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U.S. Department of Transportation
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Dear Sir or Madam:

Thank you for the opportunity to comment on the proposed rule amending the hazardous liquid pipeline regulations. The Trust is pleased to see the proposed changes, which we hope will result in safer hazardous liquid pipelines.

Prior to going through our specific comments on the regulatory changes proposed, we’d like to discuss the scope of this rulemaking. 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 the scope of high consequence areas, or more broadly, a review of what benefits integrity management programs bring to high consequence areas.¹ What troubles us perhaps more, is that in this rulemaking and its associated documents, there is no concern or curiosity expressed by the federal pipeline agency over recent incident data that suggest there is something fundamentally wrong with the integrity management program as implemented today: significant incidents on hazardous liquid lines within HCAs are on a rising trend over the past several years. Yet in this five year long effort to produce a proposed major rule on hazardous liquid pipeline operations, PHMSA doesn’t raise any concerns over the fundamental regulatory structure for these lines, even though IM as implemented by operators appears to be failing in many instances. See the graph on the following page that was created using PHMSA data available through October 2015. NTSB in their 2015 safety report of Integrity Management of gas transmission pipelines in HCAs² noted several shortcomings of the way the industry has implemented Integrity Management for those pipelines, and the data suggests that those shortcomings and probably others also apply to hazardous liquid pipelines.

Even the possibility of re-defining where integrity management rules should apply – the definition of HCAs – is put off until some undefined later time. And put off – again – ostensibly because PHMSA has yet to produce a report required by the 2011 Reauthorization Act on whether IM requirements should be expanded. Contrary to PHMSA’s inference that the completion of the report is necessary before rules can be proposed, the Act allows final rules to be promulgated on this issue 3 years after enactment of

¹ See references in the Federal Register notice for this proposed rule (pages 61625 and 61621).
the 2011 Act, regardless of whether a report is written. See 2011 Act, Section 5(f). Further, nothing in the Act has prohibited the agency from producing proposed rules at any time, nor from undertaking the kind of public conversation engendered by the publication of a proposed rule for comment.

It is imperative that PHMSA develop and publish such a report and issue a proposed rule on this subject. If there is something wrong with IM as designed or implemented, or if improvement is a matter of needing more enforcement to encourage compliance, we all need to know. The inquiry, the investigation, the analysis and public conversations need to happen. The data trends have been going up for the duration of the time this proposed rule has been under consideration. Further delay is unacceptable.

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 made and whether that repair location was inside or outside an area that could affect an HCA. This data would provide a leading indicator of what kinds of repairs are being made, identifying areas where additional inspections may be necessary or additional prescriptive regulations may be required to avoid failures. Congress directed the Secretary to "collect any relevant data necessary to complete the [integrity management] evaluation required" by the 2011 Act, a direction which should eliminate the need for any elaborate process to obtain permission to gather information from operators.

Following are our comments, which articulate both the strengths and shortfalls of the proposed rule from our perspective.
Extending Certain Reporting Requirements to All Hazardous Liquid (HL) Lines

We strongly support the added reporting requirements for gravity fed lines and gathering lines, requiring those operators who are not already required to do so to submit annual reports, incident reports, and safety related condition reports. We would like to see this reporting extended to require submissions to NPMS for geographic information system mapping purposes. Further, 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.

Inspections of Pipelines in Areas Affected by Extreme Weather, Natural Disasters, and Other Similar Events

The new regulation as proposed would require an operator to inspect a pipeline segment that was potentially affected by an extreme weather event, a natural disaster, earthquake or other similar event within 72 hours after the end of the event or sooner if the pipeline can be safely inspected earlier. In cases where an operator would not otherwise have inspected its at-risk pipeline, this proposal may help to mitigate damages caused by extreme weather events or other disasters, and might conceivably prevent some failures where such an event creates an unsafe condition that has not yet damaged the pipeline in the ensuing 72 hours. However, the proposal will not resolve the still-outstanding issue of pipelines being damaged at river crossings and operators having too little information about the risks presented by those crossings. Those risks exist independent of any extreme weather event or other natural disaster.

While we support this proposal, we note that it is reactive instead of proactive, and does very little, if anything, to prevent failures from such events. The types of river-crossing failures cited in the narrative explanation for the proposal, like the two Yellowstone River spills, the Spectra gas line rupture in Arkansas, and others would often not be prevented by these new rules. Those failures stem from operators' failures to construct pipelines to sufficient depth, or their failures to adequately integrate the threat of river scour, including ice scour, into their construction, operation, and inspection plans. The sediment bed load of rivers can be moved slowly, over time, in the absence of any extreme weather event, or it can move very quickly in the event of a flood or change in the river channel. Better risk analysis and mitigation for earthquakes, is another related issue that analysis and preparation varies greatly from operator to operator, and would also not be addressed by these after-the-fact inspections. Clearer requirements for analyzing and integrating the pre-event mitigation of such risks needs to be built into the Integrity Management requirements, and we ask that you do that as part of this rule.

