

Liquid Integrity Management Rule Frequently Asked Questions

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LIQUID INTEGRITY MANAGEMENT RULE BASICS

1.1 What are the PHMSA's objectives for the Liquid Integrity Management rule?

The liquid integrity management rule has four primary objectives:

- accelerating the integrity assessment of pipelines in High Consequence Areas
- improving operator integrity management systems
- improving government's role in reviewing the adequacy of integrity programs and plans, and providing increased public assurance in Pipeline Safety

Last Revision: 10/22/01

1.2 Who must comply with the rule?

The Liquid Integrity Management rule, §195.452, applies to all operators of certain hazardous liquid pipeline facilities subject to Part 195 that could affect a high consequence area. The compliance dates for certain provisions are based on whether a particular pipeline was owned or operated by a company that had more or less than 500 total miles of hazardous liquid pipelines subject to Part 195 on May 29, 2001. These 500 miles need not be contiguous. With limited exceptions, every hazardous liquid pipeline segment that is subject to Part 195 as specified in § 195.1, and that can affect an HCA, regardless of length, is covered by the rule.

Pursuant to recently adopted regulations, the Liquid Integrity Management rule also applies to low- stress pipelines in rural areas that are located in or within ½ mile of an unusually sensitive area (USA) as defined in § 195.6; and operate at a pressure of i) less than or equal to 20% SMYS; or ii) if stress level is unknown or it is not constructed with steel pipe, a pressure equal to or less than 125 psig.

Last Revision: 5/10/12

1.3 Is integrity management simply inspection of pipe condition?

No. While periodically assessing the pipe condition and correcting identified anomalies is an important part of the rule, there are other important requirements. Operators must develop improved management and analysis processes that integrate all available integrity-related data and information and assess the risks associated with segments that can affect HCAs. Furthermore, operators must implement additional risk control measures if needed to protect HCAs. Examples of these additional measures include: enhanced damage prevention programs, reduced inspection intervals, corrosion control program improvements, leak detection system enhancements, installation of Emergency Flow Restricting Devices (EFRDs), and emergency preparedness improvements.

Last Revision: 2/18/03

1.3 What is a high consequence area (HCA)?

High consequence areas are defined in the rule as either:

- High population areas, defined by the Census Bureau as urbanized areas,
- Other populated areas, defined by the Census Bureau as places that contain a concentrated population,

- Unusually sensitive areas, or
- Commercially navigable waterways.

Last Revision: 2/18/03

1.6 What are recognized industry practices?

Recognized industry practices include those found in national consensus standards or reference guides. Some standards currently invoked by Part 195 that are applicable to Liquid Integrity Management include, but are not limited to, NACE SP0502-2010; ASME/ANSI B31G-2004; and ASME/ANSI B31.4-2006.

Last Revision: 8/31/16

1.6 When can an operator use an alternative to a recognized industry practice?

An operator may elect to use an alternative to a recognized industry practice for any of several reasons. For example, an alternative practice could utilize new technology, such as a new generation of internal inspection device that has improved detection capabilities. An alternative technology could also be one that has been successfully used in other countries or by other pipeline companies but has not yet been codified into a national consensus standard. PHMSA Pipeline Safety wants to encourage operators to use innovative practices that are based on sound engineering judgment. Use of such alternatives helps improve the state-of-the-art in Pipeline Safety technology. The rule requires that the selection of an alternative must be based on a reliable engineering evaluation. Use of an alternative must provide an equivalent (or better) result than using the recognized practice. An operator must document its use of an alternative practice when the operator makes the decision to use the alternative.

Last Revision: 2/18/03

1.7 What was DOT's purpose for creating an Appendix C rather than placing this material in the regulation?

Part 195 Appendix C was created to provide additional guidance and clarification for selected requirements in the rule. This was provided to assist operators in understanding the basic rule requirements and what might be necessary for compliance. Because the information in Part 195 Appendix C is guidance, it was determined that an Appendix was the appropriate location for this material.

Last Revision: 10/23/01

RULE APPLICABILITY

2.1 Does the rule apply to more than line pipe?

Yes. The continual evaluation and information analysis requirements of the rule apply to pipelines as defined in 49 CFR 195.2. This includes, but is not limited to, line pipe, valves and other appurtenances connected to line pipe, metering and delivery stations, pump stations, storage field facilities, and breakout tanks. The baseline integrity assessment and periodic re-assessment requirements apply only to line pipe.

Last Revision: 2/18/03

2.2 Does the rule apply to low-stress lines?

Yes. The Liquid Integrity Management rule applies to certain low-stress pipelines as required by §§ 195.1 and 195.12.

Last Revision: 5/10/12

2.2A What are Category 1, 2, or 3 under the low-stress pipelines in rural areas, §195.12?

A pipeline category under §195.12 is determined by the nominal diameter and whether the pipeline is located in or within 1/2 mile of an unusually sensitive area (USA). If the pipeline is equal to or more than 8.625 inch in nominal diameter and located in or within 1/2 mile of a USA, it is Category 1. If the pipeline is less than 8.625 inch in nominal diameter and is located in or within 1/2 mile of a USA it is Category 2. A pipeline of any nominal diameter not located in or within 1/2 mile of a USA is Category 3. Category 1 and 2 pipelines must comply with Integrity Management requirements according to the dates specified in § 195.12.

Last Revision: 7/2/15

2.3 Do the requirements of the rule apply to “idle” pipe?

(Deleted. See PHMSA Advisory Bulletin ADB-2016-05, Pipeline Safety: Clarification of Terms Relating to Pipeline Operational Status, 81 FR 54,512 (Aug. 16, 2016))

Last Revision: 8/31/16

2.4 Does the rule apply to offshore pipelines?

Yes. The rule applies to those segments of offshore pipelines that could affect HCAs, principally commercially navigable waterways and unusually sensitive areas.

Last Revision: 10/22/01

2.5 What is meant by ‘operator who owns or operates a total of 500 or more miles of pipeline’ in 195.452(a)? For example, if an operator who operates more than 500 miles of pipeline also owns a small percentage of a small pipeline (less than 500 miles) that is operated by a different organization - does that smaller operator have to comply with the deadlines for category 1 pipelines, even if its O&M manual, management processes, etc. are totally separate from the large operator?

(Deleted. Applicable time frames for categorizing pipelines has passed.)

Last Revision: 7/2/15

2.6 If the operator of a small pipeline system is partially owned by another company, who is responsible for preparing the Baseline Assessment Plan and complying with the provisions of this rule - the operator, or the company that is part owner?

Any and all owners and operators of a pipeline facility are responsible for the facility’s compliance with applicable pipeline safety regulations. Normally, the primary operator will prepare the Baseline Assessment Plan under the requirements in §195.452 (c). Operators (or owners) may use outside resources, including adopting management plans prepared by parent companies, but that does not relieve the operator (or owner) of responsibility for having a Baseline Assessment Plan.

Last Revision: 2/18/03

2.7 If a company acquires additional pipeline in late 2001 that increases its total mileage over 500, are they covered by the rule? Are the compliance deadlines the same?

(Deleted. The timeframes for completing Baseline Assessments for operator size Category 1 and 2 pipelines has passed. Re-assessment schedules are now set based on the completion dates of baseline assessment and previous re-assessments.)

Last Revision: 7/9/02

2.9 If a pipeline subject to 195.452 is sold, does the new operator 'inherit' integrity management plans and deadlines from the original operator?

No. Acquisition of a pipeline by an operator includes accepting obligations attendant upon that pipeline as a result of regulatory requirements. For purposes of integrity management, an operator acquiring a pipeline would be expected to integrate that pipeline into its integrity management program. Multiple, independent integrity management programs are neither required nor desirable.

Compliance deadlines established in §195.452 for identifying segments that can affect HCAs have passed for all categories of pipeline, and all hazardous liquid pipeline segments that can affect HCAs should now have been identified. The acquiring company is, of course, responsible for the accuracy of its identification of segments that can affect HCAs and should assure itself that the identification performed by the selling company is adequate. The acquiring company should review and update the segment identification as it does for its other pipeline. The deadlines for completing Baseline Assessments continue to apply based on the category of the acquired pipeline, i.e., whether it was owned or operated on May 29, 2001, by an operator with more or fewer than 500 miles of pipeline.

Integration of new assets into existing Baseline Assessment Plans may result in realigning schedules for future assessments based on the relative risk of the acquired pipeline and the operator's existing pipeline(s). The regulatory deadlines for assessments (e.g., that re-assessments be scheduled within 5-year intervals) continue to apply, as well as the schedule requirements for any remediation required by §195.452(h) that may be pending at the time ownership of the pipeline is transferred.

Last Revision: 12/19/07

2.10 Who will be held accountable for implementing Integrity Management requirements in a case where an operator transfers ownership of pipeline assets to another company but retains responsibility, by contract, for maintenance and integrity management activities until some later date?

Any and all owners and operators of a pipeline facility are responsible for the facility's compliance with applicable pipeline safety regulations. An operator (or owner) may use outside resources including, in this example, contracting with the prior owner of the pipeline. In this example, PHMSA Pipeline Safety would likely inspect the operator's Integrity Management Program, including any activities conducted by contractors, but any enforcement action that results from noncompliance discovered during those inspections could be directed against either the operator, the owner, or both.

Last Revision: 2/18/03

2.11 If a pipeline transports both gas and liquids (e.g., some offshore lines), does the hazardous liquid integrity management rule apply, or does the gas integrity management rule apply?

Lines that transport both liquids and gas must meet requirements applicable to both. In practice, this means that the more stringent requirement must be met. (Note that the requirements for gas transmission

integrity management in Subpart O of 49 CFR Part 192 apply only if the pipeline is classified as a gas transmission pipeline).

Last Revision: 12/16/05

2.12 Does the rule apply to the operator of a marketing facility if that operator does not own or operate a pipeline but rather receives and delivers hazardous liquid from/to third-party pipelines?

Yes, if the facility is otherwise covered by Part 195. (The integrity management rule, by itself, makes no changes to the applicability of Part 195 rules). Since Part 195 applies generally to pipeline facilities, not just to line pipe, the requirements of §195.452 for HCA identification also apply to facilities that fall under Part 195 jurisdiction.

If the operator's facilities could affect an HCA, then the operator would be required to have an integrity management program that implements all applicable requirements of the rule including, the need to identify risks to the facility and take preventive and mitigative actions to reduce these risks.

Last Revision: 2/18/03

SEGMENT IDENTIFICATION

3.1 When must pipeline segments subject to the rule be identified?

(Deleted. The deadline for segment identification for operator sized Category 1 and 2 has passed.)

Last Revision: 5/10/12

3.2 Many operators have pre-defined segments on their pipeline (e.g., the length of pipe between two pump stations is considered a segment). When PHMSA Pipeline Safety refers to segments that can impact an HCA in the rule, in what context is the term segment used?

As used in the rule, a segment that can affect an HCA refers to a continuous portion of a pipeline system in which the released commodity from a failure occurring anywhere between the two end points of the segment could migrate to and affect an HCA. The segment sizes should be defined by whether or not a spill could impact the HCA and not by pre-set definitions used by the operator.

Last Revision: 2/18/03

3.3 How will an operator determine if a pipeline can affect an HCA?

Part 195 Appendix C of the rule provides guidance on factors an operator should consider in determining whether a pipeline can affect an HCA. An example is provided in the Appendix. The factors are:

- Potential physical pathways between the pipeline and the HCA.
- Terrain surrounding the pipeline. An operator should consider the contour of the land profile and if it could allow the liquid from a release to enter an HCA. An operator can obtain this information from topographical maps such as U.S. Geological Survey quadrangle maps.
- Drainage systems such as storm sewers, water crossings, small streams and other drainage systems that could serve as a conduit to an HCA.
- Crossing of farm tile fields. An operator should consider the possibility of a spillage in the field following the drain tile into a waterway.
- Crossing of roadways and railroad crossings with ditches along the side. The ditches could carry a spillage to a waterway.
- Potential natural forces inherent in the area (flood zones, earthquakes, subsidence areas, etc.)

- The nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly volatile liquids, etc.) Highly volatile liquids become gaseous when exposed to the atmosphere. A release could create a vapor cloud that could settle into the lower elevation of the ground profile.
- Physical support of the pipeline segment such as by a cable suspension bridge. An operator should look for stress indicators on the pipeline (strained supports, inadequate support at towers), atmospheric corrosion, vandalism, and other obvious signs of improper maintenance.
- Operating condition of pipeline (pressure, flow rate, etc.) and exposure of the pipeline to operating pressures exceeding the established maximum operating pressure.
- The hydraulic gradient of pipeline.
- The diameter of pipeline, the potential release volume, and the distance between the isolation points.
- Response capability (time to respond, nature of response).

Last Revision: 2/18/03

3.4 What is acceptable methodology and criteria for determining whether a segment could affect an HCA? (For example, what spill volume should be considered - Worst-case discharge? Most likely discharge? Most likely worst-case discharge?) Can an arbitrary safe distance be applied, or must location specific dispersion analyses be performed? Is air dispersion modeling expected or is spill trajectory adequate?

PHMSA Pipeline Safety expects each operator to develop a process for identifying what portions of its pipeline system could affect an HCA in the event of a failure. This process is a required Integrity Management program element per §195.452 (f). Operators are responsible for selecting a methodology and establishing any criteria needed to determine where pipeline failures could affect HCAs.

PHMSA Pipeline Safety will look for sound engineering judgment with a reasonable amount of conservatism to account for uncertainties in the assumptions and calculation methods used in the analysis. Operators should be able to justify the assumptions used in making these determinations.

Companies that apply an arbitrary “safe distance” should justify how this distance was determined and provide convincing evidence that this “safe distance” is indeed bounding for its pipeline system. Air dispersion should be considered in instances where hazardous material could be transported by air (e.g., failures of HVL lines).

For low-stress pipeline in rural areas that meet the requirements of §195.12, segments that could affect an HCA are those located in or within 1/2 mile of a USA or those determined by an analysis conducted in accordance with §195.452(a) that could affect an HCA.

Last Revision: 5/10/12

3.5 Do operators need to perform detailed consequence analysis to determine the specific impacts on population or USAs?

Yes. PHMSA Pipeline Safety expects that an operator will develop an understanding of the potential consequences of leaks and ruptures of its pipelines. The operator should be able to estimate the severity of releases in terms of volume of hazardous liquid that could be released, the physical pathways and dispersion mechanisms by which the commodity can be transported to an HCA, the amount of commodity that might actually reach the boundaries of the HCA, and the population and environmental resources that can be affected by such a release.

