring to the specific location of the pipeline, clarify what triggers the events, and how to determine the timing of the event]

Commenter **Texas Pipeline Association**

As proposed, the rule is unclear concerning which events will trigger a required inspection because of the inclusion of "other similar events" in the rule language and the variability in the intensity of the listed events. Similarly, the term "potentially affected facility" leave an operator open to second-guessing on the facilities that should be inspected. [suggested language: 195.414(a) "following an event that is likely to cause damage to pipeline facilities due to that intensity of the event and the environment in which the pipeline facilities operate, an operator must inpsect all its pipeline facilities in the area of the event to determine if any damage has occurred to the pipeline facilities that would prevent continued safe operation of the pipeline facilities"

Need to clearly define conditions triggering extreme weather events [define other similar events]

As proposed, the rule is unclear concerning which events will trigger a required inspection because of the inclusion of "other similar events" in the rule language and the variability in the intensity of the listed events. Similarly, the term "potentially affected facility" leave an operator open to second-guessing on the facilities that should be inspected. [suggested language: 195.414(a) "following an event that is likely to cause damage to pipeline facilities due to that intensity of the event and the environment in which the pipeline facilities operate, an operator must inpsect all its pipeline facilities in the area of the event to determine if any damage has occurred to the pipeline facilities that would prevent continued safe operation of the pipeline facilities"

Need to clearly define potentially affected facility

Commenter **Tip of the Mitt Watershed Council**

While we are supportive of the requirement for operators to perform inspections within 72 hours after the cessation of an extreme weather event, natural disaster, or other similar event, we recommend that definitions be provided for clarity. Without specific definitions, operators are able to arbitrarily determine if a weather event was “extreme” or if a situation occurred that would require the additional inspection. The lack of a definition could hinder both implementation of this provision as well as enforcement capabilities.

Need to clearly define conditions triggering extreme weather events

Subissue **Implementation schedule**

Commenter **American Gas Association (AGA)**

AGA encourages PHMSA to remove the proposed 72 hour time period for conducting inspections post extreme weather events and limit any suggested timeframe to "after the affected area can be safely accessed by the personnel and equipment required to perform the inspection as determined under paragraph (B) of this section." After an extreme weather event, operating companies should be focused on the safety of the public, employees, and integrity of company assets, not an arbitrary timeline within federal regulations. By eliminating the 72 hour reference and focusing on safety, the regulation would appropriately place the burden on operators to evaluate and determine when it is safe for personnel and equipment to perform the inspections. Requiring the 72 hour reference creates a presumption for a 72 hour period, despite the reference to personnel and equipment safety. If an inspection were delayed past the 72 hour mark, attention and resources would need to be expanded substantiating the judgement call. If PHMSA removes the 72 hour proposal, the pressure to put company employees in potentially unsafe situations would be eliminated. Safety should be the utmost consideration when deciding when an inspection can be completed and the regulations should reflect this priority.	*Define and clarify timing [Eliminate the 72 hour period in favor of focusing strictly on timing based on safe conditions]*

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

In order for operators to comply with obligations under the proposed rule and protect public safety, including the safety of their own personnel, API and AOPL recommend that PHMSA define cessation as "the point in time when no further threats to personnel safety or equipment exist in the affected area, allowing for safe access by pipeline personnel and equipment." [p.8] However, consistent with the Associations' proposed definition of "cessation" discussed above, the 72-hour window to perform the inspection would only commence once personnel and equipment could safely access the affected area. [p.10]	*Define and clarify timing*
API and AOPL recommend that additional time be allowed if an operator determines that the required inspection method cannot be completed within 72-hours with documentation to support the time extension… Operators would record the reasons for the delay and maintain that information with the inspection records. [p.9] The Associations ask that PHMSA acknowledge the very likely potential for inspections to exceed the 72-hour proposed timeframe due to the limited availability of third-party resources in the final rulemaking. [p.9]	*Allow extensions to the 72-hour inspection deadline*

Commenter **Energy Transfer Partners**

72 hours is a precise number – who decides and how is it decided exactly when this 72-hour clock starts?	*Define and clarify timing*

Commenter **Gas Processors Association**

PHMSA has proposed the inspection occur within seventy-two (72) hours after cessation of the event. Does this mean that PHMSA expects the inspection to be started, in-progress, or completed? In large scale events, such as Hurricane Rita and flooding of the San Jacinto River, there may not be resources available, such as generators or ILI tools for all operators to accomplish the goals PHMSA is proposing. As an alternative to creation of a completely new regulatory section, PHMSA could modify the section requiring Emergency Plans (§ 195.402(e)) to require an inspection following events to determine if an emergency situation has developed and, if so, the provisions in the operator's emergency plan should be implemented. This would be a less ambiguous way to achieve the desired goal.	*Define and clarify timing [Cessation should be defined as "the point in time when the operator determines no further threats to personnel safety or equipment exists"]*

PHMSA has proposed the inspection occur within seventy-two (72) hours after cessation of the event. Does this mean that PHMSA expects the inspection to be started, in-progress, or completed? In large scale events, such as Hurricane Rita and flooding of the San Jacinto River, there may not be resources available, such as generators or ILI tools for all operators to accomplish the goals PHMSA is proposing. As an alternative to creation of a completely new regulatory section, PHMSA could modify the section requiring Emergency Plans (§ 195.402(e)) to require an inspection following events to determine if an emergency situation has developed and, if so, the provisions in the operator's emergency plan should be implemented. This would be a less ambiguous way to achieve the desired goal.	*Modify Emergency Plans provision to require an inspection to determine if an emergency situation has developed and then implement the operator's emergency plan if necessary (suggested language provided)*

Commenter **Louisiana Mid-Continent Oil and Gas Association (LMOGA)**

Subsection 414(c) - This subsection outlines the timeframe of 72 hours in which inspections must "occur." The proposal starts the timeline at the "cessation of the event." What entity identifies the cessation of the event?" Often a weather event is over but emergency orders from local governments preclude access to an area. This is regardless of whether it can be done safely or not. A "72-hour" response may be delayed solely to political reasons. This does not appear to be considered in the proposal. Additionally, due to the propensity of hazardous liquid lines in southeast Louisiana and the geography (as previously discussed), it may be impossible for all the companies to mobilize the resources needed may not be available. As many of these resources (boats, air boats, helicopters, etc.) evacuate in an extreme weather event, they may not be back in place and available within the 72-hour period specified in the proposal.	*Define and clarify timing [Clarify "cessation of the event" and allow leniencies to the timeline based on conditions post-weather event]*

Commenter **Montana Department of Environmental Quality**

PHMSA should consider revising the amount oftime an operator must perform an additional inspection from 72 hours down to 36 hours or a timeframe less than three days. If a natural disaster were to occur and operators were allowed to continue with operations for an additional 72 hours this could exacerbate a potential problem. The requirement of 72 hours would be the maximum amount of time that could lapse until the inspection needs to take place, but this seems too significant an amount of time. Giving operators 36 hours is based on the concept that during an extreme weather event the operator could be mobilizing and getting personnel ready to do an inspection. So once that the event has concluded the inspection of the pipe could happen rapidly. If an operator cannot get the inspection done within 36 hours, they would need to provide specific justification of the reasoning to PHMSA and request an exemption to this timeframe.	*Define and clarify timing [Reduce response timeline to 36 hours]*

There is no justification in the proposed rule on why PHMSA believes that 72 hours is a sufficient amount of time. PHMSA should consider putting their reasoning of why they believe 72 hours is appropriate. This would allow for a better understanding of PHMSA's decision to stakeholders.	*Define and clarify timing [Provide justification for 72 hour timeline]*

Commenter **National Association of Pipeline Safety Representatives (NAPSR)**

NAPSR agrees with and generally supports the addition of this subsection. NAPSR also feels that the reference in 195.414 (c) Time Period, the “cessation of event” could be more clearly defined. For example, a flooding event may occur for a day or so, but is the cessation of event when the floodwaters go down or drop below flood level or is there some other criteria? The same reasoning could apply in the example of a hurricane; Is the hurricane over when the wind speed drops below a certain level, or when the sun is shining? NAPSR feels that state and federal regulators need to know when the clock starts in order to provide effective enforcement. The operators as well need a clear set of criteria for this requirement so that they can determine when to attempt to send crews to the disaster location to begin assessments.	*Define and clarify timing [Clarify the definition of "cessation of event"]*
The complimentary statement of “or as soon as the affected area can be safely accessed” also needs to have a set of clear criteria. NAPSR feels that PHMSA should require the operators to clearly list a set of reasonable and detailed criteria for response in their operating procedures.	*Define and clarify timing [Clarify "or as soon as the affected area can be safely accessed"]*

Commenter **Offshore Operators Committee**

In addition, after a hurricane, platforms must be inspected for integrity and safety before any inspections of pipelines beyond an initial overflight can even begin. These platform inspections take top priority and can extend well past the 72 hour window that PHMSA has proposed. Any issues found on the platforms will further delay inspections of the pipelines. Availability of helicopters and crew boats after major events can also impact the timing with which inspections can occur. For PHMSA to have a separate requirement in these instances is duplicative and could possibly contradict orders issued by BSEE. OOC requests that PHMSA consider coordination with BSEE and the Coast Guard for activities that occur after hurricanes and reconsider this portion of the NPRM for all of the reasons proposed by API/AOPL.	*Define and clarify timing [Consider coordination with BSEE and the Coast Guard for activities that occur after hurricanes]*

Commenter **Sharon Austry**

read your proposals and I don't understand why on earth you would increase the time between inspections from 5 to 10 years when they should be inspected every month and why you would wait up to 72 hours before you would investigate a leak. I think that there should be monitors on every well and alarms that go off like tornado warnings after every leak. It about time to put the safety of the public before the profits of the gas and oil industry.	*Define and clarify timing [Require shorter deadline than 72 hours]*

Commenter **Spectra Energy Partners**

SEP also requests that PHMSA provide operators with discretion to determine the “cessation” of a weather event, as that point would mark the beginning of the timeframe within which operators must complete their inspection.	*Define and clarify timing [Allow operators to determine "cessation" of a weather event]*

SEP also believes the 72-hour timeframe to complete the inspection following cessation
of a triggering event will be impracticable to meet in most cases. Many events that will trigger
the inspection requirement will affect multiple operators who will need to compete for the same
resources to conduct the inspections. Completing necessary inspections on all potentially
affected pipelines for all operators will often be impracticable due to limitations on availableresources. Additionally, even when a flooding event “ceases”, it may be unsafe for personnel
to access the location to conduct the inspections, especially in the case where a diver survey is
needed. Furthermore, mobilization of resources to the location may take more than three (3)
days, especially in cases where an in-line inspection or pressure test is warranted. SEP urges
PHMSA to recognize that the 72-hour timeframe will often be impracticable to meet, and
include provision in the final rule allowing an operator to document a justification for
exceeding the 72-hour timeframe.

Define and clarify timing [Allow justifications for exceeding the 72-hour timeframe]

Commenter **Tip of the Mitt Watershed Council**

In addition, we recommend that timeframes be specified for the operator to take appropriate remedial action to ensure the safe operation of the pipeline. If an operator identifies anomalies that could threaten the integrity and safe operation of the pipeline within 72 hours of an event, it is imperative that timely action be taken to minimize the risk. The absence of time frames to mitigate or repair any anomalies does not ensure this will occur expeditiously and the timing for repair or mitigation is left entirely to the operator’s discretion. This ultimately serves to undermine the purpose of the rule, ensuring that our nation’s waterways are adequately protected in the event of a natural disaster or extreme weather.

Implement a time frame for mitigating or repairing anaomalies

Subissue **Risk factors**

Commenter **General Electric Oil & Gas**

We encourage PHMSA to consider that operators who use active or near-real-time risk management approaches (such as those available from GE's IPS) are able to quickly assess the impact of events and the resulting change in conditions. Those operators can use assessments to prioritize areas of pipeline to be inspected first.

Consider ability to prioritize areas of pipeline for inspection

Subissue **Scope of requirements**

Commenter **Accufacts**

I advise that 195.414 be incorporated, but additional regulatory efforts also focus on identification and prevention of pipeline failure from such threats as extreme weather and natural disaster, which is one of the core objectives of IM. In situations such as the 2011 pipeline full bore rupture failure in the Yellowstone River, prevention was the most prudent approach (that was not obviously utilized) for this highly predicable flooding threat, and inspection after the natural event would have not prevented this full bore rupture. The Yellowstone River is the last free flowing undammed river in the U.S., well known for very high seasonal water flow rates and rockbed river scouring at many locations, that had caused previous pipeline scouring failures. Ironically, the state of Montana had a regulation requiring pipeline operators to address scouring threats in pipeline river crossings.

Broaden requirements [Require proactive measures based on extreme weather events; example of scouring of pipeline crossings]

Commenter **Alaska Wilderness League et al.**

Section 195.414 requiring inspections within 72 hours of pipelines in areas affected by extreme weather, natural disasters, earthquakes and other similar events. This section does not require any pro-active measures to be taken by operators before predictable events however, e.g., flooding, and it should. Mandatory prevention measures should include shutting down pipeline operations in case of an imminent flood, which could have prevented the Exxon Mobil 2011 Yellowstone River spill (other operators near this pipeline did shut down);

Broaden requirements [Require proactive measures based on extreme weather events]

Commenter **Alliance for Great Lakes et al.**

We support this added protection measure, but also suggest the addition of proactive measures. For instance, if a pipeline is located in a state that has been affected numerous times by hurricanes, the pipeline should be inspected generally and regularly, as opposed to just following a disaster.

Broaden requirements [Require proactive measures based on extreme weather events]

We support this added protection measure, but also suggest the addition of proactive measures. For instance, if a pipeline is located in a state that has been affected numerous times by hurricanes, the pipeline should be inspected generally and regularly, as opposed to just following a disaster. Pipeline water crossings should also be inspected before and after high flow events, and other typical high-flow periods, to ensure pipeline integrity.

Broaden requirements [Require additional inspections for pipeline water crossings]

Commenter **American Gas Association (AGA)**

AGA supports API & AOPL's comments that the proposed remedial action requirements found under proposed §195.414(d)3 are duplicative of existing requirements for emergency response plans, found in §195.402 – Procedural manual for operations, maintenance, and emergencies, for hazardous liquid operators. The existing regulations already require operators to develop written procedures for conducting normal operations and maintenance activities as well as handling abnormal operations and emergencies, which would encompass the proposed remedial action requirements.

Requirement is duplicative [Already covered by requirements for procedures to handle abnormal operations and emergencies]

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

Therefore, operators already address and complete many of the remedial actions proposed by PHMSA in their emergency response plans. As a result, API and AOPL believe the proposed language is duplicative and should be modified to only include those actions that are not addressed in Section 195.402(e). Alternatively, if explicit changes are needed to address extreme weather events, API and AOPL request that PHMSA modify Section 195.402(e)(4) by adding the three newly proposed remedial actions that are not currently included in that section: modifying, repairing, or replacing any damaged pipeline facility; preventing, mitigating, or eliminating any unsafe condition in the pipeline right of way; and perform additional patrols, surveys, tests or inspections. [p.6]

Requirement is duplicative [Requirements already contained in the emergency response plans]

The current language does not recognize the nuances in the particular physical design and construction of a pipeline in the area of the potential exposure. Such particular design and construction characteristics might, in and of themselves, mitigate the exposure or risk. The Associations further request recognition in the final rulemaking that many of these events, due to variables like intensity or duration of the event, geographic region affected, assets located in the affected areas, and design capacity of the pipeline assets to withstand the conditions of the extreme events, will potentially have widely disparate impacts on pipeline assets and operators. [p.7]	*Allow the operators to consider risk factors [Consider nuances in the particular physical design and construction of a pipeline in the area of the potential exposure]*
However, the standard of ensuring that “no conditions exist” is overly broad and potentially impossible for operators to demonstrate. API and AOPL agree with the need to conduct inspections to identify and remediate any adverse conditions that exist, but the standard required of operators must be feasible. The Associations recommend the proposed text at Section 195.414(a) be modified, with new language indicated in bold, as follows: “…an operator must inspect all potentially affected pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline ensure that no conditions exist that could adversely affect the safe operation of that pipeline.” [p.8]	*Define performance criteria to be achievable*
Commenter **Congresswoman Lois Capps**	
Additionally, I am concerned that there is too much leeway for interpretation as to what constitutes an “appropriate method for performing the inspection.” This terminology also should be clearly defined.	*Clarify definition of "appropriate method for performing the inspection"*
I am concerned that the definition of a qualifying event and the responsible party for such a determination is too vague as written. The inclusion of definitions and or citations of existing definitions would work to improve the clarity of this language.	*Clarify the definition of the responsible party*
Commenter **County of Santa Barbara**	
This proposal should be clarified by including definitions of `extreme weather events', `natural disaster', and `similar events'. The proposed regulations should specify a particular threshold at which action would be required. Furthermore, the proposal should identify specific remedial actions, such as shutting down the affected pipeline or reducing operating pressure immediately after an "event" until at least the time of the inspection. Finally, this proposal should also clarify what inspection procedures are appropriate for certain types of pipelines to ensure that the condition of the affected pipeline is adequately characterized (e.g. visual inspection of pipeline corridor, inspection of surrounding topography, review of pipeline operational data, etc.).	*Broaden requirements [Identify remedial actions and inspection procedures]*
Commenter **Energy Transfer Partners**	
Because of the great variability in what the answers to these questions might be, it seems clear that this proposal does not lend itself well to prescriptive requirements, but rather the needs for inspections, the types of inspections themselves and the required timing of the inspection should be determined caseby- case by the operator on a risk basis. It is reasonable for operators to have internal processes by which to make these determinations. If the above risk-based premise is accepted, the next question is whether §195.414 is needed as a separate requirement at all. ETP believes that it is not, but rather the intent can be met by slight, if any, modification to existing requirements. [suggested language: changing the last phrase of §195.402(e)(2) to “and natural disaster or extreme weather event potentially affecting pipeline facilities.” and the last phrase of §195.403(a)(3) to “and take appropriate corrective or investigative action.”]	*Requirement is duplicative [Modify existing requirement (195.402, 195.403) instead of 195.414]*

What inspections must be performed? a. If ILI, it will be virtually impossible to do within 72 hours by a single operator. b. If a widespread event, inspection by multiple operators may be impossible, see a.	*Clarify required inspection methods*
Commenter **Environmental Defense Center**	
This proposed rule, however, should be revised to provide specific, enforceable requirements for shutdown or other remedial action should an inspection reveal damage or anomalies. The rule should also clarify the type of events covered and the inspection methodology required (e.g., visual inspection, in-line inspection ("ILI"), etc.). Finally, the rule should require immediate reporting to PHMSA and relevant federal, state and local agencies.	*Broaden requirements [Require shutdown or remedial action after inspection that reveals damage or anomalies]*
This proposed rule, however, should be revised to provide specific, enforceable requirements for shutdown or other remedial action should an inspection reveal damage or anomalies. The rule should also clarify the type of events covered and the inspection methodology required (e.g., visual inspection, in-line inspection ("ILI"), etc.). Finally, the rule should require immediate reporting to PHMSA and relevant federal, state and local agencies.	*Clarify required inspection methods*
This proposed rule, however, should be revised to provide specific, enforceable requirements for shutdown or other remedial action should an inspection reveal damage or anomalies. The rule should also clarify the type of events covered and the inspection methodology required (e.g., visual inspection, in-line inspection ("ILI"), etc.). Finally, the rule should require immediate reporting to PHMSA and relevant federal, state and local agencies.	*Broaden requirements [Require immediate reporting]*
Commenter **General Electric Oil & Gas**	
PHMSA should clarify that the requirement to inspect pipelines within 72 hours of a rain event refers to inspections other than ILI. Pipelines in waterways can become exposed and compromised following rain events, and it is important for operators to visually inspect these lines quickly and to implement necessary remedies. Organizing ILI inspections to check for strain or mechanical damage, however, takes longer than 72 hours	*Clairfy that the 72 hour timeline refers to inspections other than ILI*
Commenter **Gulf Restoration Network**	
Notifying the public of any pipeline incident is an essential aspect of this rule. When a disaster has occurred very minute after a pipeline leak or explosion poses numerous threats to water, wetlands, and communities at a time when they are most vulnerable.	*Require notification of the public*
Commenter **Joletta Bird Bear**	
revised regulation must require local physical monitoring and technical monitoring designed to catch the smallest fracture on an existing pipeline	*Broaden requirements [Require local physical monitoring and technical monitoring]*
Commenter **Kathy Hollander**	
In this era of global warming, pipelines should be analyzed for severe weather impacts, such as floods, intense rainfalls, drought, intense heat failures on seals and Orings.	*Broaden requirements [Require analysis, develop proactive measures and establish preventative requirements]*
Commenter **Libby Willis**	

North Texas, where Fort Worth sits at the heart of the natural gas rich Barnett Shale, is highly prone to extreme weather, natural disasters, and other similar events. In the last couple of years, we have experienced record drought and then record flooding all over Texas and especially in North Texas. Our area is prone to experiencing flash floods and tornadoes. Just days ago, on December 26, 2015, our area experienced the often forecast and much dreaded EF 3 and EF 4 tornadoes in the greater Dallas-Fort Worth Metroplex. At least eleven people died in these tremendous 180 mile an hour storms, many in their cars on Interstate 30 after the winds picked up the cars and then slammed them down.
I am reminded as well of Fort Worth pipeline incidents over the last several years. At least one pipeline near Loop 820 failed at the high peak drive time of 3:30 to 7:00 p.m. Failure of the pipeline cheek by jowl next to a shopping center and a packed freeway was everyone's worst nightmare. Traffic was stopped and could not move while first responders tried to get to the pipeline to check out the seriousness of the event. Drivers were, in essence, sitting ducks for any potential explosion from the failed pipeline.
The seriousness of our weather events, the large numbers of pipelines in our area carrying all kinds of materials, from hazardous liquids to natural gas, and the proximity of those pipelines to areas of high volumes of people (whether freeways or shopping centers, etc.) mean it is only prudent that any new rule on hazardous liquids pipelines should require operators to inspect on a regular timetable a pipeline segment that was potentially affected by such an event not just within 72 hours after the event occurs but BEFORE such extreme weather, natural disasters and similar events occur. The goal of the rule should be proactive inspection on the part of the operators, not just reactiveness.

Broaden requirements [Develop proactive measures and establish preventative requirements]

Commenter **Louisiana Mid-Continent Oil and Gas Association (LMOGA)**

Louisiana is subject to several extraordinary events. These are most likely to be hurricanes but also include: spillway openings, high/low river flows, rainwater flooding, etc. Louisiana has experienced all of these in the last 10 years. Pipeline companies operating in Louisiana are experienced in responding to these events and do not need a regulatory requirement to do such.