We suggest three additional changes to address the risks of river crossings cited in the proposal's narrative:

1) 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 per year. When such a study indicates that a pipeline or any part of it in such a 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.

2) 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. The study must be submitted to and retained by PHMSA and retained by the operator. 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 (e.g. a bridge construction or removal, installation or removal of a pipeline, channel migration, etc) that could affect the channel structure and depth at the crossing.

3) 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 pipeline to a depth to be determined by a new study.

Additionally, for water crossings less than 100 feet in width from high water to high water, PHMSA should establish appropriate analysis and burial cover requirements to ensure that those waters are not impacted by avoidable pipeline ruptures at the crossings. Most everyone realizes that the 100 foot span is an arbitrary number that does not really define waterways that may be prone to dangerous scouring, so PHMSA should include analysis and burial requirements for smaller streams that may be affected by scour.

We also note that 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 also necessary for an operator to determine when the proposal's 72-hour maximum period for assessment begins or ends.

Useful definitions for this regulation could come from the “Severe Weather” definitions from the National Oceanic and Atmospheric Administration’s National Weather Service (NWS). NWS defines severe weather by type, including local storms, winter storms, flooding, and various hazards; and NWS offices put out Severe Weather Potential Statements and Severe Weather Statements to alert the public and state/local agencies to the potential or follow-up information for severe weather up to 24 hours in advance and while occurring.

In fact, 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.

**Requiring Periodic Assessments of Pipelines That Are Not Already Covered Under the Integrity Management (IM) Program Requirements**

Much of the ANPRM talked about the expansion of Integrity Management beyond HCAs. While we are pleased to finally see a proposed change that would require inspections of HL pipelines outside of HCAs, this alone is not an expansion of Integrity Management. Integrity Management is based on risk assessment and then an inspection system that identifies and mitigates of the identified risks, yet we see no corresponding requirement in this proposed rule for threat identification or risk assessment and no evidence of why the 10-year timeline was chosen. We recommend these lines also be inspected on the existing 5-year timeframe; given that this requirement is solely for inspection, and not for the full Integrity Management program that must accompany the inspection analysis of pipelines affecting
HCAs, the 10-year timeline seems insufficient. The shorter inspection period would lead to a higher likelihood of being able to catch potentially dangerous anomalous conditions within a timeframe that could prevent failures.

PHMSA uses this proposed expansion of pipeline inspections to justify not changing the definition of HCAs at this time, saying the pipelines outside HCAs will be safer; yet there is not justification presented for the 10-year timeframe demonstrating that it will in fact prevent incidents and keep these pipelines safer. Any increased attention will likely lead to the prevention of some failures, however we know that many anomalies progress much faster than a 10-year timeframe. While PHMSA is proposing to require periodic inspections, there is no accompanying language that this inspection must be based on threat identification or risk assessments, and perhaps be done on a more frequent basis depending on the results of these risk assessments. There is also no recognition or correction to possible problems with existing Integrity Management where data indicates that the rate of failures in HCAs is higher than the failure rate outside of HCAs. The National Association of Pipeline Safety Representatives (NAPSR) had commented and PHMSA had verified during the Advanced Notice of Proposed Rulemaking comment period that some pipeline operators currently turn off inspection tool capacity when outside HCAs. Yet this proposed requirement to conduct periodic inspections still would not preclude operators from turning off certain tool capacity outside of HCAs. If the ILI tool is equipped with the capacity to look for crack defects, that inspection capacity should continue once outside an HCA area. Also, if additional risk assessment capacity is needed based on an assessment of different risks and threats to that section of pipeline outside an HCA, tools must be used with the corresponding capacity to assess these different risks. Without specifically requiring a risk assessment, pipeline operators are not required to inspect these pipelines outside HCAs more frequently, even if anomalous conditions might indicate that it is wise to do so.

We suggest the newly proposed § 195.416 be changed as follows:

(b) General. An operator must perform an assessment of a pipeline at least once every 5 years, or as otherwise necessary to ensure public safety. The assessment must be comprised of an analysis of the risks facing that pipeline, including but not limited to all those described in § 195.452(e), and any information known by the operator that is listed in § 195.452(g)(1), and a comparison of those risks and description and implementation procedures for mitigating the risks; in addition to a physical assessment performed in accordance with section (c).