The operator should develop a sufficient understanding of the severity and impact of potential releases to determine the appropriate preventive and mitigative actions required by 452 (i).

Last Revision: 2/18/03

3.6 Can the identification of segments that “can affect” HCAs be refined after the December 31, 2001, (or November 18, 2002, as appropriate) deadline?

Yes. PHMSA Pipeline Safety recognizes that some operators used methods with conservative assumptions in identifying which pipeline segments can affect HCAs to meet the initial compliance deadline. Refinement of these segments, potentially changing the boundaries of identified segments, may occur as more detailed analyses are performed later.

This refinement process could result in a conclusion that some segments (or portions of segments) identified by the deadline cannot, in fact, affect an HCA. PHMSA Pipeline Safety expects operators to document their justification for any such elimination of an identified segment and may review the technical basis for these changes during inspections.

The refinement process could also result in identification of new segments that can affect HCAs, not included in those identified initially. PHMSA Pipeline Safety would not consider failure to identify such segments by the deadline to be a noncompliance unless there is a pattern demonstrating significant weaknesses in the process used to identify segments by the deadline. Newly-identified segments must be scheduled for baseline and re-assessment in accordance with the provisions of the rule.

Operators should not apply refinements which impact the definition of a segment that can affect an HCA once the process of conducting the baseline assessment for that segment has begun. The baseline assessment results must be evaluated, and repairs required by the criteria of paragraph (h) must be performed, for the entire segment as defined prior to conduct of the assessment. The boundaries of the segment can be reconsidered after conclusion of the baseline assessment and repair process. The results of the assessment should be taken into account, as appropriate, in such reconsideration.

For new pipelines (i.e., operator size Category 3), PHMSA Pipeline Safety expects that segments that can affect high consequence areas will have been identified when the pipeline begins service. Subsequent refinement would not be expected to occur unless driven by outside circumstances (e.g., growth of a populated area).

Last Revision: 2/18/03

3.7 How will HCAs be identified and communicated to the industry?

PHMSA Pipeline Safety has developed a GIS dataset showing the locations of HCAs (as defined in §195.450) throughout the nation. This data is available to operators via the National Pipeline Mapping System.

Last Revision: 5/21/12

3.8 What are PHMSA Pipeline Safety expectations for operators to determine new or changed HCAs?

The One Rule requires operators to develop their own HCA dataset and use it in their IMP.

Last Revision: 5/21/12

3.9 When must newly-identified HCAs be included in the program?

Over time, new HCAs may be identified as population distributions change, or new drinking water or ecological resource data becomes available. Newly identified areas must be incorporated into the Baseline Assessment Plans within one year of identification. PHMSA Pipeline Safety will periodically update the HCA maps and make them available on the National Pipeline Mapping System for operator use. The operator reporting requirements, the information to be updated, and the frequency of updates can be found at <https://www.npms.phmsa.dot.gov/>

Operators must also look for new HCAs on their own by monitoring local population growth or through knowledge of environmental resources that becomes available to them. In either event, a newly- identified HCA must be incorporated into the integrity management program within one year of its identification. A baseline assessment for pipeline segments that could affect newly identified HCAs must be performed within five years of its identification.

Last Revision: 12/16/05

3.10 On what frequency or schedule will changes to the HCA maps on the National Pipeline Mapping System be made? Will PHMSA Pipeline Safety announce or provide public notice of changes?

Information on the frequency or schedule for changes to NPMS can be found at <https://www.npms.phmsa.dot.gov/>.

Last Revision: 5/10/12

3.11 How will PHMSA Pipeline Safety track changes to HCA information over time? When data fields are changed, will operators be able to clearly distinguish the new information from the old in NPMS?

PHMSA Pipeline Safety uses version numbers in naming HCA data layers. Visual comparison of different versions of the layers will reveal any differences in geographic information.

Last Revision: 2/18/03

3.12 If OPS did not complete the Unusually Sensitive Area (USA) mapping for a state by December 31, 2001, what responsibility does an operator have to identify segments that could impact USAs in that state? Similarly, for those states for which the USA mapping was not completed until late 2001 (e.g., final quarter CY2001), will OPS grant some relief from meeting the December 31, 2001 segment identification requirement to operators with pipelines in those states?

(Deleted. See <https://www.npms.phmsa.dot.gov/> for PHMSA's plans for updating NPMS for USAs.)

Last Revision: 5/10/12

3.13 For those states in which USA maps are not posted until after December 31, 2001, how long does an operator have to incorporate this new information into its segment identification and assessment planning process?

(Deleted. See <https://www.npms.phmsa.dot.gov/> for PHMSA's plans for updating NPMS for USAs.)

Last Revision: 5/10/12

3.14 If an operator desires location and other information on a specific ecological or drinking water USA to use in risk analysis and determination of potential pipeline release impacts, how can this information be obtained?

Those operators who desire to make accurate determinations of whether their system can affect a particular USA can obtain more specific information on the location of particular USAs from their drinking water providers and state heritage networks. Contact information for a particular USA is included in the USA data layers that operators can obtain from PHMSA Pipeline Safety. GIS-related software will be required to view this information. PHMSA Pipeline Safety will not act as an agent for purposes of gathering additional information.

Last Revision: 2/18/03

3.15 Since the USA data in the National Pipeline Mapping System (NPMS) contains buffer zones around the actual drinking water or ecological resource, is it possible that an operator's evaluation to determine whether a spill could impact an HCA might show a release reaching a USA depicted on the NPMS map when in reality such a release might not actually reach the sensitive area?

Yes. In mapping USAs in the NPMS, buffers were used to account for the uncertainties in the species or drinking water location data. Thus, it is possible that spills "just reaching the edge" of a USA boundary (for instance) might not actually impact the drinking water or ecological resource. Those operators who desire to make accurate determinations of whether their system can affect a particular USA can obtain more specific information on the location of particular USAs by contacting the entities that supplied the drinking water and ecological data to PHMSA Pipeline Safety. Operators can find contact information for these drinking water and ecological data suppliers by clicking on the USA in the NPMS.

Last Revision: 2/18/03

3.16 What mechanism is available for questioning or challenging HCA and USA identification once such identification has been posted on the National Pipeline Mapping System?

HCAs and USAs have been defined in Part 195. These definitions were developed after considering significant public and industry input, and they are now final. PHMSA Pipeline Safety is using recognized organizations and data sources for mapping HCA information. Anyone having new information that they believe could affect the accuracy of the mapped HCAs (e.g., errors in data sources, or more recent data) should contact PHMSA Pipeline Safety.

Last Revision: 10/22/01

3.17 Must non-pipe elements of a pipeline system that can affect HCAs (e.g., stations and facilities) have been identified?

Yes. While the assessment requirements of 49 CFR 195.452 are applicable to line pipe, all other requirements, including segment identification, are applicable to the entire pipeline system as defined in 49 CFR 195.2. PHMSA Pipeline Safety expects operators to understand which pump stations, terminals, and other facilities might also affect HCAs in the event of a failure.

Last Revision: 2/18/03

3.18 If an operator initially treated its entire system(s) as having the potential to affect an HCA (to meet the 12/31/01 deadline for segment identification) and then includes its entire system in its Baseline Assessment Plan, can they later refine this approach by defining only specific, smaller segments that can affect an HCA (e.g., when it comes time to make repairs after a tool run, or for the purposes of evaluating the need for EFRDs)?

(Deleted. An operator, with justification, can refine its segment identification; however, an operator must implement the requirements of the Liquid Integrity Management rule as the segments are defined at the

time an assessment is complete. For example, an operator cannot redefine segments after an assessment is complete for the purposes of not performing repairs.)

Last Revision: 12/6/02

3.19 What types of considerations would PHMSA Pipeline Safety consider reasonable for determining whether pipelines can affect commercially navigable waterways in open water?

PHMSA Pipeline Safety has elected to use the National Waterways Network database as the basis for identifying commercially navigable waterways in National Pipeline Mapping System. This database includes commercially navigable waterways in open water (i.e., offshore or in the Great Lakes) and those that are inland (rivers, canals, harbors, etc.). Vessels that use commercially navigable waterways in open water, typically called fairways, can be rerouted. Pipeline spills in such areas may therefore have a limited impact on commerce. This is not the case for inland waterways or for specific routes that provide sole access to a port (e.g., where water depth may limit ships to a specific approach), or where for other reasons vessels cannot be diverted.

PHMSA Pipeline Safety recognizes that other databases may provide waterway information that is more comprehensive. Such information may be used by operators in evaluating whether a specific pipeline system could affect a high consequence area. Operators may make reasonable distinctions for commercially navigable waterways in open water based on whether or not shipping could be rerouted. If a spill from a particular segment of pipeline would not be expected to interfere with commercial navigation, then operators may conclude that the segment cannot affect a commercially navigable waterway. Operators must still consider whether spills could affect other HCAs (e.g., drinking water intakes on the Great Lakes).

Operators may consult with agencies such as the U.S. Coast Guard and the U.S. Army Corps of Engineers for additional or more comprehensive information for conducting risk assessments. Such agencies can provide guidance on whether specific routes provide sole access to a port.

Last Revision: 2/18/03

3.20 What assumptions would PHMSA Pipeline Safety find acceptable for analysis of spilled product transport by waterway or topographical features?

Because the physical characteristics near pipelines can vary dramatically, PHMSA Pipeline Safety does not believe that any single set of assumptions would be applicable in all cases. For example, waterways may be broad, slow-moving rivers or fast-moving mountain streams. Topography near a pipeline can vary between a flat prairie and steep gullies. Ground cover can also affect the speed of product transport. Operators are responsible for considering the specific circumstances of their pipeline in the vicinity of high consequence areas and determining the analytical assumptions that are appropriate. Operators are expected to consider the effect of extreme conditions (e.g., floods), and to use recognized sources for data regarding stream flow rates, etc. Operators should assure their analyses are reasonably conservative. PHMSA Pipeline Safety may review the technical basis for these assumptions during integrity management inspections.

Last Revision: 2/18/03

3.21 Why is it important that operators know the specific characteristics of high consequence areas their pipelines can affect?

Operators need to know the characteristics of HCAs that their pipeline can affect to make decisions required by the integrity management rule. For example, the type of HCA can affect the consequences of a leak or rupture, and thus affect the relative risk ranking of a segment. The type of HCA, or even the

specific ecological resource involved in a USA, could affect decisions regarding preventive and mitigative measures.

Last Revision: 10/12/02

3.22 The National Pipeline Mapping System (NPMS) does not contain maps for ecological USAs in Pennsylvania. Are operators responsible for identifying USAs in Pennsylvania?

Yes. Operators are responsible for having identified all pipeline segments that could impact HCAs in all states in which they operate, regardless of whether all of the HCAs have been mapped on NPMS. In those situations where USA maps are not available on NPMS, operators may use ecological and drinking water information used to prepare and maintain their spill response plans, as well as other resources from local and state agencies available to them to identify these USAs.

Last Revision: 12/16/05

3.23 Must concentrations of an operator's own personnel, e.g., a work camp, be considered high consequence areas?

Yes. The integrity management rule states that "other populated areas" are included in the definition of high consequence areas. "Other populated areas" are defined in §195.450 as "a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial areas." If the Census Bureau delineates work camps or other areas containing concentrations of an operator's personnel as a Census Designated Place (treated as "other populated areas" in the HCA definition), they are clearly covered under the rule.

Section 192.452(d)(3)(i) also requires that "When information is available from the information analysis...or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in §195.450 of a ... other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area...." Thus, operators who are aware that work camps or other concentrations of their employees would meet the definition of other populated areas must also treat them as high consequence areas, regardless of whether they are listed on Census Bureau or NPMS maps.

Last Revision: 9/21/04

3.24 Can operators exclude pipeline from consideration under the integrity management rule on the basis that any effect it could have on a high consequence area is small?

No. Section 195.452(a) specifies that the rule applies to "...each hazardous liquid and liquid carbon dioxide pipeline that could affect a high consequence area...." The rule does not provide for excluding any pipeline based on the magnitude of the potential effect. Any pipeline segment that could affect a high consequence area is subject to the rule.

Last Revision: 9/21/04

3.25 Must I assume that a leak from a propane pipeline can affect drinking water USAs?

No. Operators can assume that propane is not soluble and will not affect drinking water supplies.

Last Revision: 9/21/04

3.26 What HVLs should be assumed to affect drinking water?

The effect of HVLs on potential could affect an HCA segment can be found in Report TTO1, "Consequences of HVL Releases," dated December 31, 2002. The report is on the PHMSA public website at <https://www.phmsa.dot.gov/pipeline/hazardous-liquid-integrity-management/hl-im-key-documents>.

Last Revision: 5/10/12

BASELINE ASSESSMENT PLANS

4.1 What is an assessment?

As used in the rule, assessment constitutes all of the actions that must be performed to determine the condition of the pipe. This includes conducting one or more internal inspections (e.g., metal loss plus geometry tools), performing hydrostatic tests or external corrosion direct assessment, or using other technology that provides an equivalent understanding of the condition of the line.

Any anomalies identified by the assessment that meet criteria in §195.452(h) must be remediated in accordance with the schedules in that paragraph, but these remedial activities are not considered part of the assessment.

The interval in which a pipe segment must be re-assessed is considered to start with the end of field activities of an assessment. For ECDA, this corresponds to the date when the last direct examination is made.

Last Revision: 12/16/05

4.2 What must be in the Baseline Assessment Plan?

The Baseline Assessment Plan must include a written plan for performing the baseline assessments necessary to assure pipeline integrity for each pipeline segment that could affect an HCA. It must include:

- Identification of all the pipeline segments that can affect an HCA
- The integrity assessment method, or methods, planned for use on each identified pipeline segment
- A schedule for assessment of each identified segment
- An explanation of the technical basis for the integrity assessment method(s) selected and the risk factors used in scheduling the assessments.

Last Revision: 2/18/03

4.3 Under what conditions should the Baseline Assessment Plan be modified?

The Baseline Assessment Plan must be modified whenever there are changes to the pipeline segments that can affect HCAs. For example, if an operator identifies a new HCA through the monitoring its right-of-way or through information analysis [as required by §195.452 (d) (3)] and determines that portions of its pipeline can affect this HCA, this newly identified pipeline segment must be included in the Plan.