Requirement is duplicative [Existing industry practices]

Subsection 4 14(d) - This subsection outlines the actions to be taken as part of a "remedial response."
While LMOGA has no problems with the potential actions listed, the provision "but are not limited to"
again establishes a potential conflict between the pipeline companies and the regulating agencies.
Nothing in the proposal prohibits a regulatory agent from requiring a response that is absolutely absurd
and costly under the authority of this language. The company does not appear to have recourse in this
dispute. Again, this broad language in the proposal causes LMOGA great concern.

Revise and clarify overly broad language ["but not limited to" in terms of the remedial response]

Section 416 - This subsection outlines the actions to be taken as part of pipeline assessments. Again,
these words are used that can be broadly interpreted resulting in conflicts between the companies and the
regulatory agencies. Some of this wording includes: "substantially equivalent"; "could"; "adequate";
"sufficient"; "condition"; and, "relevant." This broad language in the proposal causes LMOGA great
concern and should be clarified.

Revise and clarify overly broad language [Section 416]

Commenter **Montana Department of Environmental Quality**

In most natural disasters, other than an earthquake, an operator would be aware that a natural disaster is going to be occurring that could affect the pipeline. The operator should consider shutting down operations of the pipeline until an inspection has taken place to verify the integrity of the pipeline. If a release of product from a pipeline were to take place, the product would not be under pressure and the volume of a release could be minimized.

Broaden requirements [Develop proactive measures and establish preventative requirements]

Commenter **National Association of Pipeline Safety Representatives (NAPSR)**

NAPSR has also observed that some weather conditions (such as heavy rains in areas with little or no watershed) can produce conditions that may expose pipelines or subject them to stresses. Thus, NAPSR suggests the following wording for 195.414 (a)
General: "Following an extreme weather event such as a hurricane or flood, an earthquake or natural disaster, heavy rains, etc. that could result in changes to soil or support conditions, or other similar event, an operator must inspect all potentially
affected pipeline facilities to ensure that no conditions exist that could adversely affect the safe operation of that pipeline."

Include additional language regarding conditions that may expose pipelines or subject them to stress

Commenter **Offshore Operators Committee**

the OOC asks that PHMSA consider that BSEE already issues detailed Notices To Lessees (NTLs) after hurricanes and major storms. These NTLs have instructions on what operators must do to ensure the safety of their assets after a storm. BSEE identifies the area for which to conduct facility inspections based on what areas experienced hurricane force winds, certain water depth limitations, etc. In this way they detail what locations to check as it would be impractical to inspect every single mileage of pipe offshore after every hurricane or major storm event. For PHMSA to have a separate requirement in these instances is duplicative and could possibly contradict orders issued by BSEE. OOC requests that PHMSA consider coordination with BSEE and the Coast Guard for activities that occur after hurricanes and reconsider this portion of the NPRM for all of the reasons proposed by API/AOPL.

Requirement is duplicative [Consider coordination with BSEE and the Coast Guard for activities that occur after hurricanes]

Commenter **Pipeline Safety Coalition**

While Proposal 2 is overall a reactive rather that proactive requirement there exists great opportunity to incorporate
proactive preventative based requirements. PSC offers the observation that our nation's waterways have been increasingly sullied by a cadence of ruptures (Kalamazoo, Yellowstone, Arkansas). It would seem appropriate to incorporate proactive measures in Proposal 2.

Broaden requirements [Develop more robust requirements for pipeline monitoring in waterways to include, but not be limited to: pigging requirements, annual assessment of depth of coverage, water quality monitoring]

While Proposal 2 is overall a reactive rather that proactive requirement there exists great opportunity to incorporate
proactive preventative based requirements. PSC offers the observation that our nation's waterways have been increasingly sullied by a cadence of ruptures (Kalamazoo, Yellowstone, Arkansas). It would seem appropriate to incorporate proactive measures in Proposal 2.

Broaden requirements [Develop siting and construction provisions based on environmental, personal and pipeline safety in areas known to be vulnerable]

While Proposal 2 is overall a reactive rather that proactive requirement there exists great opportunity to incorporate
proactive preventative based requirements. PSC offers the observation that our nation's waterways have been increasingly sullied by a cadence of ruptures (Kalamazoo, Yellowstone, Arkansas). It would seem appropriate to incorporate proactive measures in Proposal 2.

Identify areas particularly vulnerable to extreme weather events or natural disasters

While Proposal 2 is overall a reactive rather that proactive requirement there exists great opportunity to incorporate proactive preventative based requirements. PSC offers the observation that our nation’s waterways have been increasingly sullied by a cadence of ruptures (Kalamazoo, Yellowstone, Arkansas). It would seem appropriate to incorporate proactive measures in Proposal 2.	*Broaden requirements [Additional requirements to identify areas that are particularly vulnerable to extreme weather events]*
Commenter **Pipeline Safety Trust**	
the severe weather potential warnings would be a much more effective tool for preventing pipeline damage, as is presumably the goal of this proposed regulation, if used as a proactive tool to inspect pipelines prior to or during extreme weather and other similar events	*Broaden requirements [Recommend use of severe weather potential warnings as a proactive tool to trigger inspections]*
Commenter **St Croix River Association (SCRA)**	
Requirement for inspections of pipelines in areas affected by extreme weather, natural disasters, and other similar events . . . this is a reactive, rather than proactive requirement and does not require operators to do anything differently to prevent a pipeline segment from being affected by such events in the first place. We recommend additional requirements to identify areas that are particularly vulnerable to extreme weather events or natural disasters, e.g., stream crossings, and develop proactive preventative measures.	*Broaden requirements [Additional requirements to identify areas that are particularly vulnerable to extreme weather events]*
Commenter **State of Washington Citizens Advisory Committee on Pipeline Safety**	
The Committee also asks that analysis and any needed changes to risk assessment and mitigation requirements be added to ensure that operators are doing what is needed to prevent issues on pipelines before such weather events occur.	*Broaden requirements [Develop proactive measures and establish preventative requirements]*
The Committee also encourages PHMSA to incorporate the operators control room management process, Section 195.446, into the procedures that are developed.	*Broaden requirements [Incorporate the operators control room management process in to the procedures for extreme weather events]*
Commenter **State of Washington Utilities and Transportation Commission**	
The commission supports the proposed requirements for inspections after extreme weather events. However, the commission strongly recommends more clarity around the definition of "extreme weather event" to provide more guidance to states and operators about when inspections are required. The term "extreme weather event" is difficult to define, as it varies from region to region and potential damage is heavily influenced by the geography and design of the pipeline. To address the ambiguity of implementation and enforcement of an "extreme weather event," the commission recommends PHMSA adopt a standard that would account for any event, including weather events, natural disasters, or others, that has a likelihood of causing damage to a pipeline.	*Broaden requirements [Incorporate the operators' control room management process, Sec. 195.446]*
Commenter **Tip of the Mitt Watershed Council**	

Furthermore, extreme weather and climate events have risen in recent decades. Climate modeling results indicate that these extreme weather events are likely to increase in frequency and intensity posing a serious threat to the nation's pipeline infrastructure. While ensuring pipelines affected by extreme events are inspected within 72 hours is important, this requirement fails to proactively make the nation's pipeline network more resilient to climate change and extreme weather events. The predictions for increased frequency and intensity of rainfall events, increased number of freeze/thaw cycles, and other projected changes will affect the way pipeline operators need to design, construct, and maintain hazardous liquid pipelines. PHMSA needs to develop mitigation and adaptation measures for pipeline operators to ensure pipeline infrastructure remains safe and efficient despite a changing climate and weather events.

Broaden requirements [Establish preventative requirements for inspection of lines in particularly vulnerable areas; account for climate change]

Commenter **Western Organization of Resource Councils**

However, in order to prevent spills, companies must be required initially to put in place safety measures to protect pipelines from these events. For example, the Yellowstone River pipeline spill that occurred near Billings, MT in 2011 could have been prevented if the correct precautions had been taken to ensure the pipelines crossing the river could
withstand flood events that were predictable.2 In this case, a horizontal bore river crossing would have prevented the pipeline from rupturing and spilling into the river.3

Broaden requirements [Require proactive measures based on extreme weather events; example of scouring of pipeline crossings]

Issue ID **1.4** **Periodic assessments of pipelines not subject to integrity management (IM)**

Subissue **Costs**

Commenter **Gas Processors Association**

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

RIA underestimates costs of assessing miles using ILI

Subissue **Implementation schedule**

Commenter **American Gas Association (AGA)**

Additionally, AGA supports API & AOPL's comments on a phased approach to implementation. This will allow liquid pipeline operators time to phase in the proposed 10-year cycle for assessments of non-HCA pipeline segments.

Recommend a phased approach to implementing assessments of non-HCA pipeline segments

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

Additionally, while the proposal provides a ten-year cycle for assessments, it does not specify when operators must perform the first assessment. As it is critical for operators to understand the timeframe in which they must complete the first assessment, API and AOPL request that PHMSA clarify that operators have a ten year period for completing the first assessment, with subsequent assessments occurring once every ten years or as otherwise necessary to comply with the public safety timeframe set by the proposal. [p.13]

Recommend a phased approach to implementing assessments of non-HCA pipeline segments [10 years]

Commenter **Audubon Society of New Hampshire**

We strongly support the requirement for periodic assessment of pipelines outside high consequence areas (HCAs), which are not
currently covered under Integrity Management (IM) Program Requirements. However, we recommend that both inspection
and risk assessment be included in this requirement, and that these activities be conducted every 5 (five) years, rather than
every 10 (ten) years, as proposed.

Require that activities be conducted every 5 years

We strongly support the requirement for periodic assessment of pipelines outside high consequence areas (HCAs), which are not currently covered under Integrity Management (IM) Program Requirements. However, we recommend that both inspection and risk assessment be included in this requirement, and that these activities be conducted every 5 (five) years, rather than every 10 (ten) years, as proposed.	*Require more frequent inspections [5 years]*

Commenter **Congresswoman Lois Capps**

Furthermore, requiring inspections every ten years is insufficient to appropriately assess the risk of pipeline failure. As we have seen in my district, even a three year interval between inspections was inadequate to detect the corrosion in a timely manner to prevent the Plains All American oil pipeline from rupturing last May.	*Require more frequent inspections*

Commenter **Dakota Rural Action**

The new requirement compelling pipelines outside of high consequence areas (HCAs) to be assessed mainly by inline inspection devices once every ten years is also an improvement. We believe, however, that integrity management via inline inspections should occur more frequently than every ten years, especially for aging pipeline infrastructure across the nation, and we urge you to require that pipelines be assessed at a minimum every five years to prevent leaks, spills and other accidents. The Keystone I had 97% corrosion in areas in less than two years. Pipelines with High Consequence Areas need to be inspected every 5 years.	*Require more frequent inspections [5 years]*

Commenter **Gas Processors Association**

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

Commenter **Judy Skog**

I applaud your inclusion of all pipelines in the requirement to have inline integrity inspections. I would urge you to have that interval be 5 years. A lot can happen in 5 years (ask anyone who lives near Kalamazoo, Michigan)	*Require more frequent inspections [5 years]*

Commenter **Kathy Hollander**

Pipelines not covered by Integrity Management programs and those that lie outside of High Consequence areas should be inspected every five years, just like those inside HCAs . . . if significant corrosion is found, then every year thereafter.	*Require more frequent inspections [5 years; and more often (annually) if significant corrosion is found]*

Commenter **Offshore Operators Committee**

The proposed rule provides a ten-year cycle for assessments, but it does not specify when operators must perform the first assessment. The OOC requests that PHMSA follow past integrity management rules in the phase-in period. Specifically, the OOC requests an initial period of 3-4 years for thorough risk assessment/engineering analysis of all offshore assets and determination of what lines would require an integrity assessment. For implementation of assessments on those lines deemed to have threats that require a periodic integrity assessment the OOC requests 10 years for completion of the first assessments. Subsequent assessments would then occur once every ten years or as otherwise necessary to comply with the public safety timeframe. This reasonable approach would allow operators, tool suppliers and vendors to adequately plan for such a significant change.	*Recommend a phased approach to implementing assessments of non-HCA pipeline segments [Follow past IM rules in the phase-in period with 3-4 years for risk assessment/engineering analysis and 10 years for completion of the first assessments.]*

Commenter **Pipeline Safety Coalition**

PSC applauds the requirement for ILI inspection outside HCA's however, given the poor showing of the current IM program in HCA's (as noted by the Integrity Management of Gas Transmission Pipelines in High Consequence Areas, Safety Study SS-15/01, Washington, DC: National Transportation Safety Board, 20155) we question the determination of 10 year vs 5 year inspections. PSC recommends adherence to the 5 year inspection timeframe and integration of risk management assessment requirements of the IM program for increased pipeline safety.	*Require more frequent inspections [5 years]*

Commenter **Sharon Austry**

read your proposals and I don't understand why on earth you would increase the time between inspections from 5 to 10 years when they should be inspected every month and why you would wait up to 72 hours before you would investigate a leak. I think that there should be monitors on every well and alarms that go off like tornado warnings after every leak. It about time to put the safety of the public before the profits of the gas and oil industry.	*Require more frequent inspections [5 years]*

Commenter **St Croix River Association (SCRA)**

There is no rationale given for 10 years versus the current 5 years [for for periodic assessments of pipelines that are not already covered under the integrity management (IM) program requirements], and this only requires the inspection part of the IM program, not the risk assessment part. We recommend that inspections be required every 5 years and that the risk management requirements of the IM program be added.	*Require more frequent inspections [Recommend inspections for pipelines not already covered by the IM program every 5 years instead of 10.]*

Commenter **Texas Pipeline Association**

Section 195.416 as proposed is missing . . . A time period for completion of initial assessments on non-HCA pipelines	*Recommend a phased approach to implementing assessments of non-HCA pipeline segments [10-12 years]*
TPA would also urge PHMSA to revise proposed Section 195.416(b) to permit reassessment intervals to be based on sound engineering judgment and industry consensus standards based on the condition of the pipeline as revealed by the prior assessment, leak history of the pipeline, location and other risk factors.	*Allow flexible inspection frequency [Revise reassessment intervals so that they're based on engineering and industry strandards]*

Commenter **Tip of the Mitt Watershed Council**

We strongly support the proposal to require operators to assess non-High Consequence Area pipelines with an inline inspection (ILI) tool. However, we have concern with the timeframe for the inspections. We would recommend shortening the 10-year interval to a 5-year interval. Substantial changes in anomalies and pipeline integrity can happen within 5 years. A shorter interval between assessments would allow operators to catch anomalies in a timely manner decreasing risks of integrity-related failure.

Require more frequent inspections [5 years]

Commenter **Western Organization of Resource Councils**

The new requirement compelling pipelines outside of high consequence areas (HCAs) to be assessed mainly by inline inspection devices once every ten years is also an improvement. However, we urge that more frequent inline inspections be required, especially for the vast network of aging pipeline infrastructure across the nation. We believe that all pipelines should be assessed at least every five years to prevent leaks, spills and other accidents.

Require more frequent inspections [5 years]

Subissue **Risk factors**

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

Accordingly, the Associations recommend that PHMSA amend the regulatory language proposed in Section 195.416(c) to include additional language, indicated by the bolded text, as follows: "The assessment … must be performed with an in-line inspection tool or tools capable of detecting corrosion and or, if indicated as a threat by the historical data of the pipeline, deformation anomalies including dents, cracks, gouges, and grooves, unless an operator…" [p.11]

[Request that the assessment consider historical data in determining whether a particular feature is a therat]

Request that the assessment consider historical data in determining whether a particular feature is a threat

Subissue **Scope of applicability**

Commenter **American Gas Association (AGA)**

AGA also disagrees that expansion of IM assessments "would ensure prompt detection and remediation of corrosion and other deformation anomalies in all locations not just HCAs." Id.

Disagree that requirement will provide benefits [Unnecessary because of current actions of operatory to assess and address risks]

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

The Associations request that PHMSA clarify that it intends for the requirements articulated in this regulatory proposal to include transmission lines only. [p.11]

Clarify scope of pipelines to which the requirements would apply [recommend transmission lines only]

[re. Offshore piplines]: Much of the offshore pipeline mileage that is regulated by PHMSA is non-HCA mileage. Under the current language proposed by PHMSA, however, a majority of the offshore pipeline network would potentially be subject to an ILI assessment. Requiring ILI assessments for offshore pipelines would present particularly acute challenges due to factors such as heavy wall thickness (often over 1 inch), intense pressures at the seafloor, availability of space on platforms for accommodating longer smart tools, just to name a few. Projects that would normally be easily accomplished onshore (e.g., locating and retrieving a stuck pig) can become a highly complex and costly undertaking for an offshore pipeline. In addition, the limited number of vendors that currently have tools that can work under such extreme circumstances further compounds these
challenges. The technology does not currently exist to perform an ILI inspection for some offshore pipelines. [p.13]

The Associations request that PHMSA clarify in the final rulemaking that operators need not run assessments on idle or out of service pipelines. These lines pose no risk to the environment or the public and conducting inspections on these lines would divert resources from areas that more immediately require operator attention. [p.15]

Clarify scope of pipelines to which the requirements would apply

Commenter **Cook Inlet Regional Citizens Advisory Council (RCAC)**

The requirement for inline inspections of pipeline segments that are outside of HCAs and therefore not subject to IM requirements is an improvement over the current requirements. However, inline inspections conducted every 10 years will not afford the same level of ongoing safety management as a full IM program. The definition of HCA is limiting and does not necessarily incorporate all areas of concern to Cook Inlet RCAC member entities. The best approach to ensuring pipeline safety would be to have comprehensive IM requirements for all pipeline segments, regardless of their proximity to HCAs. If entire pipeline systems were required to implement IM programs, the corresponding safety benefits and oil spill risk reduction would be substantial.

Broaden applicability [Require regulation through the full suite of IM safety and prevention measures to all regulated pipelines]

Commenter **County of Santa Barbara**

However, because internal and external pipeline corrosion rates are highly dependent upon the chemical characteristics of the transported liquid and the location of the pipeline, the County suggests that these regulations require a more frequent annual inspection timeframe to account for such factors. We suggest that this annual inspection apply to hazardous liquids pipelines which are subject to IM program requirements, as well as to those that are not. Iinposing an annual inspection requirement on all pipelines will provide for a higher level of
environmental protection and serve to further limit pipeline spill incidents. In California, the recently
passed State Senate Bi11295 (SB 295) requires the State Fire Marshall to annually inspect all intrastate
pipelines. More frequent inspections are critical when assessment reports demonstrate accelerated
corrosion or other factors negatively affecting pipeline integrity. Despite a three year inline inspection
interval on Plains All American Pipelines' Line 901 (the pipeline involved in the May 2015 Refugio
oil spill), in-line inspections still failed to identify a fatal anomaly in the pipeline. T

Broaden applicability [Apply requirement to hazardous liquids pipelines subject and not subject to IM program requirements]

Commenter **Denbury Resources**

C02 pipelines are a distinct class of pipelines and have historically had a good safety record. Under 49 CFR 195.50, pipeline operators, including CO2 pipeline operators, are required to report accidents to the Department of Transportation. Since reporting began in the early 1990s, the federal database demonstrates that CO2 pipelines have had a "particularly good" safety record.	*Exempt lines with relatively lower risk [Exempt CO2 pipelines]*

Commenter **Enterprise Products Partners**

PHMSA explains in the preamble that it "is proposing to clarify, through the use of an explicit reference that the IM requirements apply to portions of "'pipelines' other than line pipe" to ensure that operators complete analyses of pipeline facilities (such as pump stations and breakout tanks) including implementation of any preventive and mitigative (P&M) measures. NPRM at 61615-61616. Enterprise agrees that this is an important step in the IM analysis for operators and supports the clarification. That said, the proposed revisions to Section 195.452(h)(1) fall short of providing the additional clarity that is warranted. [suggested language to mention periodic evaluations, information analysis, etc. and facilities]	*Clarify requirements applicable to pipeline facilities*
In the existing version of this section, operators are required to evaluate LF ERW and lap welded pipe, determine if they are susceptible to long seam failure, then run an applicable ILI if the pipe is found to be susceptible. In contrast, under the proposed revisions, operators would be required to run a long seam tool on all LF ERW, all lap welded pipe, all pipe with a seam factor <1.0 and all lap welded pipe deemed susceptible to longitudinal long seam failure. Since all lap weldedreference to "lap welded pipe" must be a typographical error. Enterprise believes that PHMSA only intended to add pipe with seam factor <1.0 to the existing list of pipe that must be evaluated and if deemed susceptible, a long seam ILI tool should be run. Otherwise, operators would be required to run a long seam ILI tool on all LF ERW pipe and all lap weld pipe regardless of the results of any susceptibility evaluations.	*Clarify applicability to lap welded pipe*

Commenter **Gas Processors Association**

PHMSA is proposing to establish essentially the same repair criteria as for those segments which could affect a HCA without identifying why it is believed this is a necessary step. Has PHMSA documented through its enforcement program that the current requirements in §195.401(b)(1) are unenforceable as written?	*Request documentation for why the same repair criteria is required for non-gathering lines as for those segments which could affect a HCA*
GPA would also like to know if PHMSA considers deferring assessments on Out-of-Service Idle (product evacuated, nitrogen blanketed) lines until preparation for return to service acceptable under this proposal? Under these conditions, there is no risk from a release. This would be consistent with policy established during implementation of the Integrity Management Program.	*Clarify applicability to Out-of-Service Idle lines [recommend deferral as acceptable]*
GPA requests PHMSA provide exceptions for short lines, e.g. less than 1 mile in length, that are contained within the operators facilities and pose no risk to the public. This would keep it consistent with the exceptions contained, currently and in the proposed modified §195.120(b).	*Exempt lines with relatively lower risk [Short lines (less than 1 mile in length) that are contained within operators facilities and pose no risk to the public]*

Subissue **Scope of requirements**

Commenter **Alliance for Great Lakes et al.**

We approve of PHMSA's proposal to require non-IM pipeline operators to perform pipeline assessments. However, the 10 year timeframe associated with the inspection mandate should be reduced to the 5-year standard applied to IM-pipelines. PHMSA should also propose a requirement and associated standards for risk assessment on non-IM pipelines.	*Require more frequent inspections [5-year standard instead of 10-year]*

We approve of PHMSA's proposal to require non-IM pipeline operators to perform pipeline assessments. However, the 10 year timeframe associated with the inspection mandate should be reduced to the 5-year standard applied to IM-pipelines. PHMSA should also propose a requirement and associated standards for risk assessment on non-IM pipelines.	*Require risk assessment on non-IM pipelines*