(c) Method. The physical assessment required under paragraph (b) must be performed with an inline inspection tool or tools capable of detecting corrosion and deformation anomalies, including dents, cracks, gouges, and grooves. If the tool is capable of detecting additional anomalies, that detection capacity will remain in effect as well (i.e. not be turned off) when physically assessing the pipeline segments. Exceptions may be allowed if an operator:....

Modifying the IM Repair Criteria and Applying Those Same Criteria to any Pipeline where the Operator has Identified Repair Conditions

This would expand the requirement that pipeline operators take certain actions after the discovery of a pipeline repair condition to pipelines outside of an HCA, and modify the criteria for pipelines that could affect an HCA.

We are pleased to see specific criteria and timetables for the repair of pipeline anomalies outside of
HCAs, and are pleased to see the justified expansion of ‘immediate repair’ conditions for pipelines within areas that could affect an HCA.

We have several concerns about this subject area, however. 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 grow and lead to pipeline failures, and hence we suggest the current immediate repair condition based on 80% corrosion is not conservative enough to prevent failures. We suggest the percentage be changed to 60% for immediate repairs, and 30% for longer-term repairs, or another conservative percentage based on careful analysis of these types of failures.

We are also concerned about the newly proposed timetables for repair. We acknowledge the reasoned evidence given for the new 270-day condition, and the elimination of the 60- and 180-day condition categories. However we did not see any evidence given for the 18-month and ‘reasonable’ timeframes added for repairing pipelines outside of HCAs. These outside HCA pipelines are referred to as being ‘noncritical’ and therefore, we presume, not in need of timely repair. Yet the conditions listed are serious anomalies that justify – based on a reasoned analysis of how quickly the anomalies may result in failure – a 9-month repair timeline within HCAs. Without a significant look at the definition of HCAs and public involvement in their determination (discussed elsewhere in these comments), there are arguably many areas outside of HCAs that deserve heightened protection, and an 18-month timeline is simply too long.

Because of the additional time allowed (increased by 50%) to address top- and bottom-side dents on the pipeline within areas affecting HCAs, we suggest that those dent thresholds be changed accordingly.

In addition, 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 § 195.452 removes important code language regarding pipeline repairs. There are a number of ways to correct this oversight – either by changing § 195.422 as we suggest below (and adding the reference back into § 195.452(h)(1)), or by adding the language directly into § 195.452(h)(1) where it was referenced but is shown as removed in the proposal.

We suggest the proposed code be changed as follows:

195.422  (a) Scope. [REMOVE SUBSECTION (a) AND RE-NUMBER] ....

(d) Remediation schedule. The scope of this subsection applies to pipelines that are not subject to the integrity management requirements in § 195.452. An operator must complete....

(1)(i) Metal loss greater than 60% of nominal wall regardless of dimensions. ... 

(3) 9-month repair conditions....

(3)(vi) Predicted metal loss greater than 30% of nominal wall that is located....

(e) Other conditions. The scope of this subsection applies to pipelines that are not subject to the integrity management requirements in § 195.452. Unless another timeframe....

195.452(h)(1) General requirements..... [CHANGE LAST SENTENCE AS FOLLOWS] An operator must comply with all other applicable requirements in this part in remediating a condition. An operator must comply with the applicable sections of § 195.422 when making a repair.

(h)(4)(i)(A) Metal loss greater than 60% of nominal wall regardless of dimensions. ...
(h)(4)(i)(B) A calculation of the remaining strength of the pipe shows a predicted burst pressure less than 1.2 times the maximum operating pressure at the location of the anomaly.

(h)(4)(i)(D) A dent located...with a depth greater than 4% of the nominal diameter.

(h)(4)(i)(C) A dent located...with a depth greater than 4% of the pipeline’s diameter.

(h)(4)(i)(E) An area of general corrosion with a predicted metal loss greater than 30% of nominal wall.

(h)(4)(i)(F) Predicted metal loss greater than 30% of nominal wall that is located.

We also note that currently hazardous liquid transmission line operators do not report the causes of specified condition repairs on their annual reports; they simply report the numbers of anomalies or conditions and mileage inspected inside HCAs. We strongly urge PHMSA to begin collecting detailed information about these conditions both within and outside of HCAs so that the agency, operators and public can better understand the anomalies that lead to these conditions and more accurately work to prevent them. The draft changes to the annual report do not currently reflect this as they should, and the information collected about the repairs should be as detailed for areas outside HCAs as it is for those areas affecting HCAs.