Pipeline that can affect newly-identified HCAs must be included in the Baseline Assessment Plan within one year after their identification. These pipeline segments must be assessed within five years of their identification.

The Baseline Assessment Plan should also be modified if the operator gains knowledge from the initial (baseline) assessments that leads to a change in inspection priorities, assessment methods, or other improvements to its program. The operator must document Plan modifications and the reason(s) for the changes. This documentation must be available for PHMSA Pipeline Safety review during an inspection.

Last Revision: 2/18/03

4.4 When must baseline assessments be completed?

(Deleted. Applicable time frames for completing baseline assessments have passed.)

Last Revision: 7/2/15

4.5 How do the required dates for completing 50 percent and 100 percent of assessments apply to a category 2 pipeline that is acquired by an operator that had more than 500 miles of pipeline on May 29, 2001?

(Deleted. Applicable time frames for completing baseline assessments of Category 2 pipelines have passed.)

Last Revision: 7/2/15

4.6 Can assessments performed before the effective date of the rule be relied on as baseline assessments?

(Deleted. The timeframe for use of prior assessments has passed.)

Last Revision: 5/10/12

4.7 What must an operator consider in prioritizing pipe segments for assessment and re-assessment?

The risk posed by each pipeline segment covered by this rule must be considered in scheduling baseline assessments and periodic re-assessments. In scheduling assessments, an operator must consider all risk factors relevant to that pipeline segment. The rule requires that the following factors be included:

- results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;
- pipe size, material, manufacturing information, coating type and condition, and seam type;
- leak history, repair history, and cathodic protection history;
- product transported; operating stress level;
- existing or projected activities in the area;
- local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic);
- transport to HCAs through storm sewers, water crossings, indirect transport through streams, ditches and water bodies;
- roadway and railroad crossings;
- geo-technical hazards; and
- physical support of the segment such as by a cable suspension bridge.

Additional factors relevant to particular pipelines should also be included. Examples are provided in Part 195 Appendix C of the rule.

Last Revision: 10/22/01

4.8 The rule does not require the Baseline Assessment Plan to be developed until March 31, 2002; however, integrity assessments performed since January 1, 1996 can be used to satisfy the baseline integrity assessment requirement. Will operators be penalized for using prior assessments as a baseline assessment if their risk analysis determines that some of these

segments may be lower risk than segments which have yet to be assessed?

(Deleted. The time frame for use of prior assessments has passed.)

Last Revision: 5/10/12

4.9 Will operators need to seek waivers from PHMSA Pipeline Safety in order to change assessment schedules after the initial Baseline Assessment Plan has been developed?

No. PHMSA Pipeline Safety understands that there are a number of factors that could result in the need to modify Baseline Assessment Plans after their initial preparation. For example, as information is obtained from the initial integrity assessments, risk analysis, and operating experience, an operator's understanding about the specific integrity threats and relative importance of those threats may change. An operator may elect to apply a different integrity assessment method (e.g., select a different in-line inspection tool that may improve the capability to detect a particular type of defect), or perhaps accelerate assessments in some areas because the risks are higher than previously understood.

Assessment plans are likely to change, and §195.452 (c) (2) requires operators to document the basis for changes in the plan so these can be reviewed during inspections. It is not necessary to apply for a waiver to change the Baseline Assessment Plan. Even though an operator's plan may change, the operator must still complete baseline assessments by the deadlines specified in the rule.

Last Revision: 12/16/05

4.10 How will OPS view situations where a scheduled baseline assessment for a segment can't be performed in accordance with the schedule due to environmental permitting constraints or city moratoriums on street excavations? These delays cannot always be foreseen five years out. Will operators be allowed to conduct the baseline assessments "out of order" in these cases?

(Deleted. The time frame for completion of operator size baseline assessments for Category 1 and 2 pipelines has passed.)

Last Revision: 5/10/12

4.11 Should operators archive previous versions of their assessment plans so PHMSA Pipeline Safety can track changes to these plans over time?

No. PHMSA Pipeline Safety expects that changes to the Baseline Assessment Plan will occur as information is gleaned from the initial assessments, the integration of assessment results with other data, and operator risk analyses that utilize this new information. Operators must record and retain the technical basis for changes to their Baseline Assessment Plans. This information must be available for PHMSA Pipeline Safety review during inspections. While archiving previous versions of assessment plans is not required, an operator must have adequate documentation to show how the plans have changed and the technical justification for those changes.

Last Revision: 10/22/01

4.12 The rule requires that 50% of the line pipe that can affect HCAs must have been assessed by September 30, 2004 for category 1 pipe and August 16, 2005 for category 2 pipe. For purposes of determining the 50% mileage criteria, does an operator use the total mileage that has been and will be assessed, or just the mileage that has been determined as having the ability to impact an HCA? (For example, most operators who use internal inspection, will pig a greater distance than just the portion of the pipeline that can affect an HCA.)

(Deleted. The time frame for completion of baseline assessments for 50% of the line pipe that could affect an HCA had passed.)

Last Revision: 5/10/12

4.13 For purposes of meeting the deadlines for completing baseline assessments, is the date of the assessment considered to be the day when the tool run is complete, when the preliminary data is received, or when the evaluation of the in-line inspection results is complete?

The date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed, not including repair activities. That will be when a hydrostatic test is completed, when the last in-line inspection tool run of an integrated set of tool runs is performed (see FAQ 6.6), when the last direct examination associated with external corrosion direct assessment is made, or the date on which field activities for "other technology" for which an operator has provided timely notification is conducted.

Evaluation of the assessment results, integration of other information, and repair of anomalies must still be performed in accordance with the requirements established for these activities in the rule. This means that, in the event a series of ILI tool runs is used to complete an assessment, the 180-day discovery period for each individual tool run begins when that specific tool reaches the receiver if the tool provides sufficient information to determine if a particular repair criteria condition exists. These activities are considered to occur after the completion of the "assessment".

In those rare instances in which only a partial assessment is performed (e.g., in-line inspection system loss of power results in loss of data near the end of a pig run) operators will be expected to evaluate the results that were obtained within 180 days of the early termination, in accordance with §195.452(h)(2). If however, the quality of the partial data is suspect and an entire rerun is to be performed, then the evaluation will be expected within 180 days after the successful rerun.

Last Revision: 12/16/05

4.14 Must all of the highest risk segments have been assessed by September 30, 2004 for category 1 pipe (or August 16, 2005 for category 2 pipe), or will PHMSA Pipeline Safety allow operators some flexibility to deal with practical issues in scheduling assessments?

(Deleted. The time frame for the completion of the baseline assessments of highest risk segments has passed.)

Last Revision: 5/10/12

4.15 If an operator develops a single Baseline Assessment Plan that covers both intra- and interstate pipelines, does the need to complete assessments on 50% of the pipeline mileage that can affect HCAs apply to both intra- and interstate line segments, or just interstate line segment mileage? Should the company's Plan identify whether line segments are intra- or interstate?

Operators have the flexibility to prepare Baseline Assessment Plans to support their internal management processes and organization structure so long as the BAP meets the content requirements of the rule. The 50% requirement will apply to all pipeline systems that are covered under the rule - interstate and/or intrastate. Inspections for intrastate piping will be done by state agencies (if they are party to agreements with PHMSA Pipeline Safety).

To facilitate PHMSA Pipeline Safety and state Pipeline Safety program inspections, it is desirable that Plans indicate which line segments are intrastate and which are interstate. This information will help to focus inspection activities by states and PHMSA Pipeline Safety to appropriate pipe segments.

Last Revision: 12/16/05

4.16 What specific information from the company's baseline assessment plan does PHMSA Pipeline Safety expect to retain in its inspection files? For example, will PHMSA Pipeline Safety retain the boundaries of segments that could affect HCAs, the assessment methods for these segments, the dates on which these segments will be assessed, etc.?

To improve the ability to monitor operator implementation of their assessment program, and more efficiently prepare for future inspections, PHMSA Pipeline Safety may record basic information on operator integrity assessment plans, including:

- the location of segments that can impact HCAs,
- the assessment methods to be used for those segments, and
- the schedule for conducting these assessments.

Once baseline assessments have been conducted, PHMSA Pipeline Safety may also record general information about the condition of the segment and actions taken to mitigate anomalies, as well as schedules for subsequent assessments. This information may be retained in PHMSA Pipeline Safety's internal inspection records.

Last Revision: 10/22/01

4.17 If an operator has multiple pipeline systems and/or multiple business units, does PHMSA Pipeline Safety require the operator to produce a single Baseline Assessment Plan for the entire company, or can an operator create multiple plans to align with its operating units and internal management practices?

Operators have the flexibility to prepare Baseline Assessment Plans to support their internal management processes and organization structure. Thus, an operator with multiple pipeline systems could have one plan for each pipeline system, one plan for each business unit (or operating entity within the company), or a single plan covering all pipeline systems it operates. Each Baseline Assessment Plan must meet the requirements of §195.452 (c) and address all pipeline segments that can affect HCAs for the pipeline system(s) covered by the Plan.

Last Revision: 10/22/01

4.18 What specificity does PHMSA Pipeline Safety expect for schedules in baseline assessment plans?

PHMSA Pipeline Safety expects to see a viable, active planning and scheduling process that is likely to result in assessments being performed in the relative sequence identified by risk assessment. PHMSA Pipeline Safety will review an operator's process for managing its baseline assessment schedule. The degree of specificity of assessment schedules will vary depending on how far in the future assessments are planned but is generally expected to be something beyond a general reference to the planned year for assessments scheduled in the relatively near-term when practical vendor scheduling issues are involved.

Last Revision: 12/16/05

INTEGRITY ASSESSMENT INTERVALS

5.1 How often must periodic integrity assessments be performed on pipeline segments that can affect an HCA after the baseline assessment is completed?

Assessments must be performed at intervals determined by the operator based on segment-specific risk factors. Scheduled intervals must be no longer than 5 years (§195.452 (j)(3)) unless an operator has sound technical justification for a longer interval and notifies PHMSA Pipeline Safety of its intent to use the longer interval. Whatever interval is selected must be technically defensible.

Last Revision: 12/19/07

5.2 Does the requirement that an operator establish inspection intervals not to exceed five (5) years mean 5 calendar years (i.e., pipe assessed in 2003 must be re-assessed in 2008) or 5 actual years?

Re-assessments must be conducted within 5 actual years (not to exceed 68 months in certain cases - see FAQ 5.11). For example, a pipe segment assessed on March 23, 2003 has been re-assessed before March 23, 2008.

Last Revision: 12/19/07

5.3 Must operators conduct re-assessments before they have completed all baseline assessments?

Yes

Last Revision: 5/29/02

5.4 Can a re-assessment interval be scheduled beyond 5 years?

Yes. Re-assessment intervals can be scheduled beyond five years if a sound engineering evaluation combined with the use of other technology show the pipe to be in good condition and provide an equivalent level of understanding of pipe condition as internal inspection tools, pressure testing, or ECDA. Re-assessment intervals can also be extended if the integrity assessment technology most appropriate to examination of a specific pipe segment is not available. Operators must notify PHMSA Pipeline Safety whenever re-assessments are scheduled at longer intervals than 5 years. (See §195.452 (j)(4)).

Last Revision: 12/19/07

5.5 What is the mechanism for requesting adjustments to assessment intervals? Must operators apply for such adjustments?

(Deleted. See FAQ 5.4.)

Last Revision: 5/10/12

5.6 Can the operator use risk assessment data to defend longer intervals between integrity assessments?

Yes. The fundamental purpose of the rule is to improve protection in high consequence areas. Therefore, PHMSA Pipeline Safety expects strong risk-based arguments to be a primary component of technical justifications to schedule assessment intervals longer than 5 years.

Last Revision: 12/19/07

5.7 What would OPS view as acceptable criteria for assessment intervals longer than 5

years?

(Deleted. See FAQs 5.6 and 5.8.)

Last Revision: 5/10/12

5.8 The gas transmission integrity management rule includes a provision for waiver of reassessment intervals if necessary to maintain product supply. Is PHMSA Pipeline Safety considering/willing to extend the same or similar provisions to hazardous liquids operators? How would such considerations be handled?

No. PHMSA Pipeline Safety understands that practical considerations such as customer demands and meeting community energy needs will influence the scheduling of integrity assessments. Nevertheless, PHMSA Pipeline Safety expects operators to schedule and perform baseline and subsequent integrity assessments within the time frames required by the rule for all segments that can impact HCAs. Operators can, of course, always apply for a waiver to any specific requirement

Last Revision: 12/16/05

5.9 Once baseline assessments are complete, will operators be able to use their continuing evaluation process to identify primary threats and schedule assessments accordingly, even if this means conducting metal loss and deformation inspections on different intervals?

Yes. §195.452 (j) (3) requires operators to use their risk analysis, and analysis of results from the last integrity assessment to determine the appropriate interval for conducting future integrity assessments. Where internal inspection is the chosen assessment method, completing the re-assessment will require that both a metal loss and deformation tool be run. Either in-line inspection tool can be run more frequently if threats to pipeline integrity indicate that differing frequencies are appropriate. However, both tools must be run within the required re-assessment interval.

Last Revision: 10/23/01

5.10 What is the difference between the 'periodic evaluation' required by 195.452 (j) (2) and the process for determining reassessment intervals required by 195.452 (j) (3)?

The 'periodic evaluation' process is distinct from the reassessment interval process. Periodic 'evaluations' involve a different process than 'assessments.' Periodic evaluations are analytical reviews of a wide range of data and information regarding the pipeline integrity that includes but goes beyond simply 'assessment' results. 'Assessments' of pipelines on the other hand are tests, or actual measures of the pipeline's condition and can be performed using a variety of tools or inspection techniques.

As specified in §195.452 (j) (2), the continual evaluation must, at a minimum, consider the results of the baseline and periodic integrity assessments, risk analysis, decisions about remediation, and preventive and mitigative actions. The rule does not specify if the continual evaluation process should be stand-alone or combined with other integrity management program processes; this is left to the discretion of each operator. The frequency at which periodic evaluations are performed must all be determined as required by the rule. The requirements for establishing reassessment intervals are separate from those for periodic evaluations and are listed in §195.452 (j) (3).