Commenter **American Gas Association (AGA)**

current regulations already require all threats on a pipeline, even those outside of HCAs, be considered to ensure that those threats do not exist within the HCA. Threats that exist outside of HCAs are evaluated and monitored using Preventative and Mitigative (P&M) measures should the threat be determined to be high risk to the pipeline.	*Requirement is duplicative/unecessary [Threats outside of HCAs are already considered through P&M measures]*
AGA supports the qualification of ILI vendors when performing covered tasks; however, AGA maintains that it is not common practice for personnel who may review data to have formal and defined operator qualifications. AGA strongly recommends that PHMSA not incorporate this requirement into pipeline safety regulations, as it would completely undermine the current process by which operators make integrity management decisions on their systems. In just one example, an individual at the operating company may review data from two different ILI vendors and compare the condition reports to determine if additional digs should be performed. The current proposed language for §195.416(d) – Data Analysis, would require operators to develop an Operator Qualification program for any personnel that make decisions relating to assessments, even if that person is being more conservative than the ILI vendor.	*Qualification for quality analysis [Supports qualifications of ILI vendors, but not those for operator personnel. The qualifications of individual reviewing ILI results should reflect common industry best practices]*

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

In its current form, the proposed regulatory language implies that operators must assess non-HCA pipelines for each of the enumerated anomalies regardless of whether threat indicators of those anomalies are present on the line. During the PHMSA-led webinar on December 15, an attendee posed a question to PHMSA staff requesting clarification on this very point. Specifically, the individual asked whether a tool capable of detecting a crack anomaly must be used during each assessment. [p.11]	*Allow consideration of risk factors [Provide more flexibility for requirements applicable to non-HCA pipelines]*

An operator would not be allowed to satisfy the assessment requirement by performing a hydrostatic test of the line, even if appropriate for assessing the safety of that line, unless it can demonstrate that the line is not capable of accommodating an ILI tool. Such a one-size-fits-all approach for non-HCA pipelines similarly departs from current HCA requirements to evaluate each pipeline and select an assessment method most appropriate for that pipeline. Therefore, the Associations request that the final rule make clear that operators may select the appropriate assessment method, just as they may with respect to the current HCA requirements. [p.12]

no criteria are articulated in the language of the proposed rule. PHMSA staff indicated informally that factors relating to the basic construction of the pipeline (e.g., sharp bends and elbows), would be sufficient to utilize an alternative test
method. Other operators asked follow-up questions relating to other factors that the agency would deem appropriate. Based on the staff answers, low flow in a pipeline would also be a circumstance warranting an alternative assessment methodology. [p.12]

Pipeline operators believe the approach of the current integrity management program for HCAs of tailoring assessment and inspection tools to the specific threats of the pipeline is both protective of safety and avoids unnecessarily burdening resources that could be used to protect pipeline safety elsewhere. API and AOPL request that PHMSA amend proposed Section 195.416(c) to allow operators to apply the inspection technology most appropriate to the conditions of the pipeline and provide for alternative testing techniques through processes consistent with current regulation of HCA areas. The amendment would allow operators to evaluate each pipeline and select an assessment method most appropriate to address the potential threats specific to that pipeline, if any. The Associations ask that PHMSA acknowledge in the final rulemaking that each of the assessment methods afforded to HCA segments in Section 195.452(c)(1)(i) may be utilized in addition to hydrostatic testing for all non-HCA lines, especially non-HCA gathering lines. [API-AOPL]

Allow use of various assessment methods [Allow for use of HT or other alternative assessment methodology for non-HCA lines]

Commenter **Congresswoman Lois Capps**

Regarding reporting requirements of inspection results, existing provisions require that sufficient condition information is submitted to the operator within 180 days and that PHMSA be notified if this timeline is not met, but there appears to be no requirement that primary inspection results and data are provided to PHMSA. If there is indeed no provision for transmission of inspection vendor reports to PHMSA prior to onsite inspections, there needs to be an additional requirement that the primary inspection report and data be transmitted to PHMSA at the same time as it is reported to the pipeline operator. This requirement would ensure that pipeline operators are adhering to mandatory inspection timelines and provide for an important verification that this activity is being appropriately conducted. In addition, inspection reports should be available to all interested stakeholders through the PHMSA website to improve transparency.

Require primary inspection results and data be provided to PHMSA

Regarding reporting requirements of inspection results, existing provisions require that sufficient condition information is submitted to the operator within 180 days and that PHMSA be notified if this timeline is not met, but there appears to be no requirement that primary inspection results and data are provided to PHMSA. If there is indeed no provision for transmission of inspection vendor reports to PHMSA prior to onsite inspections, there needs to be an additional requirement that the primary inspection report and data be transmitted to PHMSA at the same time as it is reported to the pipeline operator. This requirement would ensure that pipeline operators are adhering to mandatory inspection timelines and provide for an important verification that this activity is being appropriately conducted. In addition, inspection reports should be available to all interested stakeholders through the PHMSA website to improve transparency.	*Make inspection reports available to the public on PHMSA website*
While I agree that this must be addressed, the inspection alternative language (e.g., “alternative technologies would include hydrostatic pressure testing or appropriate forms of direct assessment”) could result in insufficient inspection along the entire pipeline. Alternative methods must account for inspection along the entire pipeline both inside and outside rather than relying on preconceived assumptions regarding probable anomalies. Language to clarify this intention is necessary to make the provision meaningful.	*Clarify that alternative methods must account for inspection along the entire pipeline both inside and outside*

Commenter **County of Santa Barbara**

However, because internal and external pipeline corrosion rates are highly dependent upon the chemical characteristics of the transported liquid and the location of the pipeline, the County suggests that these regulations require a more frequent annual inspection timeframe to account for such factors. We suggest that this annual inspection apply to hazardous liquids pipelines which are subject to IM program requirements, as well as to those that are not. Iinposing an annual inspection requirement on all pipelines will provide for a higher level of environmental protection and serve to further limit pipeline spill incidents. In California, the recently passed State Senate Bi11295 (SB 295) requires the State Fire Marshall to annually inspect all intrastate pipelines. More frequent inspections are critical when assessment reports demonstrate accelerated corrosion or other factors negatively affecting pipeline integrity. Despite a three year inline inspection interval on Plains All American Pipelines' Line 901 (the pipeline involved in the May 2015 Refugio oil spill), in-line inspections still failed to identify a fatal anomaly in the pipeline. T	*Require more frequent inspections [Annual]*

Commenter **Earthworks**

While operators may under limited circumstances employ other non-ILI technologies, direct assessments are only effective measures of pipeline integreity where the operator knows exactly where and what to assess. Firther since PHMSA proposes to gradually phase out pipelines incapable of accommodating ILI, PHMSA should maintain consistency within this proposed rule	*Limit use of certain assessment methods [Prohibit direct assessment as an alternative to ILI]*

Commenter **Energy Transfer Partners**

PHMSA also stated during the webinars that the ILI tools do not need to assess for corrosion and deformation anomalies, including dents, cracks, gouges, and grooves, but only for those deemed or confirmed by the operator to be a credible or active threat on the segment. PHMSA at that time also noted that ILI is not mandated, but that other technologies are allowed. However, both of those interpretations are problematic, as they are contrary to a plain reading of the proposed rule language. That language offers no alternative or relaxation of the required ILI capability based on risk or potentially active threats. And while there is a provision allowing the use of other technologies if the segment is not capable of accommodating an ILI tool, the requirement is that the alternative assessment method "will provide a substantially equivalent understanding of the condition of the pipeline." Other than direct visual inspection of the pipe steel surface, using corrosion measuring devices and performing ultrasonic and magnetic particle inspections, we are unaware of alternative methods that assess for corrosion, dents, cracks, gouges and grooves. So technically there is no alternative at all.	*Allow use of various assessment methods [Clarify that alternatives to ILI are options]*
This proposed section establishes a very strong PHMSA preference for in-line inspection ("ILI"). That preference was confirmed in recent webinars hosted by PHMSA to try to clarify certain aspects of this proposed rulemaking. In this regard, the assessment requirements for non-HCA segments are more stringent, prescriptive and demanding than the corresponding requirements for HCA segments. Commenter **Enterprise Products Partners**	*Resolve apparent higher stringency of non-HCA vs. HCA requirements*
Enterprise therefore respectfully requests that PHMSA's proposed assessment requirements for non-HCA pipelines be revised in the Final Rule to allow operators the latitude they have under current IM regulations to determine the actual threats to pipeline integrity present on a given segment and to tailor their integrity assessment program accordingly.	*Allow consideration of risk factors [Allow operators to tailor IM program to the threats to the pipeline on a segment basis.]*
The proposed rule would require notification to PHMSA (in addition to the justification of an alternative assessment method, described above) where a pipeline is incapable of accommodating an ILI tool. This requirement is inconsistent with the proposed changes to the equivalent provision at 195.452(c)(1)(i), which would allow assessment methods other than ILI—specifically, pressure testing, external corrosion direct assessment, or "other technology" that provides an equivalent understanding of the condition of line pipe—where ILI is impracticable on HCA segments, but does not require PHMSA notification. NPRM at 61641. PHMSA notification requirements for the planned use of hydrostatic testing (or other assessment technology) on non-HCA pipeline segments therefore place greater scrutiny on assessment methods used in non-HCAs, in a way that is inconsistent with the goal of prioritizing safety in HCAs.	*Require notification to PHMSA only when an operator chooses to use "other technology" outside of the three widely-accepted assessment methods specified in current IM regulations.*
the proposal to require assessments at least once every 10 years or "as otherwise necessary to ensure public safety" does not provide sufficient guidance to determine when a particular operator is required to assess non-HCA segments. The preamble provides no clarification on the intent of this proposed alternative timing requirement, including whether it would impart to the Agency discretionary authority to require additional assessments at intervals shorter than 10 years and, if so, what the criteria would be for determining that such assessments are "necessary to ensure public safety." Enterprise therefore requests that this requirement be replaced with language very similar to that in 49 C.F.R. Part 195.452(j)(3) as modified for the 120 month interval.	*Clarify the "as otherwise necessary to ensure public safety" guidance for assessment of non-HCA segments*

The proposal would require operators to run crack tools on every single assessment, regardless of whether there is a threat of cracking on a particular segment. NPRM at 61639 (proposing a new Part 195.416(c) that would require use of a tool or tools "capable of detecting corrosion and deformation anomalies, including dents, cracks gouges, and grooves") (emphasis added). While this proposed requirement mirrors the proposed change to assessment requirements for HCA pipelines, there are significant differences. NPRM at 61641 (proposing revision to Part 195.452(c)(1)(i) that would require operators to perform ILI assessments on HCA pipelines with a tool capable of detecting corrosion, and deformation anomalies "including dents, cracks (pipe body and weld seams), gouges and grooves" unless doing so is impracticable). Enterprise requests that the proposed Part 195.416(c) be clarified to state that crack tools are required only when there is an identified risk supporting their use, and that they are not necessary for every assessment.	*Clarify when crack tools are required for an assessment*

Commenter **Environmental Defense Center**

Third party verification of inspection reports must also be required. In the case of the Plains Pipeline oil spill, Plains reported corrosion of 45% in sections of the pipeline whereas an independent inspector found that corrosion was much more extensive (see attached PHMSA Amendment No. 1 to the Corrective Action Order), equating to a 80% corrosion rate. PHMSA's independent review of the Plains' ILI reports for Lines 901 and 903 found that anomalies were "under-called" (see attached PHMSA's Amendment No. 2 to the Corrective Action Order).	*Require third party verification of inspection reports*
The proposed rule, however, only requires inspections every ten years. As we saw with respect to the Plains All American Pipeline, inspection frequency is critical to detecting problems before a spill happens. In the case of the Plains oil pipeline, the inspection schedule had been reduced from five years to three years, and even that was inadequate to detect thepervasive corrosion throughout the pipeline system in time. (See attached PHMSA Corrective Action Orders that confirmed, after the fact, the significant corrosion that had gone undetected for at least 48 miles of pipeline.) As a result of the Plains pipeline spill, California law was amended to require annual inspections of all intrastate pipelines used for the transportation of hazardous or highly volatile liquid substances. California Government Code § 51015.1 (SB 295, Pipeline Safety: Inspections, enacted into law on October 8, 2015). Whether a pipeline travels intrastate or interstate should not matter in terms of the requirement to conduct regular and frequent inspections.	*Require more frequent inspections [Annual inspections for all federally-regulated hazardous liquid pipelines]*

Commenter **Gas Processors Association**

GPA questions why PHMSA has not taken the more reasonable approach as it is proposing in the modifications to § 195.452(c)(1)(i)? PHMSA and its state partners would still be able to evaluate the reasons an ILI was not used, but without the burden, on both regulators and industry and the delay created by the notification process.	*Recommend approach similar to proposed modifications to section 195.452(c)(1)(i) instead of notification process*
In the RIA, PHMSA assumed that new construction pipelines would not incur any assessment costs in the first ten years since they would be Hydro Tested post construction. However, as written, PHMSA is proposing to require prior notification to use any assessment method other than ILI. Through literal interpretation of the proposal, an operator would submit prior notice during the construction of a pipeline that it plans to use the post construction Hydro Test as a "qualifying assessment" as well. Is this the process PHMSA envisions for an operator to be compliant without conducting duplicative tests? Currently, we see no recognition of this test as sufficing for an assessment without notification within the proposed rule. GPA would like PHMSA to provide clarification on this issue.	*Clarify prior notification requirement for any method other than ILI in the case of new pipelines.*

PHMSA is proposing to include performance language requiring persons performing the data analysis of non-IM assessments to be “qualified by knowledge, training, and experience.” API-AOPL and many other commenters responding to questions posed in the ANPRM supported the incorporation by reference of American Society of Nondestructive Testing (ASNT) ILI PQ to satisfy the need to assure quality data analysis. In this preamble, PHMSA has stated “PHMSA is proposing by a separate rulemaking via incorporation by reference available industry consensus standards for performing assessments of pipelines using ILI tools, internal corrosion direct assessment, and stress corrosion cracking direct assessment.”
We encourage PHMSA to include ASNT ILI PQ as part of that rulemaking while deferring action on the current proposal. Operators typically do not have the expertise to judge vendors on their proprietary technologies.

Qualification for quality analysis [Recommends including American Society of Nondestructive Testings ILI PQ to satisfy the need to assure quality data analysis]

Commenter **General Electric Oil & Gas**

GE supports the requirement for operators to carry out ILI in non-HCA areas to assess for mechanical damage and associated metal loss features. Operators already obtain inspection data for pipelines passing through HCAs that have pig traps beyond the HCA< and the re-run those segments at 5-year intervals. We believe PHMSA should accommodate the acquisition of that data - already captured - from these non-HCA pipeline sections.

Accomodate the acquisition of already captured data for non-HCA sections

Commenter **Janet Alderton**

I approve of the requirement to assess the integrity of hazardous materials pipelines outside of High Consequence Areas. The requirements state that such an inspection be "at least every ten years" and that any problems be corrected in "no longer than 180 days after the inspection." The intervals of at least every ten years and no longer than 180 days are too long. Would this new regulation have prevented the May 19, 2015 Refugio spill into the marine waters near Santa Barbara? The answer is that it is unlikely that testing every 10 years would have been frequent enough. For the Refugio spill, a smart pig test had been run two weeks before the spill, but the data had not been analyzed at the time of the spill. After the data were analyzed, the degree of actual corrosion was much greater than shown by the smart pigging.

Require more frequent inspections [Require testing more frequently than every 10 years]

Commenter **National Association of Pipeline Safety Representatives (NAPSR)**

NAPSR feels that the addition of an assessment requirement for hazardous liquid pipelines not under the Integrity Management rule will help to increase pipeline safety and reduce leak-related potential environmental impact for those pipelines not in High Consequence Areas. NAPSR also feels that PHMSA should allow pressure testing in lieu of ILI. Pressure testing may be more economical for operators w/ legacy piping w/ no material records or operating and maintenance records. NAPSR suggests the following addition to 195.416 (c)(i): "..and that the use of an alternative assessment method will provide a substantially equivalent understanding of the condition of the pipeline; or (ii) the operator is able to conduct a pressure test in lieu of other assessment methods to reestablish the MAOP/MOP of the pipeline;"

Allow use of various assessment methods [Allow pressure testing in lieu of ILI]

Commenter **National Transportation Safety Board**

In our January 2015 gas transmission pipeline study, Integrity Management of Gas Transmission Pipelines in High Consequence Areas, we concluded that relying only on direct assessment as a primary avenue for IM is ineffective.3 Our report noted that direct assessment is used to evaluate pipeline corrosion threats only. Unlike ILI and pressure tests, in which the integrity of the entire pipeline segment is examined, direct assessment methods (including external-corrosion direct assessment, internal-corrosion direct assessment, and stress corrosion cracking-direct assessment), assess only the integrity of selected pipe areas where the operator suspects a problem. Therefore, direct assessment provides information only about threats that the operator is specifically looking for at locations where the threats are suspected. Therefore, the NTSB asks that PHMSA harmonize the gas and liquid regulations to the maximum extent practicable. Furthermore, PHMSA should include a strong cautionary statement to stress that direct assessment is an ineffective alternative technology for IM when applying the 10-year assessment requirement for the integrity of an entire pipeline. The owner/operator IM program should encompass a broad range of available IM technologies including, but not limited to, ILI, magnetic flux leakage, ultrasonic testing, and tests directed at determining the integrity of the pipe coating.	*Limit use of certain assessment methods [Harmonize the gas and liquid regulations and include a strong cautionary statement regarding the ineffectiveness of direct assessment]*

Commenter **Pipeline Safety Trust**

Integrity Management is based on risk assessment and then an inspection system that identifies and mitigates of the identified risks [suggested language]	*Allow consideration of risk factors [The requirements as written are missing key elements of IM: threat identification or risk assessment]*
Integrity Management is based on risk assessment and then an inspection system that identifies and mitigates of the identified risks	*Require more frequent inspections [Provide justification for 10-year inspection timeline; Recommend the existing 5-year timeframe]*
some pipeline operators currently turn of inspection tool capacity when outside HCAs . . . If the ILI tool is equipped with the capacity to look for crack defects, that inspection capacity should continue once outside and HCA area. [provided suggested language]	*Broaden requirements [Tools with additional capacities should not be turned off outside of HCAs]*

Commenter **Texas Pipeline Association**

Evaluations of assessments often lead to a determinations of the need for additional field work to confirm assessment results. Such work must be scheduled and performed to enable discovery of a condition. Establishing a deadline for discovery of condition on non-HCA pipelines that is identical to the deadline for HCA pipelines will effectively diminish the resources available to focus on higher risk HCAs	*Resolve apparent higher stringency of non-HCA vs. HCA requirements [Revise 195.416(e) to allow 270-day period following assessment for the discovery of condition on non-HCA pipelines]*
As proposed, section 195.416 would require justification for the use of any assessment methodology other than inline inspection. This is not a requirement for pipeline assessments in HCAs.	*Allow use of various assessment methods [Revise to permit assessment by any of the assessment methodologies currently allowed under IM]*

Commenter **Tip of the Mitt Watershed Council**

In addition, we have concern that direct assessment is considered an effective alternative technology that can be utilized if a pipeline is not capable of accommodating an ILI tool. The National Transportation Study Board concluded in a 2015 study, "Integrity Management of Gas Transmission Pipelines in High Consequence Areas," that there are many limitations to direct assessment and it is an ineffective assessment method. We would recommend that direct assessment not be a recommended or approved alternative technology to assess non-HCA pipeline segments.	*Limit use of certain assessment methods [Prohibit direct assessment as an alternative to ILI]*

Issue ID **1.5** **Repair criteria**

Subissue **Costs**

Commenter **Independent Petroleum Association of America**

The Proposed Rules mandate more immediate repairs to pipelines affected by certain dents as well as a more conservative pressure repair threshold. PHMSA rightly predicts that this requirement will cause more pipeline sections to require immediate repair. However, the Proposed Rules do not address if resources exist to make the additional repairs that would be required. Further, the increased conservatism in repair requirements would impact regulated gathering lines. However, PHMSA has not demonstrated a nexus between an existing risk and the more conservative repair requirements that justify the potential costs.

PHMSA has not demonstrated a nexus between an existing risk and the repair requirements (for certain dents and more conservative repair threshold) to justify the potential costs and did not address availability of resources to make additional repairs.

Subissue **Implementation schedule**

Commenter **Gas Processors Association**

PHMSA is proposing to establish essentially the same repair criteria as for those segments which could affect a HCA without identifying why it is believed this is a necessary step. Has PHMSA documented through its enforcement program that the current requirements in §195.401(b)(1) are unenforceable as written? At a minimum, PHMSA should revise the “18 month” timeframe to read two years to allow for scheduling around unfavorable weather conditions which can be detrimental to the repair process and to enable them to be included in budget processes.

Lenghten the deadline for repairs [Revise the 18-month timeframe to 2 years to allow for scheduling around unfavorable weather conditions for the repair criteria]

Commenter **St Croix River Association (SCRA)**

However, this section also changes the time available to operators to make repairs for anything other than ‘immediate’ repair conditions by eliminating the 60- and 180-day repair categories and replacing those together with a 270-day repair category, and adding an 18-month repair category for pipelines not subject to IM, i.e. those not affecting HCAs. We’re still analyzing the more technical aspects of the listed repair conditions. Furthermore the proposal does not change the threshold for corrosion-based ‘immediate repairs’ even though recent failures have shown that waiting until corrosion metal loss grows to 80% of the pipeline wall to require an ‘immediate repair’ is not an appropriate threshold due to the speed of corrosion growth.

Shorten the deadline for repairs [270 days is too long]

Subissue **Repair criteria**

Commenter **Accufacts**

Given the cycle of baseline and additional reassessments required over the past decade for IM, many construction related anomalies of concern should have been addressed within HCAs. The proposed repair criteria and timing changes in the NPRM appear “workable” provided that PHMSA prescriptively define the equation and certain values utilized to simply calculate burst pressure in regulation. While this may seem trivial, it should be remembered that some pipeline operators that have experienced pipeline ruptures have been rather creative in trying to avoid IM regulatory intent. Given the importance of the safety factor being relied on for immediate repairs via the calculated burst pressure equation to 110 percent MOP, certain parameter values utilized in this simple calculation should be defined and incorporated into the regulation, and not left to interpretation.