Expanding the Use of Leak Detection Systems to all Hazardous Liquid Pipelines

This proposal amends CFR 195.134 and CFR 195.544 to require all hazardous liquid pipelines transporting liquid in a single phase (without gas in the liquid) to have "a system" for detecting leaks.

The Regulatory Impact Analysis of this proposal prepared for PHMSA indicates that this is a proposal with few anticipated costs and benefits, chiefly because most HL pipeline operators already operate SCADA systems to manage their pipelines both within and outside areas that could affect HCAs. Since SCADA systems are nominally able to detect some leaks, those existing SCADA systems would be sufficient to comply with both existing and proposed regulations.

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." Industry frequently describes their required aerial right of way inspections and the presence of operator personnel engaged in repairs or maintenance on their systems as parts of their leak detection system. Without any regulatory limitations on what can be considered "a system", this proposal provides very few, if any, benefits to public or environmental safety.

What this proposal, which was five years in the making, makes even more obvious is that in spite of clear Congressional and public concern regarding the current state of leak detection requirements and the capacity of existing technology in the field, PHMSA has proposed only this current proposal which fails to make improvements over the status quo and apparently intends to do no more. Five years have elapsed since the ANPRM indicated PHMSA would take up the issue, four years since the last reauthorization act directed PHMSA to issue a report on leak detection within one year and follow that report after a year's Congressional review period with new regulations on leak detection. PHMSA says on its website that

the required leak detection report was sent to Congress in December of 2012, yet states in this NPRM that it has not yet done so, and suggests that the missing report and congressional review period are the reasons that this proposed rule does not include leak detection standards. Although the NPRM refers to taking up the issue in a later rulemaking (after the report and the review period), the title of that future rulemaking refers only to "rupture detection" according to the Secretary’s web page, not leak detection, leading us to the conclusion that PHMSA has absolutely no intention of taking up the issue of leak detection systems at any foreseeable time. This, in spite of the agency’s apparent knowledge of the harm that even small leaks left undetected can do: two leaks in the Salt Lake City area, cited in the NPRM narrative, caused substantial environmental and health impacts to the area’s residents; the West Shore leak in Wisconsin polluted many private wells, risking the health of the area's residents and requiring the expansion of a municipal water supply; the Tioga, North Dakota spill from a Tesoro pipeline has frequently been referred to as a leak, and it resulted in one of the largest inland oil spills in US history.

Leak detection is challenging technically, but that means that PHMSA should be using its regulatory authority to push the technology to improve, not accepting the status quo where up to 95% of pipeline failures are detected by something other than the operator's leak detection system (http://www.bloomberg.com/news/articles/2012-09-19/oil-pipeline-spills-go-undetected-by-much-touted-sensors). Moreover, 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 system (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 that operator’s worst case discharge in its facility response plan, not some fictitious unachievable best case.

**Increasing the Use of Inline Inspection Tools**

This change would require all pipelines that could affect an HCA to be able to accommodate inline inspection (ILI) devices within 20 years, and pipelines affecting newly-identified HCAs (after the 20-year period) would have 5 years to accommodate ILIs. We are pleased to see this proposed requirement, as ILI tools can theoretically detect anomalies that can then be repaired, but if left undetected may lead to pipeline failures. However, we are disappointed that this proposal applies only to pipelines affecting HCAs, and we see no detailed justification of the 20-year timeframe. We are also disappointed that the proposal delays the development of standards for ILI tools, including the detection of stress corrosion cracking, to a separate rulemaking.

As PHMSA points out, the discussion of this issue and existing regulations in § 195.120 stem from a 1988 law that encouraged the use of ILI devices and the modification of pipelines to accommodate the devices. At that time, there were no HCAs. Now, 25 years later, we see a proposed regulation requiring only those pipelines affecting HCAs to be able to accommodate ILI devices that will take effect in another 20 years. This is simply too little change and too much time allowed to implement it.

In addition, we note that the newly proposed § 195.416 will subject all HL pipelines to periodic inspections, yet approximately 13% of these pipelines cannot accommodate ILI devices. Perhaps PHMSA believes the requirement to use a method that provides “substantially equivalent understanding of the condition of the pipeline” will have the result of driving pipeline operators to modify existing pipes to
become piggable if possible, yet we think it would be better to expressly propose code language to this affect.