Last Revision: 8/22/07

5.11 How does the 'not to exceed 68 month' assessment interval provision of the revised continual assessment interval requirement of 195.452 (j) (3) differ from the maximum 'five-year interval' for assessments?

The rule, as revised, requires that operators must establish (maximum) re-assessment intervals of five-years, 'not to exceed 68 months,' for continually assessing the line pipe's integrity. The additional 8-month allowance has been provided to provide flexibility to allow for unforeseeable events (e.g., permitting delays, weather, tool failures) that could affect the ability to successfully complete an assessment. Operators should continue to schedule assessments such that the normally determined assessment interval is achieved and should not utilize the 8-month allowance in their normal planning process.

Last Revision: 12/19/07

INTEGRITY ASSESSMENT METHODS

6.1 What are acceptable integrity assessment methods?

Internal inspection, hydrostatic testing, and external corrosion direct assessment are acceptable methods to assess pipeline integrity. For electric resistance welded (ERW) pipe or lap welded pipe susceptible to longitudinal seam failures, the method selected must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies. Other technologies that an operator can demonstrate provide an equivalent understanding of pipe condition may be acceptable methods. However, operators must notify PHMSA Pipeline Safety 90 days before conducting an assessment using other technologies.

Last Revision: 12/16/05

6.2 Are there different requirements for inspection of pipelines carrying highly volatile liquids?

No. The requirements applicable to these kinds of pipelines are no different than those that apply to other hazardous liquid pipelines. Those requirements include the need to consider risk factors applicable to specific pipeline segments. Pipelines such as these can involve unique risk factors, and the rule requires that these be considered in scheduling integrity assessments and considering the need for additional preventive and mitigative actions.

Last Revision: 10/22/01

6.3 Are there different requirements for inspection of overhead suspension pipeline bridges?

No. The requirements applicable to these kinds of pipelines are no different than those that apply to other hazardous liquid pipelines. Those requirements include the need to consider risk factors applicable to specific pipeline segments. Overhead suspension pipeline bridges can involve unique risk factors, and the rule requires that these be considered in scheduling integrity assessments.

Last Revision: 10/22/01

6.4 What kind of tool can an operator use to conduct integrity assessments by internal inspection?

The rule does not limit the type of tool or tools that can be used for internal inspection. Any tool(s) used must be able to detect corrosion and deformation anomalies, including dents, gouges, and grooves.

PHMSA Pipeline Safety expects operators to evaluate the segment specific risks associated with each portion of the line that could affect an HCA and determine the appropriate assessment technology or combination of technologies to confirm whether or not those specific threats are present.

For electric resistance welded (ERW) pipe or lap welded pipe susceptible to longitudinal seam failures,

the tool(s) must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

Last Revision: 10/22/01

6.5 What type of pressure test can be used to assess pipeline integrity?

The rule requires that pressure tests be conducted according to the requirements of 49 CFR Part 195, Subpart E. Operators choosing to assess by pressure test should also assure their corrosion control program is effective. PHMSA Pipeline Safety inspectors will pay particular attention to the adequacy of corrosion control programs for pipelines for which pressure testing is used.

Last Revision: 10/22/01

6.6 If an operator elects to use in-line inspection for satisfying its baseline assessment requirements, must a metal loss “smart” pig and a deformation tool both be run? If so, must these both be run at the same time, or can these runs be made at significantly different times?

Given the capabilities of current technology, an operator who elects to use in-line inspection will need to run two tools - a metal loss tool and a deformation device - to satisfy the baseline assessment requirements of §195.452 (c) (1). In most cases, PHMSA Pipeline Safety expects that these two tools should be run in a similar time frame to maximize the value of data integration. Furthermore, running the tools in close proximity allows the operator to readily identify potentially serious anomalies such as dents with metal loss. Assessments that consist of tool runs separated in time can be credited as baseline assessments in some circumstances. In the event that tool runs separated in time (by more than 30 days) are relied upon as baseline assessments, the completion of field activities for the first run will be considered as the date from which the required reassessment interval must be calculated. (See also FAQ 5.9.)

Last Revision: 8/18/05

6.7 Can internal inspection be performed using only a deformation tool if the analysis of the pipeline demonstrates that corrosion is not a primary integrity threat for a specific pipeline segment?

No. The rule requires that internal inspection be performed with a tool or tools capable of detecting corrosion and deformation anomalies. However, after conducting the baseline assessment, it is possible that an operator might determine that the interval between metal loss tool runs could be extended beyond the five-year reassessment interval if the assessment results review, data integration, and risk analysis demonstrates the line to be in good condition and corrosion is not a significant threat. In this case the operator would have to notify PHMSA Pipeline Safety of its intent to use an extended interval between metal loss tool runs, provide the technical basis for this determination, and describe the external monitoring activities that are in place to assure the pipe remains in good condition.

PHMSA Pipeline Safety will review the technical basis for such assessment intervals during inspections.

Last Revision: 2/18/03

6.8 Will PHMSA Pipeline Safety establish criteria for minimum acceptable in-line inspection tool capability? (E.g., are low resolution magnetic flux leakage tools acceptable or must high resolution tools be used?)

No. PHMSA Pipeline Safety expects operators to select the integrity assessment method(s) that provide confidence the location-specific integrity concerns of a given pipe segment will be identified if they are present. At this time, PHMSA Pipeline Safety does not intend to establish minimum criteria for in-line

tools. However, PHMSA Pipeline Safety will evaluate the operator's technical basis for selecting a method for integrity assessment. The in-line tool selection process should consider factors such as a tool's detection capabilities and limitations, the accuracy with which it can locate and size anomalies, and the confidence associated with the tool's measurements. As standards are published that address minimum requirements for in-line tool capability, PHMSA Pipeline Safety will use this information in its inspection guidance.

Last Revision: 2/18/03

6.9 For operators having line pipe in states that have a pressure testing requirement, will satisfying the state requirement also suffice for satisfying the integrity assessment requirement of the integrity management rule?

Yes, if the pressure test meets or exceeds the requirements of Subpart E, it will satisfy the integrity management rule. If a state's requirements are less (e.g., a shorter "hold" time), then the pressure test required by the state's regulation would not be satisfactory for compliance with §195.452 (c) (1) (i).

Last Revision: 10/22/01

6.10 What are the acceptable integrity assessment methods for ERW pipe or lap welded pipe susceptible to seam failure?

For ERW pipe or lap welded pipe susceptible to seam failures, an operator must:

- run an in-line inspection device(s) capable of detecting seam flaws, metal loss corrosion, and deformation anomalies, OR
- perform a Subpart E hydrostatic test.

In addition, as part of an effective integrity management program, PHMSA Pipeline Safety expects operators to determine and apply the most appropriate integrity assessment method or methods to address the specific integrity concerns of each pipe segment that can affect an HCA.

PHMSA Pipeline Safety will review operator integrity management programs to be sure the operator selects an appropriate method(s) for addressing the integrity concerns of ERW and lap welded pipe. Thus, if seam issues are a particular concern, PHMSA Pipeline Safety believes operators electing pressure testing as an integrity assessment method should consider the value of supplementing a subpart E test with a spike test. For operators selecting hydrostatic testing as an integrity assessment method, PHMSA Pipeline Safety will review the effectiveness of the operator's corrosion control program for those segments.

Last Revision: 2/18/03

6.11 What types of other technology can be used for integrity assessments other than internal inspection or pressure tests?

(Deleted. See FAQ 4.1.)

Last Revision: 5/10/12

6.11a Is the evaluation of seam 'susceptibility' a one-time determination?

No. Operators that have low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must choose an assessment method capable of assessing seam integrity. The determination of whether or not a specific pipeline seam is 'susceptible' can involve a variety of factors such as original pipe purchase specifications, incident history, operating pressure, prior pressure testing, pressure cycling, etc. Some of these factors may be operationally dependent and subject to change

during future pipeline operations. Thus, if the susceptibility determination is based on any factors that have the potential to change substantially over time (e.g., pressure cycling), a process should be in place to re-evaluate this determination on an appropriate interval.

Last Revision: 12/19/07

6.12 How does OPS intend to evaluate an operator's notification to use "other assessment methods", as allowed by 195.452 (c) (1) (i) (C)?

(Deleted. See FAQ 12.1.)

Last Revision: 5/10/12

6.13 How will OPS communicate information on "other acceptable technologies" [see 195.452 (c) (1) (i) (C)] to industry?

(Deleted. See FAQ 12.1.)

Last Revision: 5/10/12

6.14 Is the "spike" hydrostatic test an acceptable integrity assessment method, or must all hydrostatic testing conform with the requirements of subpart E?

(Deleted. See FAQ 6.5.)

Last Revision: 5/12/12

6.15 A reduction in operating pressure can provide an equivalent level of safety as that provided by a Subpart E hydrostatic test. Is a pressure reduction an acceptable integrity assessment method?

No. A pressure reduction is not an assessment method. Although a pressure reduction can provide an equivalent margin to failure as a hydrostatic pressure test, a pressure reduction provides no information about the condition of the pipeline. One of the primary objectives of this rule is for operators to obtain a better understanding of the condition of their pipe so they can make well-founded technical decisions to reduce risk and protect HCAs. Section 195.452 (h) (1) specifies that a reduction in operating pressure taken to provide an immediate improvement in safety cannot extend more than 365 days without the operator taking additional remedial action and notifying PHMSA.

Last Revision: 7/2/15

6.16 Will PHMSA Pipeline Safety allow liquid operators to use the Direct Assessment process allowed in the gas transmission integrity management rule as an acceptable "other technology" for integrity assessment [see 195.452 (c) (i) (C)]?

The rule was revised on October 25, 2005, (70 FR 61571) to add external corrosion direct assessment as an acceptable assessment method. This change became effective November 25, 2005.

Last Revision: 12/16/05

6.17 Can I perform an assessment using an MFL tool without also running a deformation tool?

Yes, if certain other actions are taken. MFL tools can detect the presence of dents, but not reliably size them. Thus, PHMSA Pipeline Safety considers that any indication of a dent found using an MFL tool is

potentially a defect meeting the repair criteria in the rule, until the contrary is demonstrated. PHMSA Pipeline Safety will accept an assessment conducted using an MFL tool without a concurrent deformation tool run if the operator specifically directs its ILI vendor to identify all potential dents. All such potential dents must then be excavated and examined, and those meeting rule repair criteria must be remediated. If all potential dents are not excavated, then a subsequent assessment using a deformation tool or hydrostatic test must be conducted on an expedited basis.

Last Revision: 9/21/04

6.18 If an operator chooses to assess its pipeline using external corrosion direct assessment (ECDA), does it have to use another assessment method to assess for deformation anomalies such as dents, gouges, and grooves?

Under the revised §195.452(c)(i), external corrosion direct assessment is considered one of the accepted assessment methods. No additional assessment tool/method is required unless the operator has low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure.

It should be noted, however, that ECDA may not be applicable to all pipelines. NACE SP0502-2010 Section 3.2.3 states “The data collected in the Pre-Assessment Step often include the same data typically considered in an overall pipeline risk (threat) assessment. Depending on the pipeline operator’s integrity management plan and its implementation, the operator may conduct the Pre- Assessment Step in conjunction with a general risk assessment effort.” In support of pipeline assessments, §195.452(g), Information Analysis, requires an operator to “analyze all available information about the integrity of the entire pipeline and the consequences of a failure.” If the information/risk analysis indicates that utilization of ECDA would not address major risks associated with a particular HCA-affecting segment of a pipeline (e.g., third-party damage or internal corrosion), then use of ECDA as the sole method of assessment for that segment may not be appropriate.

This is further amplified in Subsection 3.3.3 of NACE SP0502-2010 Section 3.3, ECDA Feasibility Assessment, which states that “If the conditions along a pipeline segment are such that indirect inspections or alternative methods of assessing integrity cannot be applied, this standard ECDA process is no longer applicable.”

Last Revision: 8/31/16

6.19 Are the direct assessment requirements contained in ASME B31.8S-2001 standard applicable to hazardous liquid pipelines?

No. ASME B31.8S-2001 is only applicable to natural gas pipelines. PHMSA decided not to cross-reference directly or indirectly ASME B31.8S–2001 in §195.588, because the document is closely identified with gas pipelines.

Last Revision: 10/23/06

6.20 Does the new rule, §195.588, permit operators to use direct assessment to address the threat of stress corrosion cracking?

If an operator chooses to use direct assessment to address stress corrosion cracking, the operator must notify PHMSA in accordance with the “other technology” provisions of §195.452(c)(i)(C). The changes to §195.452(c)(i) only added external corrosion direct assessment as an accepted method. PHMSA decided not to cross-reference directly or indirectly ASME B31.8S–2001 in final §195.588, because the document is closely identified with gas pipelines.

Last Revision: 10/23/06

6.21 Can an operator use an indirect assessment tool for ECDA that is not listed in Table 2 of NACE RP-0502-2008?

Operators are expected to follow the latest Standards invoked in §195.3.

Last Revision: 10/23/06

6.22 If you learn something in the post assessment step that may change the results in another ECDA, is there a time limit when you have to reassess that covered segment?

No. There is no specific limit on when an operator must reassess in these circumstances. Invalid results, however, can call into question whether an assessment was actually completed. Thus, operators may want to perform reassessment before the original reassessment interval expires, if still possible. In any event, PHMSA would expect operators to respond in a time frame that is commensurate with the importance of the potential problem that is identified.

Last Revision: 10/23/06

6.23 If Guided Wave UT is used as part of the ECDA process, is it considered 'other technology' requiring notification?

Yes. Use of guided wave technology, alone, as an examination method or as an alternative to excavating pipeline to conduct a direct examination would be considered "other technology" and would require notification prior to use.

If guided wave UT is used as one of the complementary tools for indirect inspections as part of ECDA, however, it would not be considered other technology. NACE SP0502-2010 lists some indirect inspection tools but notes that they are not the only tools that can be used. Rather, they are representative examples. "Other indirect inspection methods can and should be used as required by the unique situations along a pipeline or as new technologies are developed. [The operator must] assess the capabilities of any method independently before using it in an ECDA program" (3.4.3.2).

Last Revision: 8/31/16

6.24 For the first time using ECDA you are required to do an extra direct examination. Does this mean the "first time" on each covered segment, or the first time you do ECDA (ever)?

Yes. This provision and provisions in NACE SP0502-2010 requiring additional actions "when ECDA is applied for the first time" apply to the first application of ECDA in each Region containing HCA-affecting segment(s).