Define the equation and certain valves utilized to calculate burst pressure

Commenter **Alliance for Great Lakes et al.**

We concur with PHMSA's expansion of the conditions that require immediate repair and its application of the new repair rule to non-IM pipelines. Nevertheless, we urge PHMSA to reduce the 80% corrosion-loss threshold to better prevent pipeline spills like the 2015 Santa Barbara, California oil spill, which was caused by corrosion.	*Set a more stringent repair standard [Reduce the corrosion-loss threshold]*
PHMSA should also establish standards for the prevention, detection, and remediation of "significant stress corrosion cracking" and stress corrosion cracking ("SCC") generally. PHMSA should require corrosion prevention measures for gathering lines. PHMSA should not wait to prescribe ILI standards in a separate rulemaking process.	*Establish standard for the prevention, detection, and remediation of SSCC and SCC*

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

API and AOPL suggest PHMSA strengthen the immediate repair criteria by adding a repair condition for likely crack anomalies greater than 70% of nominal wall thickness. This change would reflect the latest industry recommendations for repairing crack anomalies. API and AOPL also recommend PHMSA include criteria ensuring consideration of both metal loss features associated with plastic collapse and cracking that is considered a fracture mechanics feature.	*Include criteria ensuring consideration of both metal loss features associated with plastic collapse and cracking that is considered a fracture mechanics feature*
API and AOPL suggest PHMSA strengthen the immediate repair criteria by adding a repair condition for likely crack anomalies greater than 70% of nominal wall thickness. This change would reflect the latest industry recommendations for repairing crack anomalies. API and AOPL also recommend PHMSA include criteria ensuring consideration of both metal loss features associated with plastic collapse and cracking that is considered a fracture mechanics feature.	*Add repair condition for crack anomalies >70% wall thickness as immediate repair criteria/thresholds*
API and AOPL strongly urge PHMSA to address confusing language in paragraph (vii) which reads: "A potential crack indication that when excavated is determined to be a crack." This wording would create the impossible scenario of requiring operators to excavate a potential crack in order to determine whether they should excavate that potential crack. Written as such, the criterion is irrelevant to ILI response and provides no guidance or risk reduction. API and AOPL propose a measurable and detectable criterion of "a likely or possible crack with depth greater than 50% of nominal wall." [p.20]	*Clarify when excavation is needed to confirm potential crack in favor of crack criterion measurable/detectable by ILI*
API and AOPL recommend PHMSA include a "Scheduled Conditions" repair condition for non-HCA lines, with only one provision in this criterion. The Associations' proposed language is designed to mitigate the potential for pressure-limiting, immediate features before the next ILI is conducted. API and AOPL propose a new 49 C.F.R. 195.422(d)(4) to read as follows... [p.21]	*Modify repair conditions for non-HCA lines [Language provided]*
API and AOPL also propose changes to repair conditions for HCA lines in 49 C.F.R. 195.452 based on the rationale behind the modifications to the proposed non-HCA repair criteria in Section 195.422. The Associations recognize that, in HCA areas, repairs need to be made in 270 days, as opposed to 18 months.	*Modify repair conditions for non-HCA lines [Language provided]*
API and AOPL suggest PHMSA strengthen the immediate repair criteria by adding a repair condition for likely crack anomalies greater than 70% of nominal wall thickness. This change would reflect the latest industry recommendations for repairing crack anomalies. API and AOPL also recommend PHMSA include criteria ensuring consideration of both metal loss features associated with plastic collapse and cracking that is considered a fracture mechanics feature.	*Set a more stringent repair standard [Recommends PHMSA strengthen the immediate repair criteria by adding a repair condition for likely crack anomalies greater than 70% of nominal wall thickness.]*

Commenter **Enterprise Products Partners**

PHMSA's NPRM proposes an additional criterion for integrity management 270 day conditions, including corrosion of or along a longitudinal seam weld. This criterion was intended to address the same threat covered by the proposed immediate condition for SSWC. For that reason, Enterprise recommends that PHMSA delete this proposed requirement as duplicative and unnecessary.	*Requirement is duplicative/unecessary [Inclusion of longitudinal seam weld is duplicative.]*

This requirement does not allow operators the flexibility to determine the severity of the reported metal loss indication and its potential impact on the integrity of the pipeline. There will be many cases where the ILI data will clearly indicate that the metal loss is incidental and does not contribute to higher levels of stress in the pipe. As proposed, this requirement would require operators to excavate and repair many indications whose ILI data analysis and in-the-ditch data evaluation clearly demonstrates that the pipe defect did not present a pipeline integrity threat. [suggested language: any dent (regardless of o'clock position) on the pipeline that has any indication of cracking, gouging or other metal loss not confirmed to be corrosion.]

Refine repair criterion for dents

Commenter **League of Women Voters of California**

The pipeline at Refugio had been pigged two weeks earlier; preliminary assessment was a 45% metal loss due to corrosion. The actual loss, as measured after the spill, was 80% (the pipeline thickness was reduced to 1/16"). So requiring instant repairs at 80% loss is far too late for any preventive action.

Set a more stringent repair standard [Instant repairs at 80% loss is too late for preventive action]

Commenter **Pipeline Safety Trust**

We are also concerned about the newly proposed timetables for repair. We acknowledge the reasoned evidence given the new 270-day condition, and the elimination of the 60- and 180-day condition. However we did not see any evidence given for the 18-month and 'reasonable' timeframes added for repairing pipelines outside of HCAs . . . Because of the additional time allowed to address top- and bottom-side dents on the pipeline areas affecting HCAs, we suggest that those debt thresholds be changes accordingly

Set a more stringent repair standard [Recommend change in dent thresholds (lower) because of length of 18-month timeline]

It does not seem to take into consideration pipeline failures that have occurred in the past few years that demonstrate the speed at which corrosion can gros and lead to pipeline failures

Set a more stringent repair standard [Recommend more stringent repair criteria based on recent failures (60% for immediate repairs, and 30% for longer-term repairs)]

Commenter **St Croix River Association (SCRA)**

Modification of the IM repair criteria and application of those criteria to any pipeline where the operator has identified repair conditions . . . changes the time available to operators to make repairs for anything other than ‘immediate’ repair conditions by eliminating the 60- and 180-day repair categories and replacing those together with a 270-day repair category, and adding an 18-month repair category for pipelines not subject to IM, i.e. those not affecting HCAs. . . . the proposal does not change the threshold for corrosion-based ‘immediate repairs’ even though recent failures have shown that waiting until corrosion metal loss grows to 80% of the pipeline wall to require an ‘immediate repair’ is not an appropriate threshold due to the speed of corrosion growth.

Set a more stringent repair standard [Set a more stringent standard for the amount of metal that triggers "immediate repair"]

However, this section also changes the time available to operators to make repairs for anything other than ‘immediate’ repair conditions by eliminating the 60- and 180-day repair categories and replacing those together with a 270-day repair category, and adding an 18-month repair category for pipelines not subject to IM, i.e. those not affecting HCAs. We’re still analyzing the more technical aspects of the listed repair conditions. Furthermore the proposal does not change the threshold for corrosion-based ‘immediate repairs’ even though recent failures have shown that waiting until corrosion metal loss grows to 80% of the pipeline wall to require an ‘immediate repair’ is not an appropriate threshold due to the speed of corrosion growth.
 We have concern regarding the changes in the time frames allowed for repairs.
 We support a stronger standard for the amount of metal loss that triggers ‘immediate repair.’

Standard for allowable metal loss triggering immediate repairs should be more stringent.

Subissue **Repair evaluation methods**

Commenter **American Gas Association (AGA)**

AGA believes that current ILI tools do not provide sufficient information to operators to be able to apply the proposed definition [of Significant Stress corrosion cracking]. In order to truly understand both the depth of the wall thickness and the total interacting length, the pipeline would need to be excavated and directly examined and an attempt to remediate the condition would need to be made by removing the damaged metal through grinding - a process similar to that used to remediate arc burns from welding. Certain steps are necessary to locate SCC, including removing any disbonded coating found during direct examination, and any area of corrosion found must be closely examined. Additionally, there is still limited experience by ILI vendors with SCC tool data analysis.

Revise definition of Significant Stress corrosion cracking [Proposed definition is inappropriate as it is applied to immediate repair conditions because ILI tools do not provide sufficient information to apply the proposed definition]

Commenter **Pipeline Safety Trust**

Requirement that the operator knows what type of pipe is in the ground and set the maxmum operating pressure (MOP) approriately, or has tested the pipe with an appropriate hydrotest to demonstrate a safe MOP

Set additional requirement that MOP be set appropriately for the type of pipe in the ground

Subissue **Repair timing**

Commenter **Alliance for Great Lakes et al.**

We further disagree with the decision to replace the 60-day and 180-day repair categories with a 270-day repair category for nonimmediate repairs.46 While the 270-day timeframe may have been created to ease the administrative burden on pipeline operators given PHMSA's expansion of the conditions which require immediate repair, some of the non-immediate repair conditions are still serious enough to warrant quicker action. For instance, the proposed regulation categorizes "an area of general corrosion with a predicted metal loss greater than 50% of nominal wall" and "corrosion of or along a longitudinal seam weld" as 270-day repairs. We urge PHMSA to maintain a 180-day repair timeframe for all repairs that are not classified as immediate.

Shorten the deadline for repairs [Maintain a 180-day repair timeframe]

Commenter **American Gas Association (AGA)**

in the event that a non-HCA area is assessed during the same assessment as an HCA and immediate repair conditions are found on both segments of pipe, AGA members will prioritize the immediate condition on the HCA segment before the immediate repair condition on the non-HCA pipe segment. AGA encourages PHMSA to incorporate this logical practice if a similar proposal is including in a rulemaking that would apply to natural gas transmission pipelines and believes PHMSA should revise the proposed regulations to recognize this type of prioritization of HCA and non-HCA repairs.

Allow for prioritization of repair of HCA segments over non-HCA segments

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

API and AOPL also recommend PHMSA adopt an additional 18-month repair condition on dents with corrosion. The current generation of ILI tools used to identify metal loss will frequently identify shallow, non-injurious metal loss associated with the manufacturing process of the pipe. Grinding to remove burrs for thin film coating is an example. API and AOPL recommend usage of industry recognized engineering analysis to show an anomaly poses minimal risk to pipeline integrity. [p.20]

Specify an additional 18-month repair condition on dents with corrosion

There is also a concern about timing and response to anomalies located offshore. Repair of offshore lines can take anywhere from one month to well over a year depending on the type of repair and permitting that might be involved. For example, clamps used to repair offshore lines are special order items that have a long lead time and while a company might have some clamps in storage, if those available are not the right type, or if there are multiple anomalies, it will take months to get the proper equipment. In addition, each repair can cost a minimum of $500,000 and if a cutout is required this will be a major project that could cost as much as $10 million. Because of the difficulty of some of these repairs, it is requested that extra time be allowed for these repairs and that room for engineering judgment be included in the decision of what anomalies to repair.	*Lenghten the deadline for repairs [More time needs to be provided to address repairs in offshore pipelines (no time proposed)]*
Commenter **County of Santa Barbara**	
The Notice of Proposed Rulemaking does not provide an explanation for why the 60- day and 180-day repair categories are proposed to be extended to 270-days. We suggest that the 180- day repair category remain in place of the proposed 270-day repair category to ensure that pipeline repairs are conducted in a timely manner.	*Shorten the deadline for repairs [Maintain a 180-day repair timeframe]*
Commenter **Energy Transfer Partners**	
ETP supports the elimination of the 60-day and 180-day criteria. However, absent compelling data and analyses to the contrary, the proposed 270-day and 18-month criteria, while more manageable, appear to be similarly arbitrary. ETP suggests, again absent data and analyses to the contrary, that these instead be 1-year and 2-year criteria, thus enabling operators to plan, budget and schedule these actions in a more orderly and efficient manner.	*Lenghten the deadline for repairs [1-year and 2-year criteria]*
Commenter **Enterprise Products Partners**	
This requirement does not allow operators the flexibility to determine the severity of the reported metal loss indication and its potential impact on the integrity of the pipeline. There will be many cases where the ILI data will clearly indicate that the metal loss is incidental and does not contribute to higher levels of stress in the pipe. As proposed, this requirement would require operators to excavate and repair many indications whose ILI data analysis and in-the-ditch data evaluation clearly demonstrates that the pipe defect did not present a pipeline integrity threat. [suggested language: Any dent (regardless of o'clock position) on the pipeline with corroded areas deeper than 20% of the nominal wall thickness or where an engineering analysis indicates a reduction in the safe operating pressure of the dented area]	*Add a 270-day condition to 195.452(h)(4)(ii) with 20% threshold for dents*
Commenter **Environmental Defense Center**	
However, we oppose the proposal to extend the timeframe for repairs from 60 and 180 days to 270 days.	*Shorten the deadline for repairs [Maintain a 180-day repair timeframe]*
Commenter **Kathy Hollander**	
Even for pipes outside of the HCA area, I do not support the elimination of the 60 and 180 day repair category, since corrosion in the steel pipes can grow so rapidly.	*Shorten the deadline for repairs [Maintain existing repair timeframes]*
Commenter **Pipeline Safety Coalition**	

Given the national influx of hazardous liquid lines, the numbers of incidences the nation has experienced in recent years and the growing confluence of pipes to people, any consideration of reducing or eliminating repair categories at this time would seem inappropriate. Given our previous concerns regarding HCAs, we specifically have concerns about the changes in the time frames allowed for repairs and the standards for metal loss that trigger those repairs.	*Shorten the deadline for repairs*

Commenter **Spectra Energy Partners**

SEP's experience is that virtually all bottom-side dent with metal loss features are from original construction or from pipe settlement during a short period of time following construction, and likely have been present for years or decades. As in-line inspection tools have improved, they are better able to identify minor metal loss features, typically less than 10% deep, inside dents that were identified as plain dents by the previous in-line inspection. In these cases, it is obvious that the dent with metal loss feature is not new, and does not warrant an immediate response. As a result, classifying all bottom-side dent with metal loss features will result in unwarranted pressure reductions and service interruptions. SEP recommends the final rule include a 60-day response criterion for response to bottomside dent with metal loss indications. SEP believes this will result in a more practicable requirement with no reduction in pipeline safety.	*Include a 60-day response criterion for response to bottom-side dent with metal loss indications*

Commenter **St Croix River Association (SCRA)**

Modification of the IM repair criteria and application of those criteria to any pipeline where the operator has identified repair conditions . . . changes the time available to operators to make repairs for anything other than 'immediate' repair conditions by eliminating the 60- and 180-day repair categories and replacing those together with a 270-day repair category, and adding an 18-month repair category for pipelines not subject to IM, i.e. those not affecting HCAs. . . . the proposal does not change the threshold for corrosion-based 'immediate repairs' even though recent failures have shown that waiting until corrosion metal loss grows to 80% of the pipeline wall to require an 'immediate repair' is not an appropriate threshold due to the speed of corrosion growth.	*Shorthen the deadline for repairs*

Subissue **Scope of applicability**

Commenter **Earthworks**

Hazardous liquid pipelines that could affect HCAs receive additional IM protections.	*Expand IM requirements to all hazardous liquids pipelines under the agency's authority*

Commenter **Enterprise Products Partners**

As proposed, the rule "applies to pipelines that are not subject to the integrity management requirements in 195.452." Id. (emphasis added). This could inadvertently be misinterpreted to exclude those segments of pipelines covered by 195.452 but have been determined not to have the potential to impact HCAs from the proposed repair criteria. While these non-HCA "could affect" pipelines are subject to the IM rules, they are not subject to the repair criteria under IMP. [suggested language: clarifies that the section applies to pipelines not subject to IM in 195.452 and thise determined not to have the potential to impact HCAs]	*Clarify the application to pipelines under 1952.452*

Commenter **Western Refining**

The rulemaking proposes to require that in the event of the occurrence of an event that requires immediate repairs pursuant to 195.422(d)(1), that the operator reduce the operating pressure of the affected pipeline using a suitable and safe operating pressure. This blanket requirement to reduce pressure could be impractical for Western Refining, given that certain segments of Western Refining's pipelines already operate at a relatively low operating pressure. If further pressure reduction is mandated as per the proposed rule, this would effectively cease operations of these low pressure pipeline segments resulting in a detrimental impact on refinery crude supply to the Southwestern United States. As a result, Western Refining recommends that PHMSA exempt pipeline segments that normally operate at a low pressure from the pressure reduction requirement.	*Exempt lines with relatively lower risk [Exempt pipeline segments with low operating pressures from the requirement that pressure be reduced in the event of an incident requiring "immediate" repairs]*

Subissue **Scope of requirements**

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

API and AOPL recommend that PHMSA repair conditions reflect advances in understanding metallurgy and fracture mechanics. In regards to calculating a predicted burst pressure for the purposes of determining remaining strength, selection of a suitable calculation method depends on several factors, including the failure mode of the anomaly. PHMSA should expand appropriate calculation methods to include, but not limited to... [p.16]	*Incorporate industry recognized evaluation methods to calculate remaining strength of pipe.*
The application of clear criteria, the latest ILI capabilities, and understanding of remaining strength characteristics and fracture mechanics renders PHMSA's proposal requiring immediate repair of "any indication" of "significant" stress corrosion cracking (SCC) or selective seam weld corrosion (SSWC) unnecessary. API and AOPL agree with PHMSA's desire to ensure operators are appropriately mitigating the threat of SSWC or SCC. However, a requirement to immediately repair any indication of this type of these threats is overly broad and wasteful.[p.18]	*SCC and SSWC immediate repair criteria are unecessary given understanding of remaining strenght and fracture mechanics*
recommend that SCC reporting be considered for inclusion in the annual report.[p.18]	*SCC should be reported in annual report*
API and AOPL are concerned PHMSA's proposed criterion in paragraph 49 CFR 195.422(d)(3)(iv) for remaining strength of pipe at an anomaly less than the maximum operating pressure at that location presents a flawed logic, as an equivalent criteria of deriving a similar response from design factors in the natural gas pipeline regulations would not be feasible. Also, a more appropriate equivalence to a proof hydro-static test would lead to the proposed response criteria of a burst pressure less than 1.25 times the maximum operating pressure at the location of the anomaly. Finally, modifications need to be made to generalize this criterion to both metal loss and cracking. Given that SSWC is otherwise addressed within the proposed criteria API and AOPL believe that there remains no basis for a criteria regarding corrosion that is coincidentally of or along a seam weld. [p.20]	*Argues that there is no basis for a criteria regarding corrosion that is coincidentally of or along a seam weld since SSWC is addressed within proposed criteria*

API and AOPL are also concerned about the future interpretation of Section 195.422 beyond non-HCA transmission lines to gravity and gathering lines located offshore. PHMSA could address the Associations' concerns by adding the following language at the end of Section 195.422(a): "This section does not apply to gravity or gathering lines."	*Exempt lines with relatively lower risk [Non-HCA criteria should apply only to non-HCA transmission lines (not gravity or gathering lines located offshore)]*

Commenter **Enterprise Products Partners**

Enterprise recommends expanding (or clarifying) the application of the criteria in 195.422(d)(1)(ii) and 195.452(h)(4)(i)(B) to include SSWC. In addition to the existing referenced metal loss remaining strength formulae, acceptable methods for predicting failure pressure of SSWC could be included. Likewise, the criteria in 195.422(d)(3)(iv) and 195.452(h)(4)(ii)(D) should also be similarly expanded. These changes would apply the same safety margins against SSWC failure that are proposed for corrosion. The existing proposed clarifications in 195.416(d) and 195.452(c)(1)(i)(A) on how to treat uncertainties in reported ILI results are applicable where SSWC is suspected. Instead, these sections could specify that fitness for purpose calculation methods for cracks outlined in the upcoming API RP 1176 be used and that these calculations require the consideration of additional ILI tool tolerance that comes with measuring SSWC from ILI data, conservative assumptions about pipe material properties, and conservative assumptions about SSWC growth rate (in the 270-day condition criterion). Treating these indications as potential cracks is a conservative approach that strikes a better balance between making sure injurious SSWC is addressed promptly and the overly broad approach of repairing everything as an immediate regardless of severity.	*Clarify the application of the repair criteria to SSWC*

Commenter **Environmental Defense Center**

The rule should also identify immediate shutdown and repair criteria for certain conditions such as significant corrosion on the line.	*Require immediate shutdown and repair criteria for certain conditions, such as significant corrosion*

Commenter **Pipeline Safety Trust**

the existing section 195.422 contains language that is applicable to ALL pipelines, not just those outside of HCAs. Changing the scope of this section without adding the relevant existing language back into section 195.452 removes important code language regarding popeline repairs. [suggested language].	*Maintain the code language implications of section 195.452 (following changes to 195.422)*

Issue ID **1.6** **Expanded use of leak detection systems**

Subissue **Costs**

Commenter **Gas Processors Association**

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

Costs are understated [PHMSA needs to account for costs for pipelines without systems in place, and for training component.]

Subissue **Implementation schedule**

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

API and AOPL ask that PHMSA provide an implementation timeline so that operators have clarity on when pipelines should be updated with some form of leak detection system. Neither the NPRM language nor the proposed regulatory text references an implementation period. As it is critical for operators to understand the timeframe in which they must comply, API and AOPL request that PHMSA adopt a minimum implementation period of five years so that operators have sufficient time and resources to comply with the proposed rules. [p.26]

Provide phase-in period for implementation [5 years]

Commenter **Energy Transfer Partners**

Now the applicability appears to be all single-phase hazardous liquid pipelines, including previously unregulated gathering lines. For many operators, this may be a significant undertaking. PHMSA has provided no indication of a phase-in process or timetable. As written, it could be construed as in effect as of the date of the Final Rule, making many operators immediately out of compliance. PHMSA should specifically state a phase-in timetable to achieve compliance with this rule that allows all operators sufficient time to make determinations of need and appropriate systems, budget for those systems, order them, and receive, install and test them. This is likely to require a few to several years.

Provide phase-in period for implementation [Request a "reasonable and achievable" implementation schedule]

Commenter **Gas Processors Association**

GPA urges PHMSA to establish a seven (7) year installation and implementation timeframe. This should provide time to conduct system evaluation for use in leak detection system design, procurement, installation, testing, and training. [p.9]

Provide phase-in period for implementation [Recommends implementation schedule that reflects current systems on pipelines. 7-year installation and implementation time frame for leak detection systems for non-gathering lines]

Commenter **National Transportation Safety Board**

We agree with and fully support your proposal to require leak detection in all new hazardous liquid pipelines; however, the proposal fails to address how this requirement would be phased in to account for pipelines that would already be under construction. We strongly urge PHMSA to include language that specifies a distinct trigger date for leak detection implementation on pipelines that would have already started construction but would not yet be operational when the new regulation becomes effective.