We recommend the code proposed in § 195.542(n) have a timeline for implementation of five years instead of 20. We also recommend expressly specifying that Close Integral Survey (CIS) results be integrated into ILI device findings. We recommend that § 195.120 be further modified from the proposal as indicated below, so that most HL pipelines (not just those affecting HCAs) will be able to accommodate ILI devices within the originally-proposed 20 year timeframe:

195.120 (a) General. Except as provided in paragraphs (b) and (c) of this section, each new pipeline and each main line section of a pipeline where the line pipe, valve, fitting, or other line component is replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices; and an operator must ensure that each pipeline is modified to accommodate the passage of an instrumented internal inspection device by [date 20 years from effective date of a final rule].

Clarifying Other Various Requirements

PHMSA clarifies various requirements throughout the proposal, many of which we think are critical to pipeline safety. We commend PHMSA for proposing these changes, and agree they are each justified and necessary. We strongly support that the proposed rule:

• Requires operators to develop IM plans before a pipeline is operational (currently not required until afterward).
• Requires operators to verify HCA designations on at least an annual basis.
• Requires annually verification that pipeline risk factors have not changed (for lines affecting HCAs), and if they have requires a new analysis.
• Specifies the need for operators to consider the accuracy (tolerance) of ILI tools when evaluating inspection results.
• Makes it clear that Integrity Management requirements apply to more than just line pipe (must include valves, etc.).
• Makes it clear that seismicity is a risk factor that needs to be considered as part of an IM program, and expands the list of information and attributes to be considered in the IM analysis, including the need to identify interrelationships affecting risk among the different data collected.

Shortcomings of this Rule

There are other improvements that are needed, but are absent from the rule. We ask that the following be added to this final rule:

• A clear standard for where and what types of Shut Off Valves should be required.
• 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.
• 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.

• Strengthen hydrotest requirements – including heightening both pressure and duration. (Keystone XL condition 22)

• 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)

• Cathodic Protection Improvements – Change § 195.563(a) to require operation not later than 6 months after the pipeline is constructed... (rather than 1 year); Add requirement for an initial Close Interval Survey within 1 year of the pipeline in-service date for new pipelines to confirm CP systems are working, and identify anomalies that must be corrected by improving CP and/or coating. (Keystone XL conditions 35, 37, 38)

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

• Increasing reporting requirements on the Annual Reports so the various anomalies identified and repairs made are categorized by cause, location (both by state and by whether in or out of an area that could affect an HCA), and assessment method so the public and regulators can better assess whether operators are making progress mitigating risks with their integrity management plans and whether varying state laws with respect to assessments affect incident rates into the future. The proposed changes to the Annual Reporting form in the NPRM docket do not require sufficient detail and should be revised.

We reiterate some of the issues addressed at the beginning of this letter. The Trust finds concerning and unreasonable that two important elements of the 2011 Act required of PHMSA have not yet been completed: promulgating rules for both Integrity Management/HCA expansion and rules for leak detection. Specifically, according to references in the Federal Register notice for this proposed rule (see pages 61625 and 61621), two reports required of PHMSA by Congress prior to promulgating new rules have not been published, and PHMSA claims it is therefore unable to finalize new rules in these areas: High Consequence Area (HCA) boundaries/integrity management expansion and leak detection. Yet the "PHMSA progress tracker" on the agency website for tasks under the 2011 Act shows that the leak detection report was delivered to Congress in December of 2012. The review period called for in the 2011 Act, during which the Secretary is not permitted to issue final regulations, ended more than two years ago.

As for the section dealing with the possible expansion of integrity management beyond existing high consequence areas, the tracker is similarly confusing: it reports the publication of this NPRM as progress under a gas transmission provision, and indicates that all other work is still "in progress", presumably including the required report to Congress. The statutory review period ended 3 years after enactment of the 2011 Act, meaning PHMSA has been able to issue final rules on expansion of IM for more than a year, regardless of the lack of a report to Congress. At best, the confusion created by the inconsistencies
between the NPRM document and the progress tracker makes it very difficult for the public to determine what has in fact been completed, what PHMSA's ongoing work includes and how to comment on these topics in this rulemaking. At worst, it would appear that instead of embracing greater pipeline safety PHMSA has used these Congressional requirements as an excuse to delay moving forward on needed changes to defining the segments to which integrity management rules apply and standards for Leak Detection systems. With this rule more than five years in the making there was plenty of time to produce the Congressional reports, and incorporate findings into this rule or into separate rules. We urge prompt publication of any overdue reports, and no further delays in preparation of proposed and final rules on these topics.

Thank you again for this opportunity to provide input.

Sincerely,

Carl Weimer
Executive Director