Last Revision: 8/31/16

6.25 Does close interval survey/overline survey qualify for 'other technology'?

No. These are indirect measurement techniques that can be used in ECDA. If used in that context, and in conformance with NACE SP0502-2010, these techniques would not represent "other technology".

PHMSA would not find them acceptable as assessment methods if used alone, outside the context of ECDA.

Last Revision: 8/31/16

6.26 At what point during ECDA does one move from severe, moderate, minor to immediate, scheduled, and monitored?

The categories of "severe", "moderate", or "minor" refer to the severity of indications (see Section 4.3 of NACE SP0502-2010). Each operator is responsible for determining these severities during the indirect inspection step. "Immediate", "scheduled", or "monitored" refer to the priority for excavation (see Section 5.2 of NACE SP0502-2010). After each indication has been categorized according to its severity, the operator is responsible for determining the urgency (prioritization) of excavation of indications for direct examination (see §195.588(b)(3)(iii)). Identified defects then must be scheduled for remediation (see §195.452(h)(3)), and classified as "immediate", "60-day", "180-day", or "Other" repair conditions (see §195.452(h)(4)). This classification must be done once the operator has sufficient information to "discover" remediable defects.

Last Revision: 8/31/16

6.27 What timeframes apply to "discovery" of conditions presenting a potential threat to the integrity of a pipeline when using Direct Assessment?

The rule requires that conditions presenting a potential threat to pipeline integrity be discovered as soon as the operator has enough information to do so (See §195.452(h)(2)). The rule also establishes a maximum time limit of 180 days after completion of the assessment to "discover" a condition presenting a potential threat to pipeline integrity. In the case of ECDA, the assessment is considered complete when the last Direct Examination is completed. However, because the direct examination provides the operator with specific, quantitative information about conditions presenting a potential threat to pipeline integrity, 'discovery' must be declared immediately upon completion of the direct examination. Therefore, for ECDA, the 180-day time limit to declare "discovery" of a condition potentially affecting the integrity of the pipeline identified during a direct examination is not directly applicable. (If an operator encounters unusual circumstances which indicate the need to delay declaration of "discovery" until significantly after completion of the direct examination, those circumstances, along with the action plan to obtain enough additional information to determine if a condition presenting a potential threat to the integrity of the pipeline has been "discovered," must be documented.)

Another consideration for ECDA is the time that is required to conduct the direct examinations after the completion of the indirect inspection step. Although both the rule and NACE SP0502-2010 are silent on this timeframe, PHMSA would expect that direct examinations be completed within a reasonable period of time after the completion of the indirect inspection step. PHMSA understands that operator need flexibility to deal with seasonal restrictions, weather, permitting, and other issues that impact scheduling direct examinations and repairs. However, PHMSA expects operators to be able to demonstrate continuing progress toward completion of the direct examinations. If an operator experiences delays interrupting continuing progress, PHMSA would expect an operator to document the reasons for the delays and take additional precautions, if necessary, to assure pipeline integrity until the direct examinations can be accomplished. PHMSA will review documentation related to the above issues during integrity management inspections to verify that the operator had a reasonable basis for delaying continuing progress and that as a result pipeline integrity was not threatened.

In addition, operators should note that the assessment is not completed until the last required direct examination is completed. Operators that delay completion of all direct examinations past the due date for completing the assessment may be out of compliance with assessment schedule requirements.

Last Revision: 8/31/16

6.28 What is the definition of complementary technologies for selection of ECDA indirect inspection tools?

The NACE standard SP0502-2010 describes complementary as: "the strengths of one tool compensate for the limitations of another." Generally, an operator should endeavor to use tools based on different

technologies.

Last Revision: 8/31/16

6.29 Can operators aggregate ECDA regions after the process is started and they determine that some regions have common features?

Yes, operators can aggregate ECDA regions if they have similar characteristics (See NACE SP-0502-2010, Section 3.5.1.2).

Last Revision: 8/31/16

6.30 What does PHMSA expect to see in an ECDA feasibility study?

PHMSA expects an operator's IM plan to document a process, and its records to document the implementation of that process, that integrates the information available about the pipeline to demonstrate that its conditions/characteristics are consistent with the operator's assumptions. For ECDA, this should include determining the practicality of using two complementary indirect examination tools, assembling information about the pipeline (including coating condition and cathodic protection experience) necessary to define Regions, and identifying areas where indirect tools may not provide accurate readings and determining how those areas will be handled.

Last Revision: 10/23/06

6.31 How can I demonstrate that I have applied more restrictive criteria the first time I used ECDA (required by 195.588(b)(2)-(4) and NACE-0502-2002)?

There are a number of ways in which operators can be more restrictive during first time use of ECDA. Operators must apply more restrictive criteria in the first three phases of ECDA (i.e., pre-assessment, indirect examination and direct examination). Examples of more restrictive criteria that could be used include but are not limited to:

- Pre-assessment
 - Making and/or segregating the HCA-affecting segment(s) into additional ECDA regions, which requires additional excavations
 - Perform test holes to obtain additional data on the pipeline and it's environment and soil conditions
 - Pre-marking the pipeline to enhance data integration such as putting flags or paint dots at regular intervals (e.g., 5 ft.) all along the pipeline
- Indirect examination
 - For paved areas, require boring to the subsurface soil to obtain readings
 - Use an additional tool, three instead of two, four instead of three, etc.
 - Establishing a severity table and apply increased severity for each tool result, such as:
 - For CIS any reading more positive than -0.95 vDC is a severe indication (even though the CP potential shows that the area currently has adequate CP).
 - For PCM the severe category is a 15% drop in signal within 1000', or 20% drop in 2000'. (Normally a 20% signal loss in PCM over 1000' would be severe).
 - Require closer distance between test point readings for possible greater accuracy and less chance of missing an indication
 - Increase the excavation priorities by categorizing the highest two coating fault indications be treated as immediate and all subsequent indications be scheduled no matter how minor they appear.
 - Compare readings and results with all history and if even if not a close match, make the indication more severe.
 - For indirect survey tool conflicts, even if resolved, redo indirect inspections for all tools.

- Direct examination
 - Provide a larger excavation to assure all nearby indications are discovered to eliminate the potential of major indications masking minor or less severe indications
 - Requiring additional testing and/or NDE results be obtained before closing excavations (such as Magnetic particle, X-ray and UT readings on all suspected indications, seams and welds)
 - Based on what is discovered in the initial direct examination, increase the urgency of all remaining indications.
 - Increase the urgency of repair criteria to repair/replace noncritical defects
 - Examine areas that in the past have been problematic regardless of current indications (additional excavations required)
 - Implement root cause fix on all pipelines that could be affected, not just locations that are similar.
 - Resurvey ECDA region after immediate indications are repaired to determine if other indications were masked by large indication.
 - Include an investigative approach to identifying and excavate locations that could have third party damage defects.

Operators should document, in their IM program documentation, how more restrictive criteria were applied. This could consist of preparing two separate sets of requirements, one for use the first time ECDA is performed and a second for subsequent applications. Alternatively, operators could highlight or specify within their procedures the "more restrictive criteria" that must be applied on first application, or they may document them separately to share with inspectors during IM inspections.

Last Revision: 10/23/06

6.32 Can the 'ECDA' assessment option be applied to significant portions of above ground portions of pipelines that cannot be assessed with ILI tools or hydrostatic testing?

No. Per §195.588 (b) (1), the use of direct assessment on an onshore pipeline to evaluate the effects of external corrosion must follow the requirements of NACE Standard SP0502–2010. As stated in NACE SP0502-2010 Section 1.1.5 "ECDA as described in this standard is specifically intended to address buried onshore pipelines constructed from ferrous materials." While the NACE standard (Section 3.4.1.3) does, in certain cases, allow for the substitution of 100% direct examination at bell hole locations in lieu of a minimum of two indirect examination tools, PHMSA does not apply this exception to above ground piping. Operators may be able to technically justify a "direct" approach for assessing above ground lines, but such approaches are considered to be "other technology" that require a Notification to PHMSA per §195.452 (c) (1) (i) (D) and §195.452 (j) (5) (iv).

Last Revision: 8/31/16

ANOMALY REPAIR AND EXCAVATION

7.1 Do the anomaly repair schedule requirements in 195.452 (h) apply to ALL previous internal inspection runs performed by the operator, or just the integrity assessments required by 195.452 (i.e., the baseline assessment and subsequent integrity assessments)?

Yes. The repair and mitigation schedule requirements in §195.452 (h) apply to baseline assessments and subsequent re-assessments required by the integrity management rule. In addition, operators are expected to review the results of their prior integrity assessments to prioritize pipeline segments for the Baseline Assessment Plan [see §195.452 (e) (1) (i)], and to perform the information and risk analysis required in §195.452 (g) and (j).

In performing these reviews, operators should confirm that anomalies or defects identified in these earlier runs that might compromise integrity have been mitigated. See FAQ 7.13 for further information.

Last Revision: 12/16/05

7.2 How soon must the results of pipeline integrity assessment be evaluated?

Operators are expected to review the results of integrity assessments promptly. Operators are required to obtain sufficient information to identify conditions that present a potential threat to the integrity of the pipeline no more than 180 days after an integrity assessment, unless the operator can demonstrate that it is impracticable to obtain the information within this limit.

Last Revision: 1/17/02

7.3 What constitutes 'discovery of a condition'?

Discovery of a condition occurs when an operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. Depending on circumstances, an operator may have adequate information when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections, or when an operator receives the final internal inspection report. Operators are required to obtain sufficient information about a condition to make this determination no later than 180 days after an integrity assessment, unless the operator can demonstrate that the 180-day period is impractical.

Last Revision: 2/18/03

7.4 What is an 'immediate repair condition'?

An immediate repair condition is a detected anomaly involving:

- Metal loss greater than 80% of nominal wall regardless of dimensions.
- Predicted burst pressure less than the maximum operating pressure at the location of the anomaly. (Where burst pressure has been calculated from the remaining strength of the pipe using a suitable metal loss strength calculation, e.g., ASME/ANSI B31G).
- Dents on the top of the pipeline (above 4 and 8 o'clock position) with any indicated metal loss, cracking, or a stress riser.
- Dents on top of the pipeline with a depth greater than 6 percent of nominal pipe diameter.
- Significant anomaly that in the judgment of the person evaluating the assessment results requires immediate action.

Repairs must be made as soon as practicable. An operator must reduce pressure (to a level calculated using the methods referenced in section 451.6.2.2 (b) of ASME/ANSI B31.4 as applicable (see FAQ 7.15)) as soon as safety allows and operate at or below that pressure until a repair can be made.

Last Revision: 2/8/11

7.5 What is a '60-day condition'?

Anomalies not meeting criteria for "immediate repair condition" but involving:

- a dent on the top of the pipeline with a depth greater than 3 percent of the nominal pipeline diameter (greater than 0.25 inches for a pipeline diameter less than Nominal Pipe Size (NPS) 12).
- a dent located on the bottom of the pipeline that has indication of metal loss, cracking, or stress riser.

Last Revision: 1/17/02

7.6 What is a '180-day condition'?

Anomalies not meeting criteria for 'immediate repair condition' or '60-day condition' but which include any of:

- Dents with depth greater than 2 percent of the pipeline's diameter (0.25 inches for pipeline diameter less than NPS 12) that affect pipe curvature at a girth or longitudinal seam weld.
- Dents on top of the pipeline with a depth greater than 2 percent of the pipe diameter (0.25 inches for a pipeline diameter less than NPS 12).
- Dents on the bottom of the pipeline with a depth greater than 6 percent of the pipeline's diameter.
- Remaining strength of the pipe results in a safe operating pressure that is less than the current established MOP at the location of the anomaly using a suitable safe operating pressure calculation method (e.g., ASME/ANSI B31G).
- Areas of general corrosion with a predicted metal loss of >50% of nominal wall.
- Predicted metal loss of >50% of nominal wall that is located at crossings of another pipeline, or is in an area of widespread circumferential corrosion, or is in an area that could affect a girth weld.
- Potential crack indications that when excavated are determined to be cracks.
- Corrosion of or along a longitudinal seam weld.
- Gouges or grooves greater than 12.5% of nominal wall.

Last Revision: 1/17/02

7.7 Are there other anomalies that an operator is required to address?

Yes. All conditions identified by an integrity assessment or information analysis that could impair the integrity of the pipeline must be evaluated and scheduled for repair. Part 195 Appendix C contains guidance concerning other conditions that an operator should evaluate. (See also FAQ 3.3.)

Last Revision: 1/17/02

7.8 When must an operator complete its evaluation of anomalies identified by integrity assessments?

(Deleted. See FAQ 7.3.)

Last Revision: 5/10/12

7.9 Is permanently lowering the maximum operating pressure of a pipe segment an acceptable means of remediation?

(Deleted. See FAQ 7.15a.)

Last Revision: 5/10/12

7.10 What is the minimum deformation that constitutes a "dent"?

The repair provisions of the rule establish minimum sizes for dents requiring remediation. These are:

- Immediate repair conditions include dents of any depth, on the top of the pipeline, that have an indication of metal loss, cracking, or a stress riser. Dents on the top of the pipeline that are greater than 6 percent of pipe diameter in depth are also immediate repair conditions, regardless of other indications.
- Dents defined as 60-day conditions include dents of any depth, on the bottom of the pipeline, with indication of metal loss, cracking or a stress riser. Topside dents between 3 and 6 percent of pipe

diameter in depth are also 60-day conditions.

- Dents defined as 180-day conditions include those greater than 2 percent of pipe diameter in depth that affect pipe curvature at a girth weld or longitudinal seam, topside dents between 2 and 3 percent of pipe diameter in depth, and bottom-side dents greater than 6 percent of pipe diameter in depth.

Last Revision: 2/18/03

7.11 The proposed plan for responding to specific anomalies focuses principally on top-side dents. The apparent reason for this is that currently available in-line inspection technologies cannot reliably discriminate between plain dents and dents with mechanical damage. If an in-line inspection tool can reliably verify that a dent has no mechanical damage or metal loss, then will the regulations have a provision to eliminate the requirement for excavation?