Provide phase-in period for implementation [Address leak detection implementation for pipelines under construction]

Commenter **Texas Pipeline Association**

As written, Proposed Sections 195.134 and 195.444 require all new and existing hazardous liquid pipelines to have leak detection systems that meet the requirements of Section 195.444. However, neither Section contains any time Period for existing systems presently without leak detection systems to be retrofitted. It is unclear to TPA how many miles of rural hazardous liquid gathering pipelines will need to be retrofitted with leak detection systems or with components to permit them to function with operators’existing leak detection systems. Allowing adequate time for retrofitting may be sufficent to balance costs and benefits, but this is an issue that is whorthy of further consideration by PHMSA.	*Provide phase-in period for implementation [there is no implementation period for retroffiting existing lines, making it difficult to assess feasibility, costs, and benefits]*

Subissue **Other**

Commenter **Independent Petroleum Association of America**

While PHMSA has published the Report addressing leak detection systems, the Proposed Rules clearly indicate that the Report did not satisfy the mandate of H.R. 2845 and thus PHMSA cannot proceed with changes regarding leak detection systems.	*PHMSA should not proceed with expanded use of leak detection systems because it has not done an analysis of the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems.*

Subissue **Scope of applicability**

Commenter **Congresswoman Lois Capps**

Clearer language is necessary in describing the minimum standard for leak detection systems and clarification of the incorporation of leak detection systems in pipelines under construction but not yet completed.	*Clarify application to pipelines under construction but not yet completed*

Commenter **Cook Inlet Regional Citizens Advisory Council (RCAC)**

Cook Inlet RCAC supports the proposal to require leak detection systems for all new pipelines, including those not in areas classified as HCA. However, we believe that this requirement should also apply to the non-regulated onshore gathering lines discussed in our comments on "Extension of Reporting Requirements." As noted above, these types of pipelines contribute significantly to the number and volume of oil spills in Alaska, and the requirement for leak detection systems on these types of pipelines has the potential to reduce adverse environmental impacts from hazardous liquid pipeline spills. To reduce the compliance burden, PHMSA could consider requiring the addition of leak detection to currently exempt segments as they undergo repairs to some portion of the segment (e.g. 10% or more of the segment length) after the date the rules come into effect.	*Broaden applicability [Expand the requirement to all new pipelines, including onshore gathering and flow lines.]*

Commenter **Environmental Defense Center**

Even if a leak or rupture occurs in a pipeline, it is feasible to minimize the consequences of the leak with current technology. All hazardous liquid pipelines should be equipped with automatic leak detection and shutdown systems so that the pipelines will be shut down as soon as a leak occurs. Had the Plains All American Pipeline been equipped with such technology (as required and installed in all other oil pipelines in Santa Barbara County), the line would have shut down immediately, and more than 140,000 gallons of oil would not have spread 150 miles along the California coast. We believe, however, that this requirement should also apply to existing lines and that automatic shutdown systems should also be required. There is no need to defer making regulatory changes to address specific leak detection requirements, as recommended in the Notice. Sufficient information exists and has been analyzed for PHMSA to make specific recommendations now, in order to prevent unnecessary oil spills.	*Broaden applicability [Require automatic leak detection and shutdown systems to all lines, including exisiting lines]*
Commenter **Gas Processors Association**	
The study [Liquids Gathering Pipelines: A Comprehensive Analysis] generated several "key findings" that are related to PHMSA's proposal. The following quotes from within the body of the report directly illustrate why PHMSA's proposal is not appropriate for gathering lines at this time: 1) It should be emphasized that gathering lines present unique challenges to leak detection technologies. As a result, some care must be taken when extrapolating transmission line experience to gathering lines. 2) Gathering line systems are constantly transitioning in flow, pressure, and line-packing. Unlike transmission pipelines with very few branches, gathering systems have tens to hundreds of pipeline connections. These and other differences between transmission pipelines and gathering lines create greater challenges for designing, installing, and operating internal leak detection on gathering lines than transmission pipelines. 3)Company decisions regarding implementing new pipeline monitoring and leak detection technology rely upon, among other things, analysis of the cost and benefit. There is a need for objective data on the performance of different leak detection technologies under real-world conditions. 4) The better defined the operational conditions are, the more sensitive the leak detection method that can be applied. Low-pressure operation is common, and multiple flow inlets and very few outlets lead to significant flow variation as pumps cycle on and off or wells begin or cease production. The very nature of oil production leads to fluctuations that are not easily reduced or eliminated. 5) At this time, no technology has demonstrated undisputed reliability in detecting spills on interstate pipelines, much less on more problematic gathering lines.	*Exempt certain lines [Exempt gathering lines from requirement to install and maintain leak detection systems, due to technical challenges noted by commenter]*
The GPA urges PHMSA to provide relief for short sections less than one (1) mile in length and those that are located within facilities where they pose no risk to the public. [p.9]	*Exempt certain lines [Non-gathering line sections less than 1 mile in length and/or those located within facilities where they pose no risk to the public]*
Commenter **General Electric Oil & Gas**	
[Leak detection systems] should also be extended to gathering lines	*Broaden applicability [Expand to gathering lines]*
Commenter **Offshore Operators Committee**	

It is unclear in the proposed rule if this requirement will be applied to offshore gathering lines. The requirement to install certain types of leak detection on offshore gathering lines can be impractical on some offshore gathering lines due to current subsea well designs not having the technology available for basic leak detection (i.e. metering, temp, elevation data, etc.) or CPM, space limitations on platforms, intermittent nature of the operation and other factors.The OOC requests that PHMSA clarify their intent of this proposal and exclude this requirement for offshore gathering lines, or, at a minimum, allow offshore operators to choose the most appropriate form of leak detection based on risk and engineering judgment.

Exempt certain lines [Exempt offshore gathering lines or allow flexibility in choosing leak detection system]

Commenter **Pipeline Safety Coalition**

PSC strongly supports this proposal to require leak detection in all new hazardous liquid pipelines. PSC would encourage
the inclusion of:
1) all existing hazardous liquids lines and all lines under construction at rulemaking
2) prescriptive standards for leak detection classifications
3) prescriptive standards for acceptable leak detection procedures and devices
4) standards that are specific to location, community, and environmentally sensitive areas

Broaden applicability [Apply to all existing hazardous liquids lines and all lines under construction at rulemaking]

Commenter **Praxair**

PSI concurs with PHMSA's observation that there could be significant consequences from undiscovered leaks from certain long-distance gravity lines. It is also likely that the same could be the case for at least some rural gathering lines. Therefore PSA believes that leak detection requirements should probably be extended to such lines, and therefore supports gathering the data to substantiate the need for extending those requirements.

Broaden applicability [Include gravity and rural hazardous liquid gathering lines, if supported by data to be gathered]

In comments on the ANPRM, the National Association of Pipeline Safety Representatives raised concerns about ongoing small but undetected leaks that can produce a large total volume of leakage over time, and recommended addressing this problem. As indicated above, PSI shares this concern, and believes that PHMSA should specifically address this problem in its Hazardous Liquid Pipelines regulation.

Address ongoing, small, undetected leaks

Commenter **Tip of the Mitt Watershed Council**

In addition, this provision should be expanded beyond just newly constructed pipelines. Leak detection requirements should be applicable to existing pipelines when they undergo repair and replacement.

Broaden applicability [Require leak detection systems for existing pipelines when they undergo repair and replacement]

Subissue **Scope of requirements**

Commenter **Alliance for Great Lakes et al.**

In the NPRM, PHMSA states that computational pipeline monitoring ("CPM") systems comply with "section 4.2 of API RP 1130."47 However, a 2011 study on leak detection systems and regulations—commissioned by PHMSA—found that the preferred pipeline operator method for detecting pipeline issues involved CPM, Pressure/Flow monitoring, and supervisory control and data acquisition ("SCADA") systems.48 Because API 1130 "leaves it up to the operator to utilize the methodology that best suits them since each pipeline system is unique and has its own set of conditions," the study found that such systems "provide at best large rupture detection and all interviewed operators conceded this."49 Additional issues with CPM systems involved the need for significant "interpretation and analysis" of data, a lack of standardization of systems, and a lack of guidance on how to address the effectiveness of a given leak detection system on a given pipeline due to significant differences in pipeline design.50	*Add certain requirements [Require more rigorous leak detection for sensitive areas, valve spacing and location, and minimum rupture detection standards]*
In the NPRM, PHMSA states that computational pipeline monitoring ("CPM") systems comply with "section 4.2 of API RP 1130."47 However, a 2011 study on leak detection systems and regulations—commissioned by PHMSA—found that the preferred pipeline operator method for detecting pipeline issues involved CPM, Pressure/Flow monitoring, and supervisory control and data acquisition ("SCADA") systems.48 Because API 1130 "leaves it up to the operator to utilize the methodology that best suits them since each pipeline system is unique and has its own set of conditions," the study found that such systems "provide at best large rupture detection and all interviewed operators conceded this."49 Additional issues with CPM systems involved the need for significant "interpretation and analysis" of data, a lack of standardization of systems, and a lack of guidance on how to address the effectiveness of a given leak detection system on a given pipeline due to significant differences in pipeline design.50	*Add certain requirements [Require stricter performance standards, technology standards, and standardized operating procedures]*
Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**	
The Associations assume that this requirement, which is applicable to regulated onshore gathering lines, will not be applied to offshore gathering lines. API and AOPL request that PHMSA confirm this point in issuing a final rule. Applying this proposed requirement to offshore gathering lines would be an unwarranted change, as they are typically comprised of short segments and operate only intermittently. As such, applying leak detection to these lines would result in a potential increase of false alarms and would divert resources from higher-risk leak detection for onshore pipelines. [p.26]	*Exempt certain lines [Requirements should not apply to offshore gathering lines]*
Commenter **Assemblymember Das Williams, California State Assembly**	
As you know, on May 19, 2015, a pipeline owned by Houstonbased Plains All American Pipeline ruptured, spilling over 140,000 gallons of heavy crude oil along the Gaviota coast in Santa Barbara County, California. This spill damage could have been greatly reduced or prevented had rules been in place requiring best available technology for leak detection and shut off valves in environmentally sensitive areas.	*Set explicit performance requirements for LDS [Require best available technology for leak detection and shutoff valves in environmentally sensitive areas.]*
Commenter **Congresswoman Lois Capps**	
Clearer language is necessary in describing the minimum standard for leak detection systems and clarification of the incorporation of leak detection systems in pipelines under construction but not yet completed.	*Set explicit performance requirements for LDS [Include a minimum standard for leak detection systems]*
Commenter **Copper Country Alliance**	

In the first years after TAPS went into operation, aircraft with flew the pipeline to look for leaks and saboteurs. We understand that all sections of the pipeline were overflown out and back every day, and that each had an observer in addition to the pilot. We have heard that flights are less frequent now and that pilots serve as the observers. This was in addition to any surveillance done by ground crews. We were told by a former pilot that this system used to be tested by the placement of a piece of black plastic somewhere along the pipeline, and workers were told, "Now go find it." We urge that standards for surveillance and testing leak detection include procedures like these.	*Set explicit performance requirements for LDS [Require standards for surveillance and testing leak detection include air and ground observation]*
And it should have been required to keep workers at all pump stations for oil spill detection and quick response.	*Set explicit performance requirements for LDS [Require workers at all pump stations]*
Alyeska Pipeline Service Company should have been required to demonstrate that its electronic system was at least as effective as "boots on the ground" before reducing its work force.	*Set explicit performance requirements for LDS [Require documentation of that leak detection systems are functional]*

Commenter **County of Santa Barbara**

The County supports this proposal to require leak detection systems for all new hazardous liquid lines. This proposal should be clarified to identify how PHMSA would oversee operators' choice of particular leak detection system and ensure that the chosen system is adequate for each pipeline's unique characteristics.	*Clarify how PHMSA would oversee operators' choise of system and ensure the system is adequate*

Commenter **Earthworks**

PHMSA has indicated its intention to develop leak detection requirements at some future date, perhaps only applicable to ruptures. This approach would in effect be "too little too late" because spills and pollution persist for long periods of time before ever being detected.	*Set explicit performance requirements for LDS [Establish binding requirements for leak detection and repair protocols and associated timelines that all hazardous liquids pipeline operators must follow for both new and existing]*

Commenter **Energy Transfer Partners**

Although these two sections are in different Subparts, Subpart C-Design Requirements and Subpart F operation and Maintenance, respectively, they are at least in part duplicative. Perhaps some consolidation is in order, or a clarification that these two sections are not prescribing two different or independent leak detection systems.	*Clarify or consolidate the two leak detection Subparts*
PHMSA proposes that CPM leak detection systems, which are popular and widely used, must be designed in accordance with the requirements in section 4.2 of API RP 1130. That section, however, does not have requirements, per se. Rather, it provides a non-prioritized list of features that a CPM system may have and may be considered, also noting that no one methodology or application possesses all of the listed features and that some are more appropriate for specific pipeline systems. It also lists four categories of performance metrics to consider, but again with no requirements. Even the referenced Annex C provides factors and considerations, but not requirements. Therefore, if PHMSA intends to mandate specific requirements rather than provide a framework, which API RP 1130 does, then alternate rule language would be needed. ETP prefers the flexibility that API RP 1130 provides but seeks clarity from PHMSA regarding this intent so as to avoid a misconception that could result from the proposed language, which could be construed as more prescriptive than it actually is.	*Clarify whether the rule sets specific requirements or provides a flexible framework*

Commenter **Environmental Defense Center**

Even if a leak or rupture occurs in a pipeline, it is feasible to minimize the consequences
of the leak with current technology. All hazardous liquid pipelines should be equipped with automatic leak detection and shutdown systems so that the pipelines will be shut down as soon as a leak occurs. Had the Plains All American Pipeline been equipped with such technology (as required and installed in all other oil pipelines in Santa Barbara County), the line would have shut down immediately, and more than 140,000 gallons of oil would not have spread 150 miles along the California coast. We believe, however, that this requirement should also apply to existing lines and that automatic shutdown systems should also be required. There is no need to defer making regulatory changes to address specific leak detection requirements, as recommended in the Notice. Sufficient information exists and has been analyzed for PHMSA to make specific recommendations now, in order to prevent unnecessary oil spills.

Add certain requirements [Require automatic shutdown systems]

Commenter **Janet Alderton**

Highly trained operators are essential. The Enbridge pipeline disaster that occurred near Marshall Michigan in 2010 clearly demonstrates this. "Though alarms sounded in Enbridge's Edmonton headquarters at the time of the rupture, it was seventeen hours before a Michigan utilities employee reported oil spilling and the pipeline company
learned of the spill. Meanwhile, pipeline operators had thought the alarms were possibly caused by a bubble in the pipeline and, while for some time it was shut down, they also increased pressure for periods of hours to try to clear the possible blockage, spilling more oil."
Rigorous training standards and certification requirements for operators of the systems should be part of the new regulations.

Add certain requirements [Require standards and certification requirements for operators of systems]

Are existing SCADA systems considered to be "leak detection systems"?
There are no minimum rupture detection standards for leak detection systems.
Also, this proposal delays actually requiring leak detection systems to a later round of rule making. Requirements for the installation, spacing, and locations of shut-off valves in sensitive areas are also delayed.
More recent studies of leak detection systems than the 2012 Keifner and Associates study are available.

Clarify definition of "leak detection systems"

Commenter **Pipeline Safety Coalition**

PSC strongly supports this proposal to require leak detection in all new hazardous liquid pipelines. PSC would encourage
the inclusion of:
1) all existing hazardous liquids lines and all lines under construction at rulemaking
2) prescriptive standards for leak detection classifications
3) prescriptive standards for acceptable leak detection procedures and devices
4) standards that are specific to location, community, and environmentally sensitive areas

Set explicit performance requirements for LDS [Require prescriptive, site specific standards for leak detection classification, procedures, and devices]

Commenter **Pipeline Safety Trust**

in light of the apparent inability of current technology to identify leaks in any reasonable time frame, PHMSA should consider reviewing each operator's "worst case discharge" in its facility response plan in light of the actual limitations of the slowest systems (the worst case) being used. If that means a subterranean leak has to be big enough to have migrated to the surface of a distant water body for a pilot to see it during a right of way flyover, then that should be the size of the operator's worst case discharge in its facility response plan

Add certain requirements [The facility response plan should be based on the slowest leak detection system (the worst case) being used]

Commenter **Praxair**

PSI believes the proposal would be more useful to pipeline operators if the regulation were to provide more direction concerning required capabilities of leak detection systems that would meet the new regulatory requirements.	*Set explicit performance requirements for LDS*
Comments on the ANPRM3 included recommendations for third-party validation of leak detection standards. PHMSA has rejected those suggestions. PSI disagrees. Only those validated systems that are proven sensitive enough to detect leak small insidious leaks will provide public safety and benefit to Owner/Operators.	*Set explicit performance requirements for LDS [Require third-party validation of leak detection standards]*
A number of commenters on the ANPRM supported increased leak detection requirements for sensitive areas.6 However, PHMSA has taken the position that existing regulatory requirements are sufficient. Praxair agrees with NASPR and others that increased protection is appropriate.	*Agrees with PHMSA that additional requirements for sensitive areas are not required*
The Defense Logistics Agency commented in response to the ANPRM that any new regulatory standards should address false alarms. PSI concurs. Current technology can greatly reduce, if not eliminate false positives.	*Address false alarms*
In its discussion of ANPRM comments on new industry standards, PHMSA indicated that whether to require emerging technologies would be considered in evaluating what kinds of leak detection systems are appropriate for a particular pipeline, and that PHMSA will consider in its report to Congress whether the use of specific leak detection technologies should be required. PSI urges PHMSA to address this issue in the Hazardous Liquid Pipelines regulation.	*Clarify whether the use of specific leak detection technologies should be required*

Commenter **St Croix River Association (SCRA)**

The proposal [to expand the use of leak detection systems] is not accompanied by any required standard for the performance of leak detection systems. It also puts off addressing more stringent leak detection requirements for sensitive areas to a separate rule-making process, and puts off required valve installation (spacing and location) and minimum rupture detection standards to a separate rule-making.	*Add certain requirements [Establish minimum rupture detection standards]*
The proposal [to expand the use of leak detection systems] is not accompanied by any required standard for the performance of leak detection systems. It also puts off addressing more stringent leak detection requirements for sensitive areas to a separate rule-making process, and puts off required valve installation (spacing and location) and minimum rupture detection standards to a separate rule-making.	*Add certain requirements [Set more stringent leak detection requirements for sensitive areas]*

Issue ID **1.7** **Increased use of in-line inspection tools**

Subissue **Costs**

Commenter **American Gas Association (AGA)**

the NTSB recommendations do not consider if the recommendation is technically feasible, reasonable or practical and does not incorporate necessary resource allocations for implementing recommendations1. AGA agrees with API & AOPL's comments that there would be a significant burden associated with PHMSA's proposal to make all hazardous liquid pipelines in HCAs and areas that could affect HCAs capable of accommodating ILI tools within 20 years.	*Technical feasability issues with accomodating ILI tools within 20 years for hazardous liquid pipelines*

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

API and AOPL request that this proposal not be adopted, as imposing this requirement would require pipelines to incur exorbitant costs due to the age, design and location of the pipelines, without any demonstration of commensurate benefits. Such costs would dwarf the aggregate industry cost estimated by PHMSA in the preamble to the NPRM. The Associations have received industry estimates and cost figures that would follow from including this provision in a final rulemaking without providing sufficient exception for those pipelines that cannot be made ILI-capable, such as a number of gathering lines…

API and AOPL have received industry estimates suggesting the costs would run extraordinarily high even if the line itself did not need to be replaced. [p.27]

Costs are understated [Retrofits to allow ILI is too expensive]

Commenter **Gas Processors Association**

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

Costs are understated [The RIA insufficiently considers costs of assessments using ILI and the provision should be removed for gathering lines, while keeping the data collection component]

Commenter **Texas Pipeline Association**

Simply relying on age of a pipeline to determine its likelihood of replacement is inappropriate. The cost to replace existing pipelines merely to accommodate inline inspection tools could enormous. This proposed change needs more extensive review before moving forward. The issue may be resolved by allowing more time for replacement or retrofitting, but there is presently no sound foundation to support this proposed change.

No foundation in assessment of cost to support change

Subissue **Implementation schedule**

Commenter **Alliance for Great Lakes et al.**

the twenty year compliance timeframe should be reduced, as old pipelines built over fifty or sixty years ago should have such improvements made sooner as opposed to later. Twenty years is a significant amount of time, especially when considered in light of the exemptions PHMSA allows for pipelines constructed in a way that prevents ILI accommodation,
emergencies, and impracticability reasons . . . PHMSA should also develop a framework that assigns different compliance periods for pipelines based on factors such as age, prior leaks, corrosion, environmental circumstances that could affect the pipeline (i.e., subsidence, climate, seismicity), and other aspects such as those typically reviewed in integrity management studies. We suggest a similar approach for pipelines identified as being located in HCAs following the end of the initial compliance period. The current proposal requires ILI accommodation “within five years of the date of identification or before the performance of the baseline assessment, whichever is sooner.”

Allow different phase-in period that allow for risk factors [Develop framework with different compliance periods for pipelines based on various factors]

the twenty year compliance timeframe should be reduced, as old pipelines built over fifty or sixty years ago should have such improvements made sooner as opposed to later. Twenty years is a significant amount of time, especially when considered in light of the exemptions PHMSA allows for pipelines constructed in a way that prevents ILI accommodation,
emergencies, and impracticability reasons.