(Deleted. See FAQ 7.10)

Last Revision: 5/10/12

7.12 A number of state and local jurisdictions have excavation permits that routinely require significant advance notice for special locations, such as wetlands. Some jurisdictions also require public comment periods. These situations may make it impossible for an operator to satisfy the repair schedules established in 195.452 (h) (4) for certain situations. Will OPS have a process in place to deal with such issues? Will OPS contact specific state or local agencies to support expediting the permitting and approval process?

(Deleted. See FAQ 12.1)

Last Revision: 5/10/12

7.13 If an operator elects to use an assessment conducted prior to 2002 as its baseline assessment [per 452 (d) (2)], how long does the operator have to review the results of the prior assessment and identify any anomalies that have not already been repaired or remediated that meet the criteria established in 452 (h)?

(Deleted. The time frame for using prior assessments as baseline assessments has passed.)

Last Revision: 5/10/12

7.14 If a segment that can affect an HCA is relatively short (e.g., only 2 miles in length), yet the operator internally inspects a longer portion around this segment (e.g., 50 miles from pig launcher to receiver), do the repair schedules in 195.452 (h) apply to the segment that can affect the HCA or the entire distance over which the pig is run?

The repair schedules in §195.452 (h) apply only to the segment that can affect the HCA. However, the operator is responsible for promptly addressing serious anomalies or defects identified in the other portions of the pigged section in accordance with §195.401 (b).

Last Revision: 2/18/03

7.15 The rule requires that an operator temporarily reduce pressure if an immediate repair condition is discovered (195.452(h)(4)(i)). With respect to this requirement:

a. Can the temporary reduction in operating pressure be based upon previous maximum operating pressures?

No. A reduction in operating pressure is intended to provide an additional safety margin until the defect can be remediated. To assure that additional margin is provided, the pressure reduction must be based upon pressures that the pipe has actually experienced, with the defect present (i.e., pressures for which safety has been demonstrated). These may be well below the “maximum operating pressure” for the pipe.

The rule requires that the pressure reduction must be calculated using the methods referenced in section 451.6.2.2 (b) of ANSI/ASME B31.4 if that method is applicable and the information needed is available. If that method cannot be used, the operator is responsible for determining an appropriate basis for assuring additional safety through a reduction in pressure. A reduction of 20 percent below the highest operating pressure actually experienced at the location of the defect within the two months preceding the inspection may provide the necessary additional safety margin.

b. Can the temporary reduction in operating pressure be based on calculations other than those defined in section 451.6.2.2 (b) of ASME/ANSI B31.4?

The methods referenced in section 451.6.2.2 (b) of ASME/ANSI B31.4 are required by the rule and must be used for all circumstances for which it is appropriate (e.g., corrosion). There are anomalies defined by the rule as immediate repair conditions for which the methods referenced in section 451.6.2.2 (b) are not applicable (e.g., dents). These are addressed in c. below. PHMSA Pipeline Safety is considering a change to the rule to recognize that section 451.6.2.2 (b) is not applicable to all immediate repair conditions and may also allow alternative methods for calculating the required reduction in pressure. Until the rule is changed, however, the specified method must be used in all instances in which it applies.

c. Is section 451.6.2.2 (b) of ASME/ANSI B31.4 applicable for calculating the temporary pressure reduction required for top-side dents with metal loss (195.452(h)(4)(i)(C)) and dents greater than 6% of the pipe diameter (195.452(h)(4)(i)(D))?

No. The methods referenced in Section 451.6.2.2 (b) of ASME/ANSI B31.4 are applicable to determining the remaining strength of pipe with corrosion defects or grind repairs (i.e., loss of wall thickness). Pressure must be reduced for other types of immediate repair conditions, but operators must develop appropriate engineering justification for the amount of pressure reduction. A reduction in operating pressure is intended to provide an additional safety margin until the defect can be remediated. To assure that additional margin is provided, the pressure reduction must be based upon pressures that the pipe has actually experienced, with the defect present (i.e., pressures for which safety has been demonstrated). These may be well below the “maximum operating pressure” for the pipe.

A reduction of 20 percent below the highest operating pressure actually experienced at the location of the defect within the two months preceding the inspection may provide the necessary additional safety margin.

Last Revision: 2/8/11

7.16 The rule defines “corrosion of or along a longitudinal seam” as a 180-day repair condition. Does the rule require all corrosion coincident with a longitudinal seam to be mitigated?

No. Isolated corrosion pits near a longitudinal pipe seam would not be expected to reduce pipe strength more than similar corrosion in the pipe body. A pattern of pitting near a longitudinal seam could be more significant. Grooving-type corrosion along a longitudinal seam would likely represent a significant challenge to pipe integrity.

The requirement of § 195.452(h)(4)(iii)(H) addresses corrosion “of or along” a longitudinal seam. Such conditions would indicate corrosive attack specifically affecting the longitudinal seam and which therefore could have a significant impact on pipe integrity.

A pipeline operator must consider the type of corrosion anomaly indicated as well as the age of their pipe and type of seam, and be able to demonstrate that detected corrosion does not affect the seam to any greater extent than the pipe body if corrosion near a longitudinal seam is not repaired under this criterion.

Last Revision: 9/12/25

7.17 What does "general corrosion" mean in the context of the 180-day repair criterion in 195.452(h)(4)(iii)(E)?

General corrosion is characterized by relatively uniform wall thinning over an area.

Last Revision: 10/12/02

7.18 How do the "burst pressure" that defines an immediate repair condition {452(h)(4)(i)(B)} and the "operating pressure" that defines a 180-day repair condition {452(h)(4)(iii)(D)} differ?

To determine if the repair provisions of §195.452 (h) (4) apply, an operator must determine the "burst pressure" and maximum safe operating pressure for locations where pipe wall degradation due to wall loss (e.g., corrosion) is identified.

Burst pressure is the minimum predicted failure pressure for the degraded pipe. In Modified B31G, the flow stress of the pipe is a material property related to its yield strength and is equal to the Specified Minimum Yield Strength (SMYS) of the pipe + 10,000 psi. Burst pressure of corroded pipe is determined by calculation, considering the flow stress and the dimensions of the metal loss (depth and length). For liquid pipelines, the maximum safe operating pressure of corroded pipe is equivalent to 72% of the pipe's calculated, predicted burst pressure. This equates to a safety factor of 1.39.

As noted, both burst pressure and maximum safe operating pressure are determined from calculations, given length and depth of pipe wall loss, using a suitable method (B31G and RSTRENG are referenced in the rule). If the new predicted burst pressure is determined to be less than the current established MOP, this indicates that the pipe could fail (burst) if it were operated at the current established MOP. This is an immediate repair condition as referred to in §195.452 (h) (4) (i).

If the new predicted burst pressure remains higher than the current established MOP, but the new maximum safe operating pressure is less than the current established MOP, a reduced safety margin is indicated. This condition requires remediation within 180 days as referred to in §195.452 (h) (4) (iii).

Last Revision: 7/9/02

7.19 Should tool tolerances be considered when determining if a detected anomaly meets repair criteria?

Yes. Operators are required to integrate relevant information on the condition of the pipeline in making decisions on excavation timing and other mitigative actions. Tool tolerances should be considered as part of the data integration process.

Information on tool tolerances should be used to assure that defects requiring early excavation and mitigative action are properly identified and characterized. This does not necessarily mean simply adding the vendor-supplied tolerance value to reported depth of indications. Several sources of data may be used, in conjunction with vendor-supplied tool tolerances, to characterize pipeline defects. These include results of previous excavations, confirmation digs, results of concurrent inspections, and comparison to prior inspections. Uncertainties in this data should also be considered.

In addition, information on tool tolerances may be incorporated in engineering analysis such as "probability of exceedance" to help operators prepare a comprehensive defect remediation plan and schedule future assessments. Pipeline operators have the flexibility to apply processes specific to their unique risks by utilizing these techniques when evaluating specific pipeline defects.

Tool tolerances are not the only uncertainty associated with assessment results and are therefore not the only factor to be considered in evaluating the quality of internal inspection data and in making excavation timing and mitigation decisions. Defect characterization should consider all relevant uncertainties to assure that defects posing a potential integrity threat, including those meeting the criteria in §195.452(h)(4), are promptly identified.

Last Revision: 2/18/03

7.20 Is a 20 percent reduction in pressure an adequate interim measure for immediate repair conditions?

No. A reduction of 20 percent below the highest operating pressure actually experienced at the location of the defect within the period immediately preceding the inspection (e.g., two months) may provide the necessary additional safety margin. Operators should evaluate each situation to determine if additional reduction, or line shutdown, is needed. Operators must use the methods referenced in Section 451.6.2.2 (b) of ASME/ANSI B31.4 to calculate the required pressure reduction for all situations in which it applies (as required by §195.452(h)(4)(i)).

See FAQs 7.15 and 7.22 for more information.

Last Revision: 8/31/16

7.21 Must anomalies identified during pig runs not considered "baseline" or "re-assessments" under the rule be repaired in accordance with the rule's repair criteria?

Yes. The integrity management rule requires a program that integrates all information regarding the integrity of the pipeline. Thus, all pig runs conducted after the effective date of the rule are considered activities covered by the rule. Anomalies discovered in segments that could affect high consequence areas after the effective date of the rule must be repaired in accordance with the criteria and schedules for repair conditions specified in §195.452(h). This includes anomalies identified by any pig run conducted after the effective date of the rule, even if the pig run is not considered a "baseline assessment" or "re-assessment".

Last Revision: 2/18/03

7.22 Section 195.452(h)(4)(i) requires that I temporarily reduce pressure in response to an immediate repair condition. The same paragraph also requires that I must calculate the reduction using the formula in section 451.6.2.2 (b) of ASME/ANSI B31.4. If using that formula results in a calculated safe pressure that is higher than my original operating pressure, must I still reduce pressure? To what?

Yes. A pressure reduction is required to provide additional safety margin until an immediate repair condition can be addressed. PHMSA Pipeline Safety expects that situations in which the calculated safe pressure using the methods referenced in Section 451.6.2.2 (b) of ASME/ANSI B31.4 is higher than the original operating pressure will be rare. Nevertheless, if the calculated pressure is greater than the existing operating pressure, pressure must still be reduced to provide the necessary margin.

Operators should determine the amount of such reduction based on their particular circumstances. Operators should also note that the specified formula only applies to metal loss anomalies (i.e., corrosion). It does not apply to immediate repair conditions that do not involve metal loss, nor does it apply to dents with metal loss. For those circumstances, operators must determine an acceptable method for calculating an acceptable reduced operating pressure. A reduction of 20 percent below the highest operating pressure actually experienced at the location of the defect within the two months preceding the inspection may provide the necessary additional safety margin.

Last Revision: 2/8/11

7.23 Must pipe for which the maximum operating pressure has previously been reduced (e.g., to preclude the need for pressure testing in accordance with 195.302(b)(1)) be repaired or retested to restore its original, higher maximum operating pressure?

Yes. Pipe that has been subjected to prior reductions in maximum operating pressure is not exempt from integrity management requirements. Such pipe must be included in an operator's integrity management plan. The integrity management rule does not, however, require that the maximum operating pressure for such pipe be increased. The MOP in effect at the time of scheduled integrity management assessments is the MOP for purposes of compliance with §195.452. It is not acceptable to lower MOP subsequent to an assessment in order to preclude identified anomalies from meeting remediation criteria in paragraph (h) of the rule. As required by the rule, any reduction in pressure taken to provide an immediate additional margin of safety may not last more than 365 days without the operator taking further remedial action to ensure the safety of the pipeline.

Last Revision: 2/28/02

IM PROGRAMS

8.1 What factors should drive Integrity Management Program changes?

An Integrity Management Program should change as appropriate to reflect operating experience, the conclusions drawn from integrity assessments made under the program, other maintenance and surveillance information, and evaluations of the consequences of a failure on the HCA.

Last Revision: 10/22/01

8.2 When must the Baseline Assessment Plan and Framework be completed?

(Deleted. The time frame for completion of the Baseline Assessment Plan and Framework has passed.)

Last Revision: 5/10/12

8.3 Will PHMSA Pipeline Safety prepare templates for Baseline Assessment Plans or Integrity Management Program Frameworks that operators can use?

(Deleted. The time frame for completion of the Baseline Assessment Plan and Framework has passed.)

Last Revision: 5/10/12

8.4 What is the difference between an acceptable Integrity Management Framework and a fully developed Integrity Management Program?

(Deleted. Operators are expected to now have fully mature Integrity Management Plans. See FAQ 8.5.)

Last Revision: 5/10/12

8.5 What is a framework?

A framework was to be an interim document describing how an operator then addressed each element of an integrity management program [§195.452 (f)], and their plans for how they intended to improve these processes to reach a fully developed integrity management program. Hence, the framework was a roadmap for developing a full integrity management program. PHMSA Pipeline Safety now expects that

all operators will have fully developed integrity management programs, considering the time that has passed since the rule became effective. A fully developed integrity management program would include complete, well-documented, and effectively implemented processes for all integrity management program elements defined in §195.452 (f) - e.g., data integration and integrity assessment results review, risk analysis, risk-based decision making, and performance evaluation.

Last Revision: 8/17/04

8.6 What is an Integrity Management Program?

An Integrity Management Program describes how the required elements will be implemented. Elements required to be part of the program (and the paragraphs of the rule in which they are described) are:

- a process for identifying which pipeline segments could affect a high consequence area (§195.452(f)(1));
- a baseline assessment plan meeting the requirements of paragraph (c) of the rule (§195.452(f)(2));
- an analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (§195.452(g) of the rule);
- criteria for repair actions to address integrity issues raised by the assessment methods and information analysis (§195.452(h));
- a continual process of assessment and evaluation to maintain the integrity of a pipeline (§195.452(j));
- identification of preventive and mitigative measures to protect the high consequence area (§195.452(i));
- methods to measure the effectiveness of the program (§195.452(k));
- a process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (§195.452(h)(2)).

A listing of the segments identified by the process described in the first bullet above must be part of the baseline assessment plan (second bullet) and is also considered part of the integrity management program.

A fully developed program involves complete documentation of how each element noted above will be performed. This documentation should include the designation of organizational roles and responsibilities for key IM activities.

Last Revision: 8/31/16

8.7 Will an operator be allowed to have one integrity management program that includes all of its regulated pipelines, in addition to those that can affect HCAs?

Yes. Most of the elements of an integrity management program (e.g., the risk analysis process and the review of integrity assessment results) can and should be applied to the entire pipeline system. However, in documenting the program results, those actions specific to segments that can affect HCAs and thus subject to the provisions of §195.452 (e.g., the integrity assessment results, pipeline repairs to address integrity issues, the leak detection system and EFRD evaluations, etc.), should be clearly discernable and readily available for PHMSA Pipeline Safety during inspections.

Last Revision: 1/3/02

8.8 Can operators include rural gathering systems in integrity management plans and programs? If so, will PHMSA Pipeline Safety inspect these portions of their plans and programs?

(Deleted. Refer to §195.11 and §195.12.)

Last Revision: 5/10/12

8.9 Does PHMSA Pipeline Safety expect operators to apply different relative risk ranking systems for lines in HCAs?

(Deleted. The deadline for performing baseline assessments has passed.)

Last Revision: 5/10/12

8.10 What integrity management program documentation should be available for PHMSA Pipeline Safety inspections and how long should that integrity management-related documentation be retained?

Part 195 Appendix C, paragraph VI provides an extensive listing of records that should be kept, and documentation that should be developed and maintained for an integrity management program. In addition to these items, each operator may have documentation that is unique to its integrity management program operation or program results. Records associated with integrity management program activities such as internal inspection results, pipe repair and mitigation records, risk analysis results, and records associated with the implementation of other preventive and mitigative actions such as EFRDs should be retained for the life of the pipeline system. The technical justification for changes to the Baseline Assessment Plans, the use of other technologies, and the extension for integrity assessment intervals beyond 5 years should also be retained for the life of the system. Documentation of integrity management program operational, analytical, and management processes should be kept up-to-date to reflect current practices and insights obtained from the integrity management program results.

Last Revision: 10/22/01

8.11 What kinds of information must be integrated in performing periodic evaluations and reassessment interval determinations?

Requirements for periodic evaluations and the determination of reassessment intervals require consideration of the rule-required information analysis. As outlined in §195.452 (g), an operator must consider all information relevant to determining risk associated with pipeline operation that could affect HCAs. This means information regarding the likelihood that a pipeline leak or failure will occur, as well as information regarding the consequences to an HCA. A list of some of the more important information that should be considered in an integrated manner is provided below.

- Results of previous integrity assessments
- Information related to determining the potential for, and preventing, damage due to excavation, including damage prevention activities, and development or planned development along the pipeline
- Corrosion control information (e.g., test station readings, close interval survey results)
- Information about the pipe design and construction (e.g., seam type, coating type and condition, wall thickness)
- Operating parameters (e.g., maximum operating pressure, pressure cycle history)
- Leak and incident history
- Information about how a failure could affect a high consequence area, such as the location of a water intake
- Advisory Bulletins, NTSB recommendations, etc.

Last Revision: 10/22/01

8.12 What kinds of information must be integrated in performing a continual evaluation of pipeline integrity?

(Deleted.)

Last Revision: 5/10/12

8.13 How is an operator to monitor the effectiveness of its integrity management program?

The rule requires that an operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas [§195.452(k)]. PHMSA Pipeline Safety expects that integrity management programs will evolve and improve as experience is gained, and measurement of whether the program is effective is important in guiding that evolution. Operators should periodically evaluate the effectiveness of their integrity management program. This evaluation process should include reviewing:

- The integrity assessment methods and practices being used. (e.g., are the in-line inspection tools delivering the quality of information expected?)
- The management and analytical processes. (e.g., is the risk assessment process failing to identify problem areas on the line?)
- Root cause analysis of failures and near-misses. Are these occurrences being critically examined and are the lessons learned being implemented?
- Performance measures. Are objective measures of program results showing that improvement is needed?

Part 195 Appendix C includes guidance on methods that can be used to evaluate a program's effectiveness.

Last Revision: 10/22/01

8.14 Will operators be expected to consider external conditions such as earthquake fault lines or mining subsidence in their integrity management program? Will these be classified as HCAs or require special repair provisions?

As part of the information and risk analysis required by §195.452 (f) (3) and §195.452 (i), an operator is expected to consider all information that can affect the likelihood and consequences of pipeline failure.

§195.452 (e) (1) specifically identifies geological hazards and subsidence as risk factors to consider in prioritizing segments for integrity assessment scheduling. Thus, if such external risk factors are present, they must be considered by the operator.

These external conditions are not HCAs. HCAs are specifically defined in §195.450 to include high population areas, other populated areas, commercially navigable waterways, and unusually sensitive areas. It is possible that geological hazards may be present in HCAs, but a region near the line that contains geological hazards is not (by itself) an HCA.

The repair provisions of §195.452(h) apply only to line segments that could affect HCAs – not segments in geological hazard areas outside of HCAs. However, the presence of geological hazards or other external factors near line segments that can affect HCAs should be considered when establishing the schedule for anomaly mitigation and repair required by §195.452(h)(3).

Last Revision: 2/18/03

8.15 The Integrity Management Program portion of the rule [195.452 (f)] applies to all portions of a pipeline system that can impact HCAs, including pump stations, terminals, and other

equipment. What must an operator do to comply with the rule for these facilities?

While the integrity assessment provisions of the rule apply only to the line pipe, the other provisions of the rule apply to pump stations, terminals, and other equipment if a failure at these locations could impact a high consequence area. Thus, operators should include in their integrity management program processes for addressing these facilities. These processes should:

- identify if failures at these facilities could impact HCAs,
- integrate all available information affecting the likelihood and the consequences of equipment or facility failure, and
- identify and implement additional preventive or mitigative measures to reduce risk at these facilities, if needed.

An operator's performance monitoring process should evaluate the effectiveness of these processes and the risk controls that are implemented to reduce facility risk.

Last Revision: 10/22/01

8.16 The rule requires that the review of integrity assessment results and information analysis (i.e., risk analysis) be performed by a person qualified to evaluate the results and information. Are these covered tasks under Operator Qualification requirements? If not, how are operators expected to demonstrate that they have satisfied this requirement?

The integrity assessment results review and risk analysis are not "covered tasks" under Subpart G of Part 195. During PHMSA Pipeline Safety inspections, operators should be prepared to describe the relevant experience, training, and other qualifications of the personnel performing this work. As part of their Integrity Management Program, they should also describe their provisions for assuring that individuals performing this work have the necessary technical expertise and experience.

Last Revision: 8/17/04

8.17 Can pipeline integrity management programs required by 195.452 be part of broader corporate safety or integrity management systems (e.g., as described in API Publication 9100A, Model Environmental, Health and Safety (EHS) Management System)?

Yes. Pipeline integrity management programs must meet the requirements of §195.452. As long as those requirements are met, the programs may be part of broader company management systems. Elements of existing management systems that can meet the requirements of the rule can be incorporated into the pipeline integrity management program. Alternatively, operators may decide that processes and methods used in their pipeline integrity management programs could be useful for other purposes and may integrate them into broader company systems. PHMSA Pipeline Safety expects to see a description of the pipeline integrity management program that meets the requirements of the rule. PHMSA Pipeline Safety is willing to consider elements of broader company programs and systems as part of this program description, provided they are sufficiently complete and robust to meet rule requirements. It is the operator's responsibility to demonstrate how such existing corporate management systems meet the requirements of the rule.

Last Revision: 2/18/03

8.18 Can operators include potential business consequences (e.g., curtailments, plant shutdown) in its risk determinations?

Yes. The focus of the integrity management rule is reducing the risk of pipeline failures to high consequence areas. The integrity management programs developed to comply with rule requirements should include the use of risk analysis to support operator integrity decisions. Operator risk analysis processes require the evaluation and measurement of both the probability and consequences of pipeline

failures. The appropriate consequences to be included in these risk analyses depend on the decisions that are being supported by the risk analysis results.

In the context of fulfilling requirements of the integrity management rule, operators should maintain a focus on the risk of failures to high consequence areas. Consequently, operators should emphasize those consequences that are considered in the definition of high consequence areas (i.e., human health and safety, environmental protection, property damage, local economic impacts).

If consequences considered in the risk analysis are expanded to include consequences related to operator business performance, then the operator must provide assurance that this approach does not skew decisions away from protection of HCAs. For example, consideration of operator business performance consequences should not result in pipeline segments with high risk to HCAs being given lower priority for integrity assessments than segments with low risks to HCAs but higher business consequences.

There may be situations in which business impacts have secondary related safety consequences. Operators may include these consequences in the overall assessment of risk related to an integrity decision. It is necessary, however, that such secondary consequences are evaluated and balanced appropriately with other safety and environmental consequences in the risk analysis.

Last Revision: 10/12/02

8.19 What type of risk analysis process would PHMSA Pipeline Safety prefer, quantitative or qualitative?

Risk analysis plays a critical role in several integrity management program elements. These include ranking segments that can affect HCAs for assessment, determining appropriate re-assessment intervals, and evaluating the need for preventive and mitigative actions. Operators are responsible for applying a risk evaluation methodology that suits their circumstances and can fulfill these needs. They can be either quantitative or qualitative. PHMSA Pipeline Safety will consider how the operator assesses risk, including its thoroughness and completeness in applying whatever approach is used.

Last Revision: 10/12/02

LEAK DETECTION, EFRD, AND ADDITIONAL RISK CONTROLS

9.1 What is an emergency flow restricting device (EFRD)?

An EFRD is a device that can limit the amount of product released as a result of a leak or rupture. An EFRD is defined by the rule as either a check valve or a remote control valve.

Last Revision: 2/18/03

9.2 What criteria must an operator use in determining whether emergency flow restricting devices are required to protect HCAs?

Operators must make these determinations using criteria that they define, considering the circumstances of each HCA and the pipeline segments that may affect it. The rule includes specified factors that must be considered in these evaluations. They include:

- the swiftness of leak detection and pipeline shutdown capabilities,
- the type of commodity carried,
- the rate of potential leakage,
- the volume that can be released,
- topography or pipeline profile,
- the potential for ignition,

- proximity to power sources,
- location of nearest response personnel,
- specific terrain between the pipeline and the high consequence area, and
- benefits expected by reducing the spill size.

An operator is required to install an emergency flow restricting device if the operator determines one is needed to protect an HCA. PHMSA Pipeline Safety will be reviewing operator analyses for technical justification and thoroughness. Because of the significant variation in pipeline design and operation, the physical characteristics of the land and waterways near pipelines, and the different nature and location of HCAs, PHMSA Pipeline Safety believes specific EFRD installation criteria are neither desirable nor appropriate.

Last Revision: 2/18/03

9.3 What criteria will OPS use to determine whether an operator's evaluation of the need for EFRDs is satisfactory?

(Deleted. Response repetitious of code language.)

Last Revision: 5/10/12

9.4 What criteria must an operator consider in determining whether enhancements to leak detection are required?

Operators are required to have a means of detecting leakage on their pipelines. Operators must evaluate that capability and improve it, if necessary, to protect the high consequence area. The evaluation must include at least the following factors:

- length and size of the pipeline
- type of product carried
- the pipeline's proximity to the high consequence area
- the swiftness of leak detection
- location of nearest response personnel
- leak history, and
- risk assessment results.

In addition, PHMSA Pipeline Safety believes the operator should consider:

- system operating characteristics (e.g., steady state operation, high transient pressure and flow),
- current leak detection method for the HCA areas,
- use of SCADA,
- thresholds for leak detection,
- flow and pressure measurement,
- specific procedures for lines that are idle but still under pressure,
- specific consequences related to sole source water supplies regarding additional leak detection means,
- testing of leak detection means, such as physical removal of product from the pipeline to test the detection, and
- any other characteristics that are part of the system leak detection.

Last Revision: 10/22/01

9.5 What is the minimum acceptable leak detection system in order to comply with 195.452 (i) (3), which states "an operator must have a means to detect leaks on its pipeline system."?

PHMSA Pipeline Safety will address leak detection capability with each operator according to the requirements of the regulation. This includes a "means to detect leaks" and an evaluation of the capability of the leak detection means. The rule specifies several factors that the evaluation must consider. These, and additional factors that PHMSA Pipeline Safety believes the operator should consider are outlined in FAQ 9.4.

PHMSA Pipeline Safety will evaluate the operator's process for considering these factors and making decisions about the adequacy of leak detection during integrity management inspections.

Last Revision: 12/16/05

9.6 49 CFR 195.134 and 195.444 require that computational pipeline monitoring (CPM) leak-detection systems on hazardous liquid pipelines must comply with API Standard 1130 for design and operations/maintenance respectively. Paragraph (i) (3) of the integrity management rule requires that operators must have a means to detect leaks on pipelines that can affect HCAs. Must leak detection means used to satisfy 49 CFR 195.452 (i) (3) meet API-1130?

There are many ways that an operator may detect leaks. The operator must conduct a risk analysis, per §195.452 (i) (2) to identify the need for additional preventive and mitigative features. Leak detection capability must be evaluated, per §195.452 (i) (3), using the results of this risk analysis and other factors listed in that paragraph. An operator must determine if modifications to its leak detection means are needed to improve the operator's ability to respond to a pipeline failure and protect HCAs. An operator may determine, on an individual pipeline segment basis, that a CPM system is needed to meet this need. If a CPM system is employed, its implementation and operation must satisfy the requirements of §195.134 and §195.444, which reference certain aspects of API-1130.

Last Revision: 10/23/01

9.7 What preventive and mitigative actions must be taken to protect HCAs?

Operators must conduct risk analyses for the line segments that could affect HCAs. These analyses should identify and evaluate the need for additional preventive and mitigative actions to protect HCAs. The rule does not specify which actions must be taken. A list of some measures which might be taken includes:

- implementing damage prevention best practices,
- enhanced cathodic protection monitoring,
- reduced inspection intervals,
- enhanced training,
- installing EFRDs,
- modifying the systems that monitor pressure and detect leaks,
- conducting drills with local emergency responders, and
- other management controls.

An operator must implement the appropriate preventive and mitigative actions to address the risks unique to each specific line segment or facility.

Last Revision: 10/22/01

9.8 What factors must be considered in risk analyses conducted to determine if additional preventive or mitigative actions are needed?

An operator must consider all risk factors relevant to a particular pipeline line segment or facility. This includes risk factors that influence both the likelihood and the consequences of pipeline failure. This would include:

- design and construction information;
- maintenance and surveillance activities;
- operating parameters and operating history;
- right-of-way information, information about the population and the environment near the pipeline, etc.