Shorten phase-in period [Reduce the overall compliance timeframe]

Commenter **Audubon Society of New Hampshire**	
We welcome the requirement that all pipelines potentially affecting an HCA must be able to accommodate inline (ILI) inspection devices, but consider 20 (twenty) years an excessive time period for fulfilling this requirement and have concerns about the multiple exemptions provided. We would prefer to see standards for ILI tools included in this rule, rather than deferred to a separate rulemaking process.	*Shorten phase-in period*
Commenter **Congresswoman Lois Capps**	
Greater clarity in the timelines for inline inspection requirements in high consequence areas is necessary. Allowing a 20 year timetable for adoption of these important safety regulations is much too long to bring about meaningful change and to keep our communities safe. This is not new technology, and PHMSA can and must push for these safety provisions to be adopted quickly. Instead, a shorter time frame (e.g., five years) could be established with an extension possible upon request with sufficient evidence for need and a provided plan of action to meet the standard.	*Shorten phase-in period [5 years]*
Commenter **County of Santa Barbara**	
ILI tools are a useful and proven technology for conducting pipeline integrity assessments in a non-destructive manner. The County suggests that the accommodation timeframe be reduced from 20 years to 5 years to ensure a higher degree of operational safety for pipelines within HCA's in a shorter timeframe. Exceptions could be allowed for pipelines with basic construction that would not accommodate the passage of an ILI tool.	*Shorten phase-in period [5 years]*
Commenter **Dakota Rural Action**	
Increasing the use of inline inspection tools such as smart pigs is essential for pipeline safety. Twenty years from now is too long, however. We are seeing an increase in pipelines and pipeline proposals in South Dakota which will affect our landowners now, and the companies operating these pipelines should be required to implement the use of inline inspection tools within the next five years.	*Shorten phase-in period [5 years]*
Commenter **Earthworks**	
PHMSA proposes to allow 20 years for what the agency calls a "gradual elimination of pipelines that are not capable of accomodating smart pig." Congress provided the basic authorization to PHMSA for an ILI rule more than a quarter century ago. Under these circumstances, PHMSA's concept of "gradual" smacks of gross understatement.	*Shorten phase-in period [5 years]*
Commenter **Environmental Defense Center**	
The proposed rule would require use of ILI tools within 20 years. As noted above, frequent and effective inspections are critical to preventing oil spills. ILI tools must be used as soon as possible; in no instance longer than within five years. The industry has been on notice since 1996 that pipeline operators should have systems that can accommodate such technology. (See Federal Register, Vol. 80, No. 197, page 61614, October 13, 2015.)	*Shorten phase-in period [no longer than within five years]*
Commenter **Kathy Hollander**	
Inline inspection tools should be required to be used much sooner than 20 years with all pipelines that could affect an HCA.	*Shorten phase-in period*
Commenter **National Transportation Safety Board**	

The solution offered by PHMSA was to change the time limit stated in paragraph (n)(3) from 20 years to 15 years. Although this change resolves the immediate issue, it does not address our concern that if an HCA is identified at any point up to the year 15, the pipeline upgrade to accommodate an internal inspection tool could be delayed until year 20. The NTSB believes that all newly identified HCA segments should be modified to accommodate an internal inspection tool on an augmented schedule, but not more than 5 years after the HCA is identified. We believe that 195.452(n)(3) should be revised to require newly identified areas be modified to accommodate internal inspection tools within 5 years of such an identification, but not to exceed the 20-year period specified in paragraph 195.452 (n)(2).	*Shorten phase-in period for new HCAs [5 year implementation for newly identified areas]*
Commenter **Pipeline Safety Coalition**	
PSC supports Proposal 6 however we do not agree with the proposed 20 year timeframe for compliance as it appears excessively unnecessary and counterproductive to improving a culture of safety. PSC supports a 5 year requirement.	*Shorten phase-in period [5 years]*
Commenter **Pipeline Safety Trust**	
We are disappointed that this proposal applies only to pipelines affectings HCAs and we see not detailed justification of the 20-year timeframe.	*Shorten phase-in period [5 year instead]*
Commenter **St Croix River Association (SCRA)**	
There is no rationale for a 20 year period before changes are completed in pipelines affecting HCAs, nor for a 5 year period for pipelines affecting newly identified HCAs, i.e., HCAs identified after the 20 year phase-in. The proposed rule also includes multiple exemptions such as where the pipe is constructed in such a way that an ILI device cannot be accommodated, e.g. for reasons of ‘impracticability’ and in an emergency. It puts off the development of standards for ILI tools, including the detection of stress corrosion cracking, to a separate rule-making.	*Shorten phase-in period [Recommend that the changes relating to accomodation of ILI devices be reduced significantly, perhaps to 5 years]*
However, there is no rationale for a 20 year period before changes are completed in pipelines affecting HCAs, nor for a 5 year period for pipelines affecting newly identified HCAs, i.e., HCAs identified after the 20 year phase-in. The proposed rule also includes multiple exemptions such as where the pipe is constructed in such a way that an ILI device cannot be accommodated, e.g. for reasons of ‘impracticability’ and in an emergency. It puts off the development of standards for ILI tools, including the detection of stress corrosion cracking, to a separate rule-making. ▯ We recommend that the changes relating to accommodation of ILI devices be reduced significantly, perhaps to 5 years. ▯ We recommend that all new pipelines constructed in HCAs be required to accommodate ILI devices immediately. ▯ We recommend an examination and tightening of the exemptions being proposed. ▯ We recommend the establishment of standards for ILI tools, including the detection of stress corrosion cracking.	*Shorten phase-in period [period for compliance (5 years)].*

However, there is no rationale for a 20 year period before changes are completed in pipelines affecting HCAs, nor for a 5 year period for pipelines affecting newly identified HCAs, i.e., HCAs identified after the 20 year phase-in. The proposed rule also includes multiple exemptions such as where the pipe is constructed in such a way that an ILI device cannot be accommodated, e.g. for reasons of 'impracticability' and in an emergency. It puts off the development of standards for ILI tools, including the detection of stress corrosion cracking, to a separate rule-making. � We recommend that the changes relating to accommodation of ILI devices be reduced significantly, perhaps to 5 years. � We recommend that all new pipelines constructed in HCAs be required to accommodate ILI devices immediately. � We recommend an examination and tightening of the exemptions being proposed. � We recommend the establishment of standards for ILI tools, including the detection of stress corrosion cracking.	*Shorten phase-in period [Lack of rationale for 20 years]*

Commenter **State of Washington Citizens Advisory Committee on Pipeline Safety**

The Committee supports efforts to require all pipelines that could affect high consequence areas to be capable of accommodating in-line inspection tools. However, a 20 year interval for accommodating ILI tools is far too long from a safety perspective and should be shortened to no more than 10 years.	*Shorten phase-in period [No longer than 10 years]*

Commenter **State of Washington Utilities and Transportation Commission**

Futher, the commission supports the National Transportation Safety Board recommendation that all newly-identified HCA segments should be modified to accommodate an internal inspection tool on an augmented schedule, but not more than five years after the HCA is identified.	*Shorten phase-in period [No longer than 5-year implementation for newly-identified HCA segments]*

Commenter **Tip of the Mitt Watershed Council**

We fully support the proposal to require all hazardous liquid pipelines in HCAs and areas that could affect an HCA be made capable of accommodating ILI tools. However, we recommend that the timeframe for adherence to this provision be shortened. Twenty years is far too long to wait to require the use of tools best suited to evaluate structural integrity of hazardous liquid pipelines.	*Shorten phase-in period*

Commenter **Western Organization of Resource Councils**

Although we think increasing the use of inline inspection tools such as smart pigs is a good idea, by giving companies 20 years to meet this standard, PHMSA is missing an opportunity to require the pipeline industry to modernize a vital piece of American infrastructure. The number of pipeline leaks and spills is on the rise nationwide and it is clear that we need to modernize and make our pipelines safer on a much more rapid schedule. We urge PHMSA to change the timeline required for companies to use inline inspection tools from 20 years to five years.	*Shorten phase-in period [5 years]*

Subissue **Reporting**

Commenter **Assemblymember Das Williams, California State Assembly**

As you know, on May 19, 2015, a pipeline owned by Houstonbased Plains All American Pipeline ruptured, spilling over 140,000 gallons of heavy crude oil along the Gaviota coast in Santa Barbara County, California . . . the operator should be required to submit its inline inspection data to PHMSA for review and verification.	*Require operators to submit inline inspection data to PHMSA for review and verification*

Commenter **National Transportation Safety Board**

Additionally, we note that the proposed regulations do not contain any progress reporting requirements during the 20-year completion period. Without a publicly transparent reportingrequirement, it will be difficult to ascertain compliance by the owners/operators. The NTSB is concerned that any requirement that establishes only a final deadline far in the future could encourage owners/operators to delay the effort to meet this requirement. The NTSB urges PHMSA to require owners/operators to develop comprehensive implementation plans with transparent progress reporting of intermediate milestones to ensure the modification of existing pipelines to accommodate the passage of ILI devices is completed within the 20-year time limit.

Require an implementation plan with progress reporting

Subissue **Scope of applicability**

Commenter **American Gas Association (AGA)**

PHMSA's proposal would require operators to assess non-High Consequence Areas (HCA)/ non-Integrity Management (IM) pipeline segments with an inline inspection (ILI) tool at least once every ten years. According to PHMSA the required assessments would "provide operators with valuable information they may not have collected if regulations were not in place." [Attachement 1] Id. At 61613

Requirements are duplicative/unecessary [Operators already performing ILI assessments on a majority of pipelines without it being required]

PHMSA's proposal would exempt from the ILI capable requirement those pipelines where basic construction would not accommodate the passage of an ILI tool. AGA encourages PHMSA to provide more details on what is meant by "basic construction".

Clarify definition of "basic construction"

Commenter **Audubon Society of New Hampshire**

We welcome the requirement that all pipelines potentially affecting an HCA must be able to accommodate inline (ILI)
inspection devices, but consider 20 (twenty) years an excessive time period for fulfilling this requirement and have concerns about the multiple exemptions provided. We would prefer to see standards for ILI tools included in this rule, rather than deferred to a separate rulemaking process.

Remove certain exemptions [Reduce the number of exemptions]

Commenter **Cook Inlet Regional Citizens Advisory Council (RCAC)**

We support the proposed change but recommend that PHMSA expand the requirement for inline inspection to include all hazardous liquid pipelines with design and construction specifications capable of allowing inline inspection, not just those in or adjacent to HCAs.

Broader applicability to piplines beyond HCAs [Apply to all hazardous liquid pipelines with design and construction that allow for inline inspection]

Commenter **Energy Transfer Partners**

The choice of ILI technology should be the operator's decision. It is understood that the operator needs to be able to justify such decisions. ETP also suggests that two concurrent rulemakings on the same subject can be confusing to responders and that PHMSA clarify how they will consider comments on this section provided to both this and the earlier rulemaking (Docket No. PHMSA-2013-0163).

Clarify interaction with earlier rulemaking

Commenter **Enterprise Products Partners**

PHMSA has proposed to increase the number of both HCA and non-HCA pipelines required to accommodate ILI tools. Part 195.120 (“Passage of internal inspection devices”) currently requires each new and replaced pipeline to be designed and constructed to accommodate the passage of an ILI device but allows operators to petition the Agency to approve the operator’s demonstration that compliance is impracticable due to construction-related time constraints and
problems. 49 C.F.R. Part 195.120(c). The Agency proposes in the NPRM to repeal this petition provision. NPRM at 61638-9. Further, the NPRM contains a proposed new Section 195.452(n), which would require existing pipelines that could affect HCAs to be modified to accommodate the passage of an ILI within twenty (20) years of the effective date of the Final Rule, unless the basic construction of the pipeline will not permit that accommodation or an emergency renders such accommodation impracticable. NPRM at 61642. The new Paragraph (n) would also require that pipelines in newly-identified HCAs after the 20-year period be made capable of accommodating ILIs within five years of the date of identification or before the performance of the baseline assessment, whichever is sooner.

Requirements are duplicative/unecessary

Commenter **Environmental Defense Center**

This requirement should either apply to all pipelines, or the definition of HCAs must be expanded to include, at a minimum, “waters of the U.S.”; state- and federally-listed threatened and endangered species critical habitat; local, state and federal protected areas; populated areas; major roadways; railroad crossings; and areas of local and state significance. To the extent areas are classified as either “It is” an HCA, or “It could be” a HCA, coastal areas should be classified as “It is” an HCA due to the presence of sensitive marine and coastal natural and cultural resources, recreation and tourism, and commercial fishing.

Broader applicability to piplines beyond HCAs [Apply to all pipelines or expand definition of HCAs]

Commenter **FlexSteel**

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

Composite pipe materials do no benefit from assessments conducted using ILI. The high density polyethylene (HDPE) material typically used as the liner material has very high insulating properties preventing the magnetic fields emitted by ILI from reaching any metallic reinforcing materials present.

Even if the magnetic fields were effective, the weight and brushes of an ILI would be detrimental to the smooth bore of the HDPE liner material. Some pipe compositions do not use metallic materials in the reinforcing layer making ILI ineffective as an assessment method.

Revise language requiring information for why ILI is not used based on the modifications proposed in section 1952.452(c)(1)(i)

Commenter **General Electric Oil & Gas**

PHMSA should require all hazardous liquid pipelines to accommodate ILI tools within 20 years

Broader applicability to piplines beyond HCAs [Require all hazardous liquid pipelines to accommodate ILI tools]

Commenter **National Transportation Safety Board**

Finally, it appears that the reference to 195.452(d)(3) contained in 195.452(n)(3) should be to the new section 195.452(d)(2), not (d)(3). The new language in the NPRM eliminates paragraph 195.452(d)(3). The NPRM proposed to change paragraph (d) to read: (d) When must operators complete baseline assessments? (1) All pipelines. An operator must complete the baseline assessment before the pipeline begins operation. (2) Newly-identified areas. If an operator obtains information (whether from the information analysis required under paragraph (g) of this section, Census Bureau maps, or any other source) demonstrating that the area around a pipeline segment has changed to meet the definition of a high consequence area (see § 195.450), that area must be incorporated into the operator's baseline assessment plan within one year from the date that the information is obtained. An operator must complete the baseline assessment of any pipeline segment that could affect a newly-identified high consequence area within five years	*Correct language error in 195.452(n)(3)*
Commenter **Pipeline Safety Trust**	
We are disappointed that this proposal applies only to pipelines affectings HCAs and we see not detailed justification of the 20-year timeframe.	*Broader applicability to piplines beyond HCAs*
Commenter **St Croix River Association (SCRA)**	
There is no rationale for a 20 year period before changes are completed in pipelines affecting HCAs, nor for a 5 year period for pipelines affecting newly identified HCAs, i.e., HCAs identified after the 20 year phase-in. The proposed rule also includes multiple exemptions such as where the pipe is constructed in such a way that an ILI device cannot be accommodated, e.g. for reasons of 'impracticability' and in an emergency. It puts off the development of standards for ILI tools, including the detection of stress corrosion cracking, to a separate rule-making.	*Broader applicability to piplines beyond HCAs [Recommend that all new pipelines constructed in HCAs be required to accomodate ILI devices immediately]*
There is no rationale for a 20 year period before changes are completed in pipelines affecting HCAs, nor for a 5 year period for pipelines affecting newly identified HCAs, i.e., HCAs identified after the 20 year phase-in. The proposed rule also includes multiple exemptions such as where the pipe is constructed in such a way that an ILI device cannot be accommodated, e.g. for reasons of 'impracticability' and in an emergency. It puts off the development of standards for ILI tools, including the detection of stress corrosion cracking, to a separate rule-making.	*Set more stringent requirements [Examine and tighten the exemptions being proposed]*
Commenter **State of Washington Utilities and Transportation Commission**	
As operators have been aware of these standards for more than 25 years, the commission suggests that the provision apply to all hazardous liquid pipelines.	*Broader applicability to piplines beyond HCAs [Require all hazardous liquid pipelines to accommodate ILI tools]*
Commenter **Tip of the Mitt Watershed Council**	
Additionally, alternative assessment methods, such as direct assessment, have been deemed ineffective by the National Transportation Study Board because they fail to evaluate the integrity of an entire pipeline and can only identified potential threats associated with corrosion. As a result, direct assessments identify significantly less anomalies than an ILI tool. Given the benefits of ILI, all hazardous pipelines should be made capable of accommodating ILI tools.	*Broader applicability to piplines beyond HCAs [Require ILI tools for all hazardous pipelines]*
In addition, we recommend that this provision be expanded to include all hazardous liquid pipelines, not just those affecting HCAs. It is readily acknowledged that ILI tools are able to identify threats that cannot always be identified using other assessment methods.	*Broader applicability to piplines beyond HCAs [Expand providion to all hazardous liquid pipelines]*

the basic construction exception allowing pipelines to be constructed without being able to accommodate ILI because of terrain or location should be repealed. If the location or terrain does not allow for ILI tools, the operator will ultimately be unable to effectively evaluate the structural integrity of the pipeline. If an operator will be unable to ensure safety pipeline operation and maintenance, the pipeline should not be sited in such a location or terrain.

Remove certain exemptions [Remove exception for basic construction because of terrain or location]

Subissue **Scope of requirements**

Commenter **American Gas Association (AGA)**

As discussed in the previous section, AGA adamantly disagrees with PHMSA's consideration of ILI as superior to other approved assessment methodologies in all situations. PHMSA has provided no support for its claim that "ILI tools also provide superior information about incipient flaws." [p.3]

Allow flexibility in assessment methods [PHMSA has not provided support for use of ILI tools]

AGA believes a more meaningful method for expanding integrity management principles is to allow operators to conduct a full system risk analysis and then determine whether to perform additional P&M measures or an assessment using one of the four approved assessment methods. Such a method would recognize engineering judgment in the choice of which P&M measure to deploy or which assessment method to utilize. AGA encourages PHMSA to review existing and ongoing studies that evaluate the effectiveness of P&M measures and assessment methodologies that highlight alternatives to ILI where they may be more beneficial for pipeline risk management. [p.2]

Allow flexibility in assessment methods [Evaluate the effectiveness of P&M measures and assessment methodologies that highlight alternative to ILI]

AGA encourages PHMSA to recognize that technologies are constantly developed and improved. By isolating the regulatory requirement to ILI, PHMSA is neglecting the possibility of future inspection assessment methods.

Allow flexibility in assessment methods [Regulatory requirement of ILI in IM process prevents future inspection assessment methods and ignores applications where other measures might be better suited]

PHMSA has provided no support for its claim that "ILI tools also provide superior information about incipient flaws." 80 Fed. Reg. 61615. Each of the approved assessment methods for hazardous liquid pipelines as well as natural gas transmission pipeline have been utilized by operators for integrity management and each methods has its benefits and limitations in addressing specific threats.

Allow flexibility in assessment methods [Other assessment methods are utilized by operators for IM]

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

… tremendous volume of petitions under Section 190.9 requesting a finding that the physical attributes or operational limitations of the pipeline do not allow for the passage of an ILI device. PHMSA has not demonstrated how this process would improve public safety given that pipelines will need to petition for such relief due to the physical limitations of these lines. The Associations support increased use of ILI in new lines and recognize its value in promoting an understanding of pipeline integrity. However, rather than creating an onerous administrative burden on operators and PHMSA to request the use of hydrostatic testing and other detection approaches through a formal petition, API and AOPL request that PHMSA remove the requirement to petition under Section 190.9 and instead continue to allow operators to exercise their expertise and engineering judgment in using the most effective and efficient methods of evaluating the integrity of their facilities with prior notification to the Office of Pipeline Safety. [p.27]

Allow flexibility in assessment methods [Operators should be able to exercise expertise and judgement in using the method to evaluate integrity]

Commenter **Audubon Society of New Hampshire**

We welcome the requirement that all pipelines potentially affecting an HCA must be able to accommodate inline (ILI) inspection devices, but consider 20 (twenty) years an excessive time period for fulfilling this requirement and have concerns about the multiple exemptions provided. We would prefer to see standards for ILI tools included in this rule, rather than deferred to a separate rulemaking process.	*Establish performance standards [Include standards for ILI tools]*
Commenter **Environmental Defense Center**	
We agree that pipelines that are not capable of accommodating smart pigs should be replaced with new pipelines that can utilize this important inspection tool. The rule should also require other inspection tools and methods, such as hydrostatic pressure testing, where certain types of anomalies are detected. These other technologies can provide additional information regarding the condition and vulnerabilities of a pipeline system.	*Establish performance standards [Require other inspection tools and methods when certain types of anomalies are detected to provide additional information]*
Commenter **Independent Petroleum Association of America**	
The Proposed Rules do not refer to a technical study suggesting that the only accurate means of monitoring pipeline status is through the use of ILIs, as one has not been completed. Before mandating technology for the pipeline industry, PHMSA should conduct a study and determine if requiring ILI is truly the appropriate path to take to monitor pipeline corrosion given the current state of technology along with a detailed analysis of the economic impact of this requirement. The Proposed Rules should be revised to require pipelines to be capable of monitoring for particular data regarding pipeline integrity while leaving it to pipeline operators how they achieve compliance.	*Allow flexibility in assessment methods [PHMSA should conduct a study to determine if ILI is the appropriate path for monitoring pipeline corrosion]*
The Proposed Rules do not refer to a technical study suggesting that the only accurate means of monitoring pipeline status is through the use of ILIs, as one has not been completed. Before mandating technology for the pipeline industry, PHMSA should conduct a study and determine if requiring ILI is truly the appropriate path to take to monitor pipeline corrosion given the current state of technology along with a detailed analysis of the economic impact of this requirement. The Proposed Rules should be revised to require pipelines to be capable of monitoring for particular data regarding pipeline integrity while leaving it to pipeline operators how they achieve compliance.	*Establish performance standards [Pipeline operators should be required to monitor for particular data rather than prescibing the exact methods for how they achieve compliance]*
Commenter **Pipeline Safety Coalition**	
PSC additionally supports more standardized, prescriptive safety standards for the ability of consistency to increase safety through both operator and community continuity and understanding.	*Establish performance standards [Require standardized, prescriptive safety standards]*
Commenter **Pipeline Safety Trust**	
We are also disappointed that the proposal delays the development of standards for ILI tools, including the detection of stress corrosion cracking, to a sperate rulemaking.	*Establish performance standards*
We note that the newly proposed section 195.416 will subject all HL pipelines to periodic inspections, yet approximately 13% of these piopelines cannot accommodate ILI devices. [suggested language]	*Code language recommended to modify existing pipes to become piggable if possible within 20 year timeframe*
We also recommend expressly specifying that Close Integral Survey results be integrated into ILI device findings	*Recommends requirement to integrate CIS into ILI device findings*
Commenter **St Croix River Association (SCRA)**	
Specification that operators consider the accuracy (tolerance) of ILI tools when evaluating inspection tools.	*Establish performance standards [Consideration of the accuracy (tolerance) of ILI tools when evaluating inspection tools]*

There is no rationale for a 20 year period before changes are completed in pipelines affecting HCAs, nor for a 5 year period for pipelines affecting newly identified HCAs, i.e., HCAs identified after the 20 year phase-in. The proposed rule also includes multiple exemptions such as where the pipe is constructed in such a way that an ILI device cannot be accommodated, e.g. for reasons of 'impracticability' and in an emergency. It puts off the development of standards for ILI tools, including the detection of stress corrosion cracking, to a separate rule-making.

Establish performance standards [Recommend the establishment of standards for ILI tools, including the detection of stress corrosion cracking]

Commenter **Tip of the Mitt Watershed Council**

Additionally, there is no system to verify compliance with the regulation. PHMSA should develop associated reporting requirements to ensure that operators modify pipelines to be capable of accommodating ILI appropriately and within the required timeframe.

Include reporting requirements

Issue ID **1.8a** **Other: Data integration**

Subissue **Implementation period**

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

API and AOPL urge PHMSA to delay the implementation of this requirement for five years to allow operators to establish the programs required to implement the attributes in a spatial platform, which will include implementing the new information systems, populating data into these systems, and validating of the quality of the data process. The Associations believe a five-year period is appropriate, as this timeframe is consistent with the language currently contained in Section 195.452(j).[p.28]

Provide phase-in period [Allow 5 years to implement data integration requirements]

Subissue **Scope of applicability**

Commenter **American Gas Association (AGA)**

AGA also suggests that PHMSA focus on the "analysis" of information and attributes rather than the "integration" of information and attributes. While the requirement to integrate data may be suitable for large hazardous liquid pipeline operators or interstate gas pipeline operators, the requirement would not be appropriate for small operators, which have far fewer miles of pipelines and thus resources. Imposing such a requirement on these smaller operators would place unnecessary, unprecedented, and very burdensome data integration requirements on these small operators. AGA suggests the language for proposed §195.452(g)(1) could be revised to "Analyze appropriate available information and attributes about the pipeline." AGA believes that where appropriate, the obligation to "analyze" would include the obligation to "integrate," and that this language would capture PHMSA's stated concerns regarding integration and would further pipeline operator's requirements for data analysis.

Focus on integration instead of analysis results in a burden for small operators and new suggested language should use the term "analyze"

Commenter **Gas Processors Association**

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

Disagree with the definition of Significant Stress Corrosion Cracking

Subissue **Scope of requirements**

Commenter **American Gas Association (AGA)**

AGA has significant concerns on PHMSA's proposal to establish the pipeline attributes that must be included in information analyses and the requirement to integrate analyzed information for hazardous liquid pipelines. Id. 61615. AGA believes operators should independently develop their list of information and attributes to be included in data analysis and integration instead of PHMSA providing a suggested list.

Operators should independently determine the information and attributes to be included in data analysis and integration

AGA is also concerned with PHMSA's proposed requirements to identify spatial relationships among anomalous information:
Identify spatial relationships among anomalous information (e.g. corrosion coincident with foreign line crossings; evidence of pipeline damage where aerial photography shows evidence of encroachment). Storing the information in geographic information system (GIS), alone is not sufficient. An operator must analyze for interrelationships among the data. 80 Fed. Reg. at 61641 (proposed §195.452(b)(4) (emphasis added).
AGA reminds PHMSA that there is no current regulatory requirement for an operator of hazardous liquid or natural gas pipelines to maintain or utilize a geographic information system (GIS), even though this proposed code language suggests that there is such a requirement.

GIS is referred to in a manner that suggests there is a requirement to utilize a GIS and should be removed

Commenter **Montana Department of Environmental Quality**

DEQ suggests that PHMSA provide this GIS information attributes to States where this occurs. This would allow for the potentially affected State to have these GIS attributes and to have an understanding of the locations where operators have taken further steps for inspecting their pipelines.

Provide GIS information to states

Issue ID **1.8b** **Other: Baseline assessment of newly-constructed pipelines**

Subissue **Scope of requirements**

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

The Associations request that PHMSA clarify that hydrostatic testing is an acceptable method of meeting this requirement for new construction. [p.28]

Clarify compliance approaches

Commenter **Energy Transfer Partners**

In subsection (d), PHMSA proposes that "An operator must complete the baseline assessment before the pipeline begins operation." In response to a webinar question on this subject, PHMSA stated this did not mean an ILI assessment had to be completed, but that a commissioning pressure test could be taken as the baseline assessment prior to operation, with ILI to follow per the schedule, the implementation of which is unspecified at this time. Does this answer mean that PHMSA believes ILI prior to beginning operation is impracticable, the only allowed reason for not using ILI? If so, this section, §195.452(d)(1), should be clarified to state this.

Clarify use of ILI prior to operation

Issue ID **1.9** **Other issues (out of scope)**

Subissue **Dil-bit, tar sands**

Commenter **Kathy Hollander**

Most importantly, pipelines carrying tar sands oil must be treated differently than other hazardous pipelines. The toxic mix of volatile chemicals used as diluent is hazardous in its own right and bitumen spilled in water bodies is impossible to ever completely clean up. Tar sands crude oils must require stricter standards, as the recent NAS study clearly indicates.

Regulate pipelines carrying tar sands oil differently

Commenter **Pipeline Safety Trust**

Reporting requirements to submit more information to PHMSA and local governments about what's in the pipes: NAS study recommendations concerning dilbit - consistent with NTSB recommendation for system specific information

NAS study recommendations concerning dilbit

Commenter **Sharon Natzel**

Please take into account and act upon the suggestions identified in the study by the National Academies of Sciences, Engineering, and Medicine recently released in 2015 entitled "Spills of Diluted Bitumen from Pipelines, a Comparative Study of Environmental Fate, Effects and Response. According to the study's news release, the way diluted bitumen changes after weathering calls for greater concern compared with commonly transported crude oils and special response strategies and tactics. It also states: a more comprehensive and focused approach is needed to improve preparedness for spills of diluted bitumen and to spur more effective cleanup and mitigation measures when spills do occur.

Address diluted bitumen

Commenter **Tip of the Mitt Watershed Council**

Furthermore, rules need to be developed with respect to diluted bitumen. While the National Academy of Sciences 2013 report, "Effects of Diluted Bitumen on Crude Oil Transmission Pipelines," concluded that transportation of diluted bitumen by pipeline was not more likely to cause releases, the follow-on study, "Spills of Diluted Bitumen from Pipelines: A Comparative Study of Environmental Fate, Effects, and Response," concluded that that bitumen, if spilled, has unique properties that affect its behavior in the environment, and that these differences warrant modifications to the regulations governing diluted bitumen spill-response plans, preparedness, and cleanup. Michigan, unfortunately, had first-hand experience with the difficulties associated with the containment and cleanup of diluted bitumen released into the aquatic environment. As a result, we believe it is imperative that PHMSA develop rules specific to diluted bitumen.

Regulate bitumen

Subissue **Flow Control Technology**

Commenter **Alliance for Great Lakes et al.**

By 1994, Congress required the Office of Pipeline Safety to "survey and assess the effectiveness of emergency flow restricting devices,"25 and within two years, "prescribe standards on the circumstances under which an operator of a hazardous liquid pipeline facility must use an emergency flow restricting device."26 Such an analysis was never issued. PHMSA currently allows pipeline operators to determine if an EFRD is needed through their own operator pipeline
risk analysis, even if the pipeline segment is located in a HCA.27 PHMSA should mandate the installation of EFRDs on all pipelines and should prescribe the circumstances and locations that warrant EFRDs. At the very least, such a mandate should apply to pipelines located in HCAs and USAs. In addition, EFRD technology should be installed on all pipelines that traverse HCA areas generally, as opposed to simply when an operator determines through their own risk assessment
that an EFRD is necessary.30 PHMSA should not defer requiring this while it studies the issue.31
PHMSA should address the application of EFRD in HCAs by amending the current rule now.

Require the use of EFRD use in certain circumstances

Commenter **County of Santa Barbara**

The existing pipeline regulations under 49 CFR Part 195 do not currently require the
use of EFRDs. The County proposes that best available technology, such as automatic shut down
systems be required for hazardous liquids pipelines. Automatic shutoff systems are triggered by pre-set
parameters and do not require human action, decision-making, or intervention to shut down the
pipeline system. Incorporation of automatic shut down systems would minimize the potential impacts
from oil spills. Pipeline operators in Santa Barbara County routinely include state of the art leak
detection and spill prevention technology, including automatic shutoff systems, in their pipeline project
proposals. Automatic shutdown technology is feasible and warranted; all of the major pipelines in
Santa Barbara County are equipped with automatic shutoff systems, with the notable exception of the
Plains All American Pipeline system, which ruptured and caused the May 2015 Refugio oil spill. If
the Plains All Arnerican Pipeline system had been equipped with an automatic shutdown system, the
substantial environmental damage caused by the May 2015 Plains All American Pipeline spill could
have been miniinized. We suggest supplementing the regulations to require that hazardous liquids
pipelines be equipped with a system to automatically shut down the source of oil (i.e. the shipping
pump) upon 15% deviation from normal operating parameters including high and low pressure and
high and low flow. Additionally, the system should include an alarm that notifies the operator at 10%
deviation so that necessary actions are proactively taken to prevent a potential pipeline rupture or leak.

Require use of BAT and a system to automatically shut down the source of oil upond 15% deviation from normal operating parameters

Subissue **HCA definition**

Commenter **Alaska Wilderness League et al.**

In its proposed rule, PHMSA includes additional requirements for hazardous liquid transmission pipeline segments that are not covered under the current Integrity Management rules. These less strict integrity management requirements in the NPRM do not, however, obviate the need to protect High Consequence Areas (HCAs) that were neglected in the original HCA rule. At the time of HCA rule development, it was anticipated that the federal government would expand the areas covered over time.

Expand HCAs to include transportation infrastructure (e.g., road and rail crossings), public lands, waterways and wetlands covered by the Clean Water Act, and cultural, historic, archeological, recreational, and subsistence areas

Commenter **Alliance for Great Lakes et al.**

The scope of High Consequence Areas ("HCAs") should be broadened to cover more
environmentally-sensitive areas. Congress directed the Department of Transportation ("DOT"),
which oversees PHMSA, to consider areas where damage caused by a pipeline spill would
"likely cause permanent damage or long-term environmental damage" in 1996.4 However, the Presidential memorandum which accompanied the amendment directed DOT to also consider the potential for short-term damage from spills5 and noted that Unusually Sensitive Areas ("USAs") should not be limited to those explicitly stated in the act's text.6 In addition, the Environmental Protection Agency and Department of Justice "strongly urged" DOT to classify more areas as HCAs. A. PHMSA should lower the threshold level for "high population" and clarify "other
populated area." B. PHMSA should expand High Consequence Areas by revising the definition of
Unusually Sensitive Areas. 1. PHMSA should expand USAs to better protect endangered and threatened
species. 2. PHMSA should afford greater protection to water supply systems as USAs. C. Increased Public Input into the HCA Process

The scope of HCAs should be broadened

Commenter **Audubon Society of New Hampshire**

We appreciate the requirement for verification of HCA designations on at least an annual basis. In addition, we would like to see an expanded definition of HCAs, including but not limited to railroad crossings, major transportation corridors, all populated areas, "Waters of the United States" as defined in the Clean Water Act, and state and federal lands. We would also like to see a formally recognized opportunity for states, municipalities, and the public to participate in the designation of HCAs.

Expand definition of HCAs

Commenter **Commonwealth of Virginia Deparment of Conservation and Recreation (on behalf of Virginia Cave Board)**

The Virginia Cave Board encourages the PHMSA to consider revising the definition of High
Consequence Areas {HCA) to include hazardous liquid pipelines located on cave and karst terrain

Define HCA to include caves and karsts

Commenter **Congresswoman Lois Capps**

Furthermore, gaps remain within the established definition for "high consequence areas." Existing definitions of HCAs, as written, do not automatically include coastal and riparian areas. Given the sensitivity of coastal and riparian systems, these areas should be actively protected as they act as transition zones between land and water. Furthermore, there should be codification of a means for public input on the identification of potential HCAs.

Expand definition of HCAs

Commenter **County of Santa Barbara**

HCAs are narrowly defined in current regulations. The County suggests that the regulations include an expanded definition of HCAs to include navigable waterways, State- and federally-listed threatened and endangered species critical habitat, and areas of local significance. Additionally, the County suggests that the regulations allow for the involvement of local government entities when making HCA determinations so that they may participate in the process of identifying areas of local significance.	*Expand the definition of HCAs*
Commenter **Dakota Rural Action**	
It is critical that the final rule expand the definition of High Consequence Areas. In order to protect clean water public lands, population centers, and transportation routes from pipeline disasters, the definition should include roadways, railroad crossings, "Waters of the United States" as defined by the Clean Water Act, state and federal wildlife refuges, national parks, national monuments, national recreation areas, national forests, and population centers (as defined for Class 2 locations under 49 CFR 192.5). We hope that expanding the protections under the HCA definition that places like the Yellowstone River in Montana will be further protected from potential pipeline spills.	*Expand definition of HCAs*
Commenter **Earthworks**	
Earthworks believes that expanding the number of HCA-eligible places will best protect communities and the environment from the ris that pipelines everywhere pose to people, land, water, wildlife, and air.	*Expand HCAs definition*
Commenter **General Electric Oil & Gas**	
PHMSA should require all operators to identify "spill consequence areas" based on the topography of the pipeline ROW, and identify the existence of water tables that could become contaminated by a spill. CPS and computerized survey maps are available to produce these consequence prediction models. Because of the environmental risk, and potential for drinking water contamination, any such identified areas should be treated similar to HCAs	*Require identification of "spill consequence areas" based on topography*
Commenter **Janet Alderton**	
The definition of High Consequence Area should include all areas where pipelines traverse wetlands and fresh or marine water bodies such as streams, rivers, and off-shore pipelines.	*Expand definition of HCAs*
Commenter **Joletta Bird Bear**	
the High Consequences designated areas must be applied to water intakes that are at high risk to pipeline leaks, spills, explosions and the federal emergency response must notify the impacted community of the ensuing public safety risks	*Expand definition of HCAs*
Commenter **Judy Skog**	
In your definition of High Consequence Areas, I would urge you to include all populated areas (same as defined for Class 2 locations under 49 CFR 192.5); major roadways; railroad crossings; "Waters of the United States" as defined in the Clean Water Act; state and federal wildlife refuges; national parks, monuments and recreation areas; national forests; and more involvement of the public, state, and local governments.	*Expand definition of HCAs*

Commenter **Kathy Hollander**

The definition of High Consequence Areas needs to be expanded to include major roadways; railroad crossings; "Waters of the United States" as defined in the Clean Water Act; all populated areas (same as defined for Class 3 locations under 49CFR 192.5); state and federal wildlife refuges; national parks, monuments, and recreation areas; national forests; and more involvement of the public, state and local governments.

Expand definition of HCAs

Commenter **Montana Department of Environmental Quality**

Additionally, Montana DEQ supports more in depth consideration of what a high consequence area is by including any water bodies that support a drinking water supply.
Further, Montana is the headwater state for several rivers that, if impacted by spills,
may, in turn, affect waters in other states. Therefore, additional protections should be
considered for headwaters.

Expand definition of HCAs

Commenter **Pipeline Safety Coalition**

Overall, PSC has concerns over the lack of reassessment of HCAs. We reported to the PA PITF the need to redefine
HCA's and to assess "when is too much too much; when is too close too close?" in this age of expanding infrastructure.
When new hazardous liquids pipeline projects assume to expand in residential areas and contain up to four (4) lines (up to 24") and within 20 feet of the foundations of 300 homes in a planned one community in a string of similar planned
communities, we need to reassess how that HCA is classed and how those pipelines are required to be maintained and
inspected and the safety of constructing such infrastructure in a known HCA.

Reasses definition of HCA's

Commenter **Pipeline Safety Trust**

There are three aspects of a review of hazardous liquid pipeline safety regulations that we feel should have been included in this rule, but are not: leak detection and valves; safety regulations for non-regulated gathering lines and gravity fed lines; and scope of high consequence areas, or more broadly, a review of what benefits integrity management programs bring to high consequence areas.

Rule should address the scope of HCAs

Commenter **Sharon Natzel**

The expansion of the definition of high consequence areas to include: groundwater and aquifers which provide water and are interrelated with surface water and drinking water sources for rural homes and towns and cities. This is especially important in northern MN where the groundwater is susceptible to contamination because of the glacial materials deposits there.
The expansion of the definition of high consequence areas to include: the pristine northern lakes area of Minnesota where there is a minimum of pollution as compared to other areas of Minnesota.

Expand definition of HCAs

Commenter **St Croix River Association (SCRA)**

Expansion of the definition of High Consequence Areas to Include: major roadways; railroad crossings; “Waters of the United States” as defined in the Clean Water Act; all populated areas (same as defined for Class 2 locations under 49 CFR 192.5); state and federal wildlife refuges; national parks, monuments, and recreation areas; national forests; more involvement of the public, state, and local governments. PHMSA states that changes are not needed in the definition of HCAs because of their measures to adopt additional safety standards for pipelines located outside of HCAs. The measures proposed, however, are not integrity management measures that require careful risk analysis and detailed planning for pipeline safety; they are only measures to require inline inspection that is a small fraction of what is currently required within HCAs. These measures do not substitute for the need to carefully look at HCA boundaries, definition, and process.	*Definition of HCA to include additional factors*
Expansion of the definition of High Consequence Areas to Include: major roadways; railroad crossings; “Waters of the United States” as defined in the Clean Water Act; all populated areas (same as defined for Class 2 locations under 49 CFR 192.5); state and federal wildlife refuges; national parks, monuments, and recreation areas; national forests; more involvement of the public, state, and local governments. PHMSA states that changes are not needed in the definition of HCAs because of their measures to adopt additional safety standards for pipelines located outside of HCAs. The measures proposed, however, are not integrity management measures that require careful risk analysis and detailed planning for pipeline safety; they are only measures to require inline inspection that is a small fraction of what is currently required within HCAs. These measures do not substitute for the need to carefully look at HCA boundaries, definition, and process.	*expansion of the HCA definition*
Commenter **Theodora Bird Bear**	
1) The definition of "High Consequence" areas must include tribal Indian reservation, especially in an oil & gas development like the Bakken in western North Dakota. 2) "High Consequence" areas must be expanded to include water bodies, like the Missouri River/Lake Sakakawea in western North Dakota, which are the primary sources of public drinking water. 3) "High Consequence" areas must include water intake systems such as the Missouri River's Bear Den Bay water intake system for the Mandaree community on the Fort Berthold Indian Reservation in North Dakota.	*Expand HCA to include tribal reservation land*
Commenter **Tip of the Mitt Watershed Council**	
As well, modifications to or the expansion of High Consequence Area is omitted from this notice of proposed rulemaking. Proposing additional safety standards for pipelines located outside of areas that could affect an HCA should not be considered a substitute for taking action on HCA boundaries, definition, and process. While the proposed rule requires inspections on pipelines located outside of HCAs, the proposed rule change does not require careful risk analysis and detailed planning for pipeline safety that IM provides.	*Expand HCAs definition*
Commenter **Western Organization of Resource Councils**	

With regard to High Consequence areas we believe it is critical that the final rule expand the definition of High Consequence Areas. In order to protect clean water public lands, population centers, and transportation routes from pipeline disasters, the definition should include roadways, railroad crossings, “Waters of the United States” as defined by the Clean Water Act, state and federal wildlife refuges, national parks, national monuments, national recreation areas, national forests, and population centers, as well as rural farmsteads, stock and domestic water wells and reservoirs, and aquifers and aquifer recharge areas. ,We hope that expanding the protections under the HCA definition that places like the Yellowstone River in Montana will be further protected from potential pipeline spills.	*Expand HCAs definition*

Subissue **hydrotest requirements**

Commenter **Pipeline Safety Trust**

Strengthen hydrotest requirements - including heightening both pressure and duration. (Keystone XL condition 22)	*pressure and duration requirements for hydrotests*

Subissue **IM analysis**

Commenter **Alliance for Great Lakes et al.**

The Integrity Management (“IM”) program currently applies to pipelines located in High Consequence Areas (“HCAs”) and areas that could affect HCAs. The program should be expanded to protect all hazardous liquid pipelines. HCAs are arbitrarily based on population size, meaning not all residential areas located near pipelines are receiving adequate protection. Expanding the IM program would allow for better protection of public health and the environment by requiring line assessment, leak detection systems, and specific repair schedules. However, HCAs should remain the highest priority of the program.	*Expand IM program*

Commenter **St Croix River Association (SCRA)**

Expansion of the list of information and attributes to be considered in the IM analysis including including the need to identify interrelationships affecting risk among the different data collected.	*Expansion of the information and attributes considered in the IM analysis*

Subissue **Leak detection system standards**

Commenter **Accufacts**

Concerning leak detection rulemaking efforts, I advise that such regulatory efforts first focus on rapid identification of rupture (big opening) releases, then consider if leak detection (much smaller opening) is capable for a specific system. Given the number of liquid pipeline ruptures that have released for many hours before a pipeline shutdown and isolation was initiated, even remote rupture detection is complicated. In remote release detection systems, rupture detection will be also be driven by the elevation profile and will also incorporate additional information such as hydraulic profiles to aid release detection designers. Leak detection systems intended to capture smaller rate releases are much more complicated and difficult than rupture detection systems, and while liquidleaks in the wrong location can be very dangerous and cause serious environmental damaging, providing leak detection regulation that will actually work is extremely complicated and challenging.	*Suggest leak detection be considered in a future regulatory process*

Commenter **Alaska Wilderness League et al.**

Among its hazardous liquid transmission pipeline integrity management rules, PHMSA requires that operators have a means to detect leaks, but there are no performance standards for such systems. This is in contrast to the States of Alaska and Washington which both have leak detection performance standards. Alaska, for example requires that all crude oil transmission pipelines have a leak detection system capable of promptly detecting a leak of no more than 1% of daily throughput.

Since all pipeline operators measure throughput, it is unlikely that proposed section 195.444, Leak Detection, which does not contain leak detection performance standards, will result in any changes in pipeline operations. As a result, this proposed section does not provide any additional protections for important environmental assets such as rivers and lakes.

Establish leak detection system standards

Commenter **Dakota Rural Action**

We urge PHMSA to prescribe performance standards for required leak detection systems, including what type of systems must be used in sensitive areas, and clearly defined minimum rupture detection standards.

Include standards fo leak detection systems

Commenter **Earthworks**

The proposed rule would require all hazardous liquids pipelines to be subject to a system for detecting leaks. However, PHMSA has neglected to define "system" or develop associated performance standards--yet again leaving it up to operators to decide whether and how to take action.

Require definition of leak detection system

Commenter **Greg Lehmann**

PHMSA is proposing that all new hazardous liquids pipelines be designed to include leak
detection systems (LDS). While I fully concur with the proposal, I feel that the lack of any prerequisite
specifications or standards of LDS performance falls short to ensure the success of the proposal. New
requirements for leak detection on non-HCA segments without the specification of more rigorous (or
delineated) requirements for more sensitive areas may not be adequate. I also feel that the
requirement of a leak detection system without direction on methods for mitigation upon detection
(i.e., isolation valving, pipeline wide shutdown) is inadequate. [includes SCADA related pipeline standard]

Require standards for leak detection systems

Commenter **Janet Alderton**

All leak real time leak detection systems require maintenance to sustain performance levels. The proposed regulations do not have performance standards linked to different types of detection systems.

Require performance standards for detection systems

Commenter **Kathy Hollander**

The mention of leak detection systems without a specification of the type of requirement for such a system is unacceptable.

Include standards for leak detection systems

Commenter **Pipeline Safety Trust**

We support this proposal only because it provides some basis for enforcement, should PHMSA discover an operator outside HCAs without a functioning SCADA system or other system technically capable of detecting some leaks. However, without a definition or standard for such a system, it is difficult to imagine the existence of an operator who could not find some aspect of its operation to call a "leak detection system"

Definition of a leak detection system needed

There are three aspects of a review of hazardous liquid pipeline safety regulations that we feel should have been included in this rule, but are not: leak detection and valves; safety regulations for non-regulated gathering lines and gravity fed lines; and scope of high consequence areas, or more broadly, a review of what benefits integrity management programs bring to high consequence areas.	*Rule should address leak detection and valves*

Commenter **St Croix River Association (SCRA)**

The proposal [to expand the use of leak detection systems] is not accompanied by any required standard for the performance of leak detection systems. It also puts off addressing more stringent leak detection requirements for sensitive areas to a separate rule-making process, and puts off required valve installation (spacing and location) and minimum rupture detection standards to a separate rule-making.	*Recommends setting standards for performance of acceptable leak detection systems*

Commenter **State of Washington Citizens Advisory Committee on Pipeline Safety**

Further, we believe it is critical to address performance standards and criteria for leak detection systems in the first part of 2016. While there will be many other recommendations on the leak detection rulemaking, the importance of proper alarm management when operating leak detection systems is invaluable. Systems which have performed best during actual spills followed clear shutdown thresholds.	*Address standards for leak detection systems*

Commenter **State of Washington Utilities and Transportation Commission**

Further, the commission believes it is critical to address standards and criteria for leak detection systems in another rulemaking focused on leak detection in the first part of2016. While there will be many other recommendations on the leak detection rulemaking, the importance of proper alarm management when operating leak detection systems is invaluable. Systems that have performed best during actual spills followed clear shutdown thresholds.	*Include leak detection system standards*

Commenter **Western Organization of Resource Councils**

The provision does not establish a standard for the performance of any chosen leak detection system, and thus allows excessive discretion on the part pipeline owners and operators. We urge PHMSA to prescribe performance standards for required leak detection systems, including what type of systems must be used in sensitive areas, and to clearly define minimum rupture detection standards.	*Require performance standards for leak detection systems*

Subissue **Produced water**

Commenter **Alaska Wilderness League et al.**

According to the ANPRM, "Regulations associated with…statutory exemptions are not under consideration." In comments several of our organizations submitted to PHMSA on the ANPRM, we noted that this statement by PHMSA is problematic because the term "production" can and should be redefined administratively to address unregulated pipelines not integral to wells. In redefining "production" so it makes technical sense and only applies to pipes integral to wells and not to pipelines that transport materials, PHMSA easily could address the problem of federally-unregulated flowlines and produced water pipelines.	*Include three-phase flowlines and produced water pipelines in regulations*
Commenter **Dakota Rural Action**	
With regard to produced water pipelines, there is a general lack of regulation nationally. Much of the produced water moving through these lines is hazardous in the sense that when it reaches a waterway or the soil it can cause significant contamination.1 The large saltwater and produced water spills in North Dakota which have occurred with frequency in the past five years due to no state regulation could be avoided in the future if PHMSA regulates produced waste and saltwater pipelines by requiring minimum safety measures for such pipelines.	*Regulate produced water*
Commenter **Earthworks**	
Earthworks requests that PHMSA add produced water lines to the proposed rule.	*Add produced water lines to the rule*
Commenter **Kathy Hollander**	
Produced water lines should also have requirements and be covered by PHMSA rules.	*Regulate produced water lines*
Commenter **Pipeline Safety Trust**	
Safety Requirements for Currently non-regulated gathering lines and Produced Water lines (currently not covered by pipeline safety federal rules), but clearly within PHMSA's statutory authority	*safety requirements for non-regulated gathering lines and Produced Water lines*
Commenter **St Croix River Association (SCRA)**	
Requirements for produced water lines (currently not covered by federal pipeline safety rules).	*requirements for produced water lines*
Requirements for produced water lines (currently not covered by federal pipeline safety rules).	*Requirements for produced water lines*
Commenter **Western Organization of Resource Councils**	
With regard to produced water pipelines, there is a general lack of regulation nationally. Much of the produced water moving through these lines is hazardous in the sense that when it reaches a waterway or the soil it can cause significant contamination.5 Saltwater and produced water spills which have occurred frequently in oilfields in the Bakken and other basins in the past five years due to no state regulation would could be avoided in the future if PHMSA regulates produced waste and saltwater pipelines by requiring suitable safety measures for such pipelines.	*Regulated produced water*
Subissue **Public information**	
Commenter **County of Santa Barbara**	

In order to better inform the public, the County requests that more inforination be
posted on PHMSA's website including the results of pipeline inspection reports, notices of violations
and other reports and orders.

Provide more information posted on website including pipeline inspection reports, notices of violations, and other reports and orders

Commenter **Dakota Rural Action**

High Consequence Areas need to be made public knowledge
rather than kept confidential in the Emergency Response Plan. The public should be able to know what
areas have been determined potential High Consequence Areas in order to assess whether areas that
should be considered high consequence are not being considered as such by a pipeline company.

Make HCAs public knowledge

Commenter **Environmental Defense Center**

Hazardous liquid pipelines affect many communities, whether they are urban or rural. Public access to information about risks in their communities is critical. Following the Refugio Spill the history of recent inspections of the faulty Line 901 have been difficult to obtain, and even the regulating agency PHMSA does not always have access to all inspections from all the pipelines under its jurisdiction. There needs to be greater transparency and public access to information about pipeline safety. We strongly support the proposed National Pipeline Information Exchange ("NPIX"). Through this system, inspection reports, Integrity Management Plans, Corrective Action Orders and other information regarding the status and condition of pipelines can be readily available for PHMSA, other agencies, and the public to review. PHMSA should provide plain language versions of reports available to the public as well, i.e., short, easy to understand reports, in a standardized format.

Require posting of information to Agency website, including inspection reports, notices of violation, and other relevant reports and orders.

Commenter **The Michigan Coalition To Protect Public Rights-Of-Way**

All such failures require immediate emergent response from -local communities. Yet
local communities are presently kept entirely in the dark in any meaningful and impactful
way with respect to all relevant information, authority and resources regarding
hazardous pipeline regulation promulgation, planning, siting, installation, operation,
inspection, maintenance and even basic shut off locations, means and methods.
The geographic and political distance between the federal government and even state
government, from the local epicenter of disaster after disaster makes clear that the
entity expected to respond in such emergencies, must also be intimately involved from
the earliest planning stages of hazardous pipelines. This involvement must be much
more than a mere bystander. Local communities must be provided substantive legal
authority, jurisdiction and resources to work with the industry from planning and siting to
operation, inspection, maintenance and disaster response. This case is made even
more important as we observe the industry spending ever greater resources to attempt
incredibly, to spread blame to the same victimized local communities , when the industry
pipelines fail.

Provide local communities with relevant information, authority, and resources

Subissue **Scope of Annual Report**

Commenter **Pipeline Safety Trust**

One change we suggest that would at least allow PHMSA to gather some of the information necessary to investigate how IM is and is not working would be for PHMSA to require operators to include in its annual report the reasons for each repair (based on immediate, 270-day, 18-month, or other conditions) it was made and whether that repair location was inside or outside an area that could affect an HCA.	*Include the reasons and location (HCA or not) of repairs in operators' annual report*

Subissue **Unaddressed vulnerabilites and/or risk factors**

Commenter **Alliance for Great Lakes et al.**

Following the Marshall, Michigan, pipeline incident in 2010, the NTSB found that a key contributor to the challenge and inadequacy of initial spill response was the "[i]nadequate regulatory requirements for facility response plans under 49 CFR [§] 194.115, which do not mandate the amount of resources or recovery capacity required for a worst-case discharge." Unfortunately, with this NPRM, PHMSA has chosen to not address these pressing issues, which have remained outstanding for at least the past decade. Therefore, we strongly urge PHMSA to broaden the scope of its current rulemaking to include the spill response reforms necessary to ensure that the mistakes, lack of preparedness, and significant impacts witnessed during oil pipeline spills over the past five years are not repeated.	*Broaden scope to include spill response reforms*

Commenter **Pipeline Safety Trust**

Maintain Depth-of-Cover - Add requirement for depth-of-cover surveys to be performed everywhere (not just river crossings) a minimum once every 10 years, with the requirement to meet the minimum depth-of-cover requirements within 6-months after the discovery of shallower pipe cover (Keystone XL condition 19)	*requirement for depth-of-cover surveys everywhere at least once every 10 years*
Require that existing pipelines on crossings greater than 100 feet from high water mark to high water mark have depth of cover studies performed not less frequently than once a year. When such a study indicates that a pipeline or any part of it in sucha crossing of a water body is buried at less than 4 feet, require the reconstruction of the crossing, triggering the study and depth requirements to which new lines will be subject	*Requirements for existing pipelines that cross rivers*
Require each operator to complete a geomorphological study, including an assessment of the scour and channel migration potential at the location of the crossing, before construction of any crossing of a water body exceeding 100 feet in width from high water to high water . . . A new study must be performed whenever the segment in the crossing is to be repaired or replaced or whenever there are other nearby changes to the channel structure . . . That could affect the channel structure and depth at the crossing	*Require a gemorphological study to address river crossings*
PHMSA should require that every new, repaired or replaced crossing of every water body exceeding 100 feet in width from high water to high water be buried to a depth of not less than twice the depth determined by the most recent scour study to be the depth to which the river may scour. Whenever an annual depth of cover assessment reveals that the remaining cover is less than the most recent study's potential scour depth, the crossing must be reconstructed to bury the popeline to a depth to be determined by a new study.	*Depth requirements for river crossings*

Subissue **Valve standards**

Commenter **Accufacts**

Liquid pipeline valve basic selection, placement, and actuation decisions are first driven by the pipeline elevation profile, what I call the "soul of a liquid pipeline operation." From this basic information, additional considerations are incorporated on the elevation profile that may place further valves and change valve actuation selection for various reasons. All valve placements require proper surge analysis to assure each valve is safety incorporated into the pipeline's design and operation to avoid overpressure failure of the pipeline.	*Suggest valves be considered in a future regulatory process*

Commenter **Alaska Wilderness League et al.**

In addition to existing valve location requirements, we support new valve location requirements to ensure that important waterways, public lands, and subsistence areas are protected. These requirements are not in the NPRM even though the ANPRM asked for input on this issue. In order to protect waterways, it is critical to establish watershed protection requirements. Current valve requirements protect water crossings more than 100 feet wide, however we recommend requiring valves for pipeline crossings of all water crossings 25 feet wide or more and all feeder streams or creeks that lead to waterways 25 feet wide or more. PHMSA's rejection of such a requirement in the NPRM likely will result in unnecessarily large releases to smaller waterbodies, which have less capacity to dilute releases.	*Valve location requirements*

Commenter **Alliance for Great Lakes et al.**

PHMSA should also require the installation of remotely controlled valves on all pipelines. In September 2010, a leak from a natural gas pipeline in California was not halted until 90 minutes after it began. A subsequent investigation by National Transportation Safety Board ("NTSB") determined that the leak's effects could have been mitigated if EFRD technology such as automatic shutoff valves or remotely controlled valves had been installed.35 Remotely controlled valves allow for quicker responses to emergencies and are more effective response measures if operators are faced with conditions that may delay or prevent personnel from quickly accessing manual valves, such as adverse weather conditions.	*Require the installation of remotely controlled valves on all pipelines*
While PHMSA does provide general requirements for locations of valves,36 PHMSA should propose valve spacing requirements that provide more specific standards for pipeline operators to use in determining the maximum distance between valves. PHMSA claims that it will consider additional regulations for valve spacing in compliance with the Pipeline Safety Act of 2011. Any new valve location requirements should certainly be applied to newly built or replaced pipelines. In addition, these requirements should be applied to older pipelines within or near to HCAs. At a minimum, PHMSA should adopt a modified version of the ASME B31.4 industry standard of a 7.5 mile minimum between valves for pipelines carrying liquefied petroleum gas and anhydrous ammonia. In doing so, PHMSA should require that all segments of the pipeline comply with this valve spacing standard.	*Require valve spacing with specific standards*
We strongly urge PHMSA to include regulations requiring the installation of automatic shutoff valves for all pipelines, rather than for just those that are newly built or have been entirely replaced.32 PHMSA should not defer this until the future33 because a delay would perpetuate serious risks associated with the regulations requiring automatic shutoff valves. The May 2015 pipeline spill in California of more than 100,000 gallons of crude oil demonstrates the pressing need for automatic shutoff technology for all federally regulated pipelines.	*Require automatic shutoff valves for all pipelines*

PHMSA should issue new valve location requirements that protect water crossings less than 100 feet wide37 and consider extending such protection to crossings as little as 25 feet wide. We recommend that such valve placement requirements should also extend to pipeline crossings in feeder streams and/or creeks that lead to water crossings 25 feet or greater. If PHMSA plans to continue to use its >100-foot threshold, we nevertheless support valve requirements for the pipeline segments which cross feeder streams and/or creeks that lead to 100-foot crossings. By extending valve requirements to feeder streams and/or creeks, PHMSA more effectively protects the crossings to which it has already afforded a commitment of protection.	*Require valve location placement standards for water crossings*
Commenter **Audubon Society of New Hampshire**	
We are concerned that the proposed rules provide no clear standard for locations and types of shutoff valves, and strongly recommend that this issue be addressed.	*Include standards for locations and types of shutoff valves*
Commenter **Congresswoman Lois Capps**	
Furthermore, automatic shutoff valves, while not addressed in this NPRM, must be addressed immediately, as this technology has the potential to greatly reduce the frequency and severity of future spills.	*Address automatic shutoff valves*
Commenter **County of Santa Barbara**	
The proper location and frequency of valves is critical for minimizing pipeline leaks and ruptures, and protecting environmentally sensitive areas and areas of local significance. The County suggests that regulations mandating valve installation be revised to require coordination be.tween PHMSA, pipeline operators and local government entities when determining the location and frequency of valves in HCAs, coastal zones, and areas of local significance.	*Regulare location and frequency of valves*
Commenter **Environmental Defense Center**	
Finally, we urge PHMSA to address valve installation (spacing and location) now, rather than later. PHMSA should ensure that automatic shutoff valves are placed at shorter intervals in instances where pipelines are transporting hazardous liquids, where there are increased public health risks, and where pipelines are near environmentally sensitive areas.	*Address valve installation re: spacing and location*
Commenter **Janet Alderton**	
Although a leak detection system may be required, spills are limited not only by timely detection, but by the ability to isolate the damaged section of the pipeline with shut-off valves. Spacing and location of shut-off valves are not included the proposed rules. Manually operated shut-off valves cannot not adequately control the release of hazardous materials.	*Require standards for spacing and location of shut-off valves*
Although a leak detection system may be required, spills are limited not only by timely detection, but by the ability to isolate the damaged section of the pipeline with shut-off valves. Spacing and location of shut-off valves are not included the proposed rules. Manually operated shut-off valves cannot not adequately control the release of hazardous materials.	*Require remotely-operated shut-off valves*
Commenter **Judy Skog**	
There MUST be a clear standard of where and what shutoff valves will be used.	*Require standard for shutoff valves*
Commenter **Kathy Hollander**	

Shut off valve requirements and their minimum spacing should also be specified, including such factors as topography, water sources, and maximum spacing in all areas.	*Define shutoff valve requirements and spacing*

Commenter **Pipeline Safety Trust**

a clear standard for where and what types of Shut Off Valves should be required	*where and what types of Shut Off Valves*
There are three aspects of a review of hazardous liquid pipeline safety regulations that we feel should have been included in this rule, but are not: leak detection and valves; safety regulations for non-regulated gathering lines and gravity fed lines; and scope of high consequence areas, or more broadly, a review of what benefits integrity management programs bring to high consequence areas.	*Rule should address leak detection and valves*

Commenter **Sharon Natzel**

Another concern that needs to be addressed in the rule is that safety valves need to be placed on both sides of a pipeline crossing a waterway in which the water flowing is used for drinking water such as the Mississippi River. In addition, valves need to be placed on both sides of a waterway in which the water flows into a town or city downstream based on time constraints so that response to a spill or leak from a pipeline is required in far less time than it takes the water from an extreme rainstorm to reach the town or city.	*Address safety valves*

Commenter **St Croix River Association (SCRA)**

The proposal [to expand the use of leak detection systems] is not accompanied by any required standard for the performance of leak detection systems. It also puts off addressing more stringent leak detection requirements for sensitive areas to a separate rule-making process, and puts off required valve installation (spacing and location) and minimum rupture detection standards to a separate rule-making.	*Recommends requirements for spacing and location of valves*
A clear standard regarding where and what types of shut off valves should be required.	*Standards for where and what types of shut off valves should be required*

Commenter **Tip of the Mitt Watershed Council**

Oak Ridge National Laboratory conducted a study that concluded "installing ASVs and RCVs in pipelines can be an effective strategy for mitigating potential consequences of unintended releases because decreasing the total volume of the release reduces overall impacts on the public and to the environment." Given this conclusion, it is highly unfortunate that the current rulemaking will not address the use of automatic or remote controlled shut off valves as well as spacing requirements.	*Define where and what types of shut off valves are required*

Commenter **Western Organization of Resource Councils**

Presently there are no clear standards for where and what types of shut off valves must be required on pipelines. Shut off valves are a necessary piece of equipment to mitigate a spill when it is occurring. We urge PHMSA to develop clear guidelines outlining when companies must employ shut off valves on their lines, as well as what types of valves must be used.	*Define where and what types of shut off valves are required*

Issue ID **2.1** **Costs-Benefits**

Subissue **Benefits understated/overstated in RIA**

Commenter **Texas Pipeline Association**

TPA has concerns with the flas in the RIA in this docket on this proposed change. With regard to cost, the RIA assumes that these inspections are already being performed and that the rule change will result in little additional expense to operators. If this is the case, there is no need for the rule change. With regard to benefits, the RIA claims benefits as if no inspections are being performed at this time.	*Clarify issue with whether inspections are already being performed and the impact on benefits*

Subissue **Costs understated/overstated in RIA**

Commenter **American Petroleum Institute (API) & Association of Oil Pipe Lines (AOPL)**

In fact, industry experience illustrates that the cost and time burdens associated with the proposed requirements for gravity and rural gathering lines alone greatly exceed the aggregate cost estimate cited by PHMSA in the NPRM. One operator recently identified and mapped its gathering lines to obtain centerline data only; that is, their effort did not include efforts to collect detailed information about the lines (e.g., pipe specifications, pipe grade, specified minimum yield strength, etc.,). The effort cost about $1,000 per mile and averaged a timeframe of one month per one hundred miles. The operator reports that it has only a few hundred miles of gathering lines. In the NPRM, PHMSA stated that there are "approximately 30,000 to 40,000 miles of onshore hazardous liquid gathering lines in the United States." Extrapolating the cost data provided by the operator and the mileage estimate supported by PHMSA, identifying and mapping gathering lines for onshore hazardous liquid gathering lines would, at a minimum, cost $30 million. Based on this information, the cost of collecting centerline data alone will far exceed the $22.4 million estimate provided by PHMSA. [API-AOPL] •Miles of pipes is understated: "The inaccurate cost burdens associated with this proposed requirement are also illustrated with data from API's Pipeline Performance Tracking System, which is a voluntary initiative that provides meaningful data that allows operators throughout the industry to identify leading indicators and learn from them to prevent safety incidents. According to those operators contributing to the PPTS data for 2014, there are a total of 7,106 miles of gathering lines not subject to Part 195. PHMSA reported a total of 3,794 miles of regulated gathering lines in 2014." [API-AOPL]	*Gathering line cost analysis understates compliance costs*
[re. Offhore Pipelines:] Much of the offshore pipeline mileage that is regulated by PHMSA is non-HCA mileage… The technology does not currently exist to perform an ILI inspection for some offshore pipelines... In addition to technical challenges, the costs associated with mobilization and execution of an ILI run offshore are exponentially greater than those for similar projects conducted onshore… The cost data alone suggest that the single operator would incur costs that exceed the total industry aggregate cited by PHMSA in the NPRM. The Associations respectfully request, therefore, that PHMSA take into account the full cost impact of completing inspections on all of the non-HCA pipelines in the final rulemaking. [p.13] While offshore pipeline operators are fully committed to pipeline safety and zero spills, the cost-benefit of requiring these inspections offshore is particularly difficult to justify when comparing these exceedingly high costs and technical challenges to the number of incidents that actually occur offshore due to causes targeted by these types of assessments. Of the 1887 pipeline incidents reported to PHMSA from 2010-2014, only 15 occurred offshore, releasing less than 90 barrels, with most of those barrels originating from a single release caused by outside force damage. This is less than 0.01% of the total incidents for this time period. [API-AOPL]	*2. Non-HCA analysis understates compliance ocsts for offshore pipelines*

	[re. Gathering and Gravity Lines:] While the industry supports improving pipeline safety through inspection of the lines not currently in the Integrity Management Programs, it is worth pointing out that the cost-benefit analysis provided by PHMSA for this provision is neither accurate nor complete. In addition to the cost figures cited above for offshore pipelines, PHMSA does not examine the impact of the provision on gathering lines in its Regulatory Impact Analysis (RIA). Instead, PHMSA bifurcates pipelines into either 24-inch pipe or 8 to 10 inch pipe (RIA, page 56). PHMSA acknowledges that the smaller diameter pipes will likely undergo pressure testing, which according to PHMSA's estimates (Table 12) is considerably more expensive on a per mile basis than ILI testing. However, based on the pipe sizes provided, it appears PHMSA does not examine the costs for gathering lines, which are defined in Section 195.2 as having an outside diameter of 8-5/8" or less. These costs could significantly impact the economic viability of the wells the gathering lines service, so it is imperative that this be considered. Moreover, PHMSA does not estimate whether the benefits for this class of pipelines are greater than the costs. Gathering lines may exhibit significantly different rates of incidents and volumes lost per incident than transmission lines. Good policy making requires that the costs and benefits of the rule on offshore and gathering lines be adequately examined. At a minimum, the final rule should allow a longer implementation time to come into compliance to account for the uncertain nature of the ratio of costs to benefits. [p.15]	
	The Associations respectfully request, therefore, that PHMSA take into account the full cost impact of completing inspections on all of the non-HCA pipelines in the final rulemaking. [p.14]	*PHMSA underestimated the costs of inspections.*
	While offshore pipeline operators are fully committed to pipeline safety and zero spills, the cost-benefit of requiring these inspections offshore is particularly difficult to justify when comparing these exceedingly high costs and technical challenges to the number of incidents that actually occur offshore due to causes targeted by these types of assessments. Of the 1887 pipeline incidents reported to PHMSA from 2010-2014, only 15 occurred offshore, releasing less than 90 barrels, with most of those barrels originating from a single release caused by outside force damage. This is less than 0.01% of the total incidents for this time period. And the incident rate is similarly low historically with most offshore pipeline failures coming from hurricane damage. Offshore operators request some provisions for engineering and risk based decisions regarding assessing offshore pipelines to prevent misdirecting disproportionate valuable resources from higher risk/higher consequence lines to very low risk/low consequence lines.	*Benefits (small number of releases) do not justify the costs of the rule*
	Commenter **Offshore Operators Committee**	

As such a majority of the offshore pipeline network would be affected by this rule change. The offshore world has unique and different threats than pipelines onshore and presents particular challenges to integrity assessment. ILI technology is challenged by the wall thickness of these pipelines, the intense pressures at the seafloor, availability of space on platforms for accommodating longer smart tools, and other challenges. Offshore, something as simple as locating and retrieving a stuck pig will be an intense and costly research project so extreme care must be exercised when selecting tools. Currently, there are a limited number of vendors that have tools that can meet these challenges. In fact, there are some pipelines where the technology doesn't currently exist to perform an ILI inspection. Operators will need adequate time to work with vendors to schedule and perform these inspections. Hydrotests are also problematic in that they require production platforms to be shut in during preparations and testing, disposal of hydrotest water is difficult unless it can be pushed all the way onshore, and diving work often has to be done to properly isolate the pipeline.	*Cost-benefit analysis for periodic assessments of pipelines that are not already covered under the IM program requirements understates costs.*

Commenter **Texas Pipeline Association**

TPA has concerns with the flas in the RIA in this docket on this proposed change. With regard to cost, the RIA assumes that these inspections are already being performed and that the rule change will result in little additional expense to operators. If this is the case, there is no need for the rule change. With regard to benefits, the RIA claims benefits as if no inspections are being performed at this time.	*Clarify issue with whether inspections are already being performed and the impact on costs*
RIA on this rule change [assessment of non-HCAs pipelines] is flawed with regard to the cost to operators. The RIA utilizes the estimate of non-HCA pipeline mileage assessed by operators in a 2011 API survey to reduce the mileage assumed to be impacted by the proposed rule change. TPA believes this approach improperly understates the cost of the propsed change.	*Understates costs of non-HCA assessments*