The rule specifically identifies several risk factors that should be considered including:

- terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;
- elevation profile;
- characteristics of the product transported;
- amount of product that could be released;
- possibility of a spillage in a farm field following the drain tile into a waterway;
- ditches alongside a roadway the pipeline crosses;
- physical support of the pipeline segment such as by a cable suspension bridge;
- exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

Last Revision: 2/18/03

9.9 How long after completing the baseline assessment for a segment does an operator have to conduct a risk analysis and determine whether additional preventive or mitigative actions are needed (including the need for EFRDs and leak detection system enhancements)? If an operator determines that additional actions are warranted, how long does it have to implement them?

An operator should not wait until after an assessment is conducted to perform its risk analysis. For some segments, the baseline assessment may not be conducted for several years. Operators can, and should, gather enough information before this time to evaluate risk and make the required determinations regarding preventive and mitigative measures.

After an operator completes its baseline assessment for a segment, it should re-visit its risk analysis, incorporating the results of the assessment and identifying the most significant risks that remain. The operator should then analyze those significant risks to determine if additional actions (other or additional Preventive & Mitigative Measures) should be undertaken. Although the rule establishes no firm time limits by when this risk analysis must be performed, PHMSA Pipeline Safety believes it is reasonable to expect that this analysis as well as the identification of any additional potential preventive and mitigative actions should be completed within one year after the assessment has been performed. This will allow time for reviewing the assessment results and excavating the worst features, thereby developing confidence in the validity of the assessment and an understanding of the line's condition.

PHMSA Pipeline Safety recognizes that the time required to implement preventive and mitigative actions is highly dependent on the proposed risk control activity. Some actions may be simple "quick fix" activities that can readily be implemented in the field. Other actions may involve major capital expenditures and require significant time for budgeting, engineering and design, and implementation. Because of this wide disparity, there is no fixed time requirement for implementing preventive and mitigative actions. PHMSA Pipeline Safety expects operators to provide a schedule by when additional preventive and mitigative measures will be taken, and to act as quickly as practical after identifying the need for such risk controls. In situations where lengthy periods are required for implementation, operators should determine if there are relatively simple, interim measures that can be taken to reduce risk while major projects are being implemented.

Last Revision: 7/15/05

9.10 How do operators assess and control risk caused by third-parties over which they have

no direct control?

As part of a comprehensive risk analysis required by §195.452(f) and §195.452(i), PHMSA Pipeline Safety expects operators to determine the risk associated with third party damage to pipeline facilities that could affect an HCA. PHMSA Pipeline Safety will not prescribe specific risk analysis methods that the operator must use; there are a number of acceptable approaches. PHMSA Pipeline Safety also understands that outside force damage prevention is challenging because it involves factors outside of the operator's control. Nonetheless, there are a number of actions operators can take to reduce the likelihood of third party damage. If a pipeline facility can affect an HCA, and third-party damage is determined to be a significant risk (e.g., as might be expected in a high population area, with new construction near the line), §195.452 (i) (1) requires the operator to take measures that reduce the likelihood of third party damage.

Last Revision: 10/22/01

9.11 Leak detection is applied to an entire system, which generally contains both HCA and non- HCA segments. Therefore, how do you compare leak detection between the HCA and non-HCA segments?

The rule requires that operators have leak detection on their pipeline systems. This detection provides protection against leaks in segments that can affect HCAs and in those that cannot. The rule also requires, however, that operators evaluate the capability of their leak detection means and modify, as necessary, to protect high consequence areas. This does not imply that new/improved leak detection capability must be installed only in segments that can affect HCAs, but rather operators assure that whatever leak detection is provided for the system is adequate to provide the level of protection appropriate for HCAs that the system can affect.

Last Revision: 2/18/03

9.12 Can I take credit for existing automatic valves in my analysis considering the need for Emergency Flow Restriction Devices (EFRD)?

Yes. Operators should consider all existing design features that would limit the amount of release in the event of a failure in evaluating whether addition of EFRDs is necessary.

Last Revision: 9/21/04

9.13 Can the evaluation of additional preventive and mitigative (P&M) measures be excluded for portions of HCA-affecting lines determined to be sufficiently "low" in risk by an operator's risk analysis process?

No. §195.452 (i) (1) requires that *"An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection."* Therefore, regardless of the perceived level of risk, additional P&M measures must be identified and evaluated. This is particularly important when qualitative-oriented risk analysis approaches are utilized that classify risk levels on a relative basis. Risk that is judged to be "low" relative to other pipeline sections does not necessarily imply that risk cannot be reasonably lowered via additional or enhanced P&M measures.

The rule, however, does not require that all identified measures be implemented. Once potential P&M measures are identified, operators must exercise technical judgments in determining which to implement, and when. PHMSA recognizes that not all possible actions can be taken and that all actions taken may not be able to be completed immediately. PHMSA does not prescribe a specific set of criteria for P&M measure implementation but expects that operators establish an adequate, documented basis for deciding which candidate measures are implemented and when based upon operational conditions.

Last Revision: 8/22/07

INSPECTION AND ENFORCEMENT

10.1 How will OPS inspect operators for compliance with the new Integrity Management rule?

(Deleted. All Hazardous Liquid pipeline operators have been inspected.)

Last Revision: 5/10/12

10.2 When will these initial integrity management inspections be performed?

(Deleted. All Hazardous Liquid pipeline operators have been inspected.)

Last Revision: 5/10/12

10.3 What is the expected duration of the segment identification and completeness check inspections?

(Deleted. Segment identification inspections have been completed.)

Last Revision: 5/10/12

10.4 What did the segment identification and completeness check inspection cover?

(Deleted. Segment identification inspections have been completed.)

Last Revision: 5/10/12

10.5 Will Integrity Management Program inspections be scheduled in advance?

(Deleted. All Hazardous Liquid pipeline operators have been inspected.)

Last Revision: 5/10/12

10.6 How can operators know what inspections will cover?

Inspections of integrity management requirements are being conducted using the Integrity Management inspection form. These inspection forms are available on the PHMSA public website (<http://www.phmsa.dot.gov/pipeline/library/forms>).

Last Revision: 8/31/16

10.7 During Segment Identification and Completeness Check inspections, did OPS provide feedback to the operator on intended plans for “other assessment methods,” even if the operator has not yet given OPS a 90-day notification?

(Deleted. Segment identification inspections have been completed.)

Last Revision: 5/10/12

10.8 When does OPS expect to complete the Comprehensive Baseline Assessment Plan and

Integrity Management Program Framework inspections?

(Deleted. The first round on Integrity Management inspections has been completed.)

Last Revision: 5/10/12

10.9 What are the state Pipeline Safety agency roles in the integrity management inspection process?

(Deleted. See FAQ 11.2.)

Last Revision: 5/10/12

10.10 Will integrity management inspection results on a company be publicly available?

No. PHMSA Pipeline Safety does not intend to make the detailed results of individual company inspections available to the public. However, consistent with the provisions of the Freedom of Information Act, members of the public may request and be granted access to information from PHMSA Pipeline Safety files.

Last Revision: 12/16/05

10.11 How will “noteworthy practices” be identified during inspections and communicated to other operators?

(Deleted. PHMSA holds workshops to communicate noteworthy practices.)

Last Revision: 5/10/12

10.12 Will integrity management inspection results on a company be publicly available?

(Deleted. Integrity Management inspections of Hazardous Liquid pipeline operators have been completed. Agency records are publicly available in accordance with the Freedom of Information Act (FOIA), 5 U.S.C. § 552.)

Last Revision: 5/10/12

10.13 How will PHMSA Pipeline Safety provide training and oversight to state inspectors conducting reviews and audits of operator integrity management plans?

PHMSA Pipeline Safety has conducted training for state inspection personnel who are expected to participate in integrity management inspections. This training was based on the Integrity Management inspection form and is the same as that provided to PHMSA Pipeline Safety inspectors. State personnel are also observing PHMSA Pipeline Safety conduct of inspections for interstate pipelines.

PHMSA Pipeline Safety will monitor state activities in this area and will conduct additional training or provide additional guidance as necessary.

Last Revision: 12/5/02

10.14 Can an operator be cited for not complying with Appendix C?

The enforceability of Part 195 Appendix C is addressed in the preamble to the final rule, as follows: “An Appendix is guidance that is intended to give advice to operators on how to implement the requirements

of the integrity management rule. An appendix does not have the same force as the regulation itself. An operator does not have to follow the guidance. However, if an operator incorporates parts of the Appendix into its integrity management program, an operator must then comply with those provisions.”

The guidance in Part 195 Appendix C was also utilized in developing PHMSA Pipeline Safety’s Integrity Management inspection form and will be consulted, as appropriate, during the inspection process.

Last Revision: 10/22/01

10.15 How will PHMSA Pipeline Safety ensure consistency in enforcing integrity management requirements?

The integrity management rule contains a number of management-based and performance-based requirements. Determining enforcement action for these types of requirements is fundamentally different than for prescriptive requirements. Enforcement decisions in this area require subjective judgments on the part of inspectors and PHMSA Pipeline Safety managers. PHMSA Pipeline Safety recognizes that ensuring consistency in the enforcement process is very important. To address this task, PHMSA Pipeline Safety has undertaken steps to improve the fairness and consistency in its enforcement process. For example, integrity management inspections are conducted using a written Integrity Management inspection form that helps guide inspectors toward making consistent judgments. PHMSA Pipeline Safety has conducted reset meetings with inspection teams to review inspection findings and to discuss ranges of appropriate enforcement actions to ensure that appropriate levels of consistency are being achieved. Additionally, PHMSA Pipeline Safety is developing specific guidance to assist lead inspectors and PHMSA Pipeline Safety management in identifying appropriate enforcement actions for a wide range of integrity management issues.

Last Revision: 12/16/05

10.16 How do you determine if an operator’s management is taking the IMP requirements seriously, as opposed to the lower ranks? What do you look for to demonstrate the right attitude?

Strong and visible support of senior pipeline operator management is important to the success of the integrity management program required by §195.452. Although there are no simple indicators to demonstrate management support, PHMSA Pipeline Safety will attempt to gauge the level of management commitment during inspections by assessing such things as whether an adequate level of resources are applied to integrity management, whether schedules and plans are met, and how problems and unexpected situations that may arise are dealt with. PHMSA Pipeline Safety expects that responsible managers will have an understanding of major elements of the IM program and will be aware of any significant integrity issues. PHMSA Pipeline Safety will look for evidence of this knowledge during its review of program documentation and discussions with key personnel. Indications of possible inadequate support and involvement by management may be used by PHMSA Pipeline Safety as indicators to adjust its plans for overseeing operator integrity management programs, since problems can be expected to occur more frequently in programs with inadequate management support.

Last Revision: 10/12/02

STATE ROLES, INTRA-STATE LINES

11.1 Some States have adopted, or are considering, integrity management rules including requirements similar to those in the federal rule. If a company operates both intra- and interstate pipelines in such a State, which integrity management rules apply to each type of pipeline?

A state certified to inspect an intrastate pipeline is required to have safety standards that are at least as stringent as the federal Pipeline Safety rules. If a State rule is less stringent, or has not been adopted as

State law, the federal rule would apply to both intrastate and interstate pipelines.

Once a State has adopted integrity management program standards, then those standards, including any provisions that may be more restrictive than the federal rule, would be enforced by the State for intrastate pipelines.

Questions about applicability and enforcement of rules in specific States should be directed to the appropriate State agency.

Last Revision: 11/5/01

11.2 What are the state Pipeline Safety agency roles in the integrity management inspection process?

States with hazardous liquid programs will conduct integrity management inspections of intrastate pipelines within their state and may participate in interstate inspections of those operators with facilities in their state. PHMSA Pipeline Safety works with hazardous liquid state Pipeline Safety programs in conducting integrity management inspections. PHMSA Pipeline Safety has provided training in the integrity management rule, the inspection Integrity Management inspection form, and the inspection process for states with hazardous liquid programs. Integrity management training courses have been developed and offered to provide integrity management training to new state inspectors.

Prior to integrity management inspections, PHMSA Pipeline Safety solicits information about local issues or state program integrity concerns associated with the pipeline being inspected. In those instances where operators provide integrity program information prior to an inspection, that information is shared with the state programs in the states in which the operator has assets.

Where possible, states participate along with PHMSA Pipeline Safety in the inspection of interstate operators. States may also assist in follow-up inspections to address specific issues within their state. Following the inspection, PHMSA Pipeline Safety shares with and seeks state program comment on draft summary reports and inspection-related documentation.

Last Revision: 2/18/03

11.3 Does OPS consider current Texas state rules adequate or will Texas have to adopt the new Federal rule?

(Deleted. See FAQ 11.5.)

Last Revision: 5/10/12

11.4 The Federal Rule identifies certain situations where an operator is required to notify OPS:

- 1. if they intend to use an assessment interval greater than 5 years;**
- 2. if they desire to use a technology other than in-line inspection or pressure testing to conduct integrity assessments, or**
- 3. if the repair provisions in 195.452 (h) (3) cannot be met and the operator cannot provide safety through a reduction in operating pressure.**

For intra- and interstate pipelines operating in States with their own integrity management rules, should these notifications be sent to OPS, to the State, or both?

(Deleted. See FAQ 12.1.)

Last Revision: 5/10/12

11.5 For those requirements of State integrity management regulation that are less stringent than the Federal rule (e.g., time interval between periodic assessments), will PHMSA Pipeline Safety require the state to adopt or revise its rule to incorporate the Federal requirements?

Yes. State requirements must be at least as stringent as corresponding federal requirements. For example, the Railroad Commission of Texas will assure that the requirements of the federal rule are being met, as a minimum, during its review of operator assessment plans (as required by the Texas rule). This will include assuring that 5-year re-assessment intervals are used for unusually sensitive areas in rural locations that would otherwise be subject to a 10-year requirement under the Texas rule. The Texas rule applies to more than high consequence areas.

Last Revision: 11/5/01

11.6 The Texas rule requires that written plan by February 1, 2002 - two months before the earliest deadline for Baseline Assessment Plan and Integrity Management Framework preparation are required by 195.452. Does the Texas operator have to meet an earlier date if operating in multiple states but trying to develop a single program?

(Deleted. The deadline for submitting written plans in Texas has passed.)

Last Revision: 5/10/12

11.7 If an operator develops a single Baseline Assessment Plan that covers both intra- and interstate pipelines, does the need to complete assessments on 50% of the pipeline mileage that can affect HCAs apply to both intra- and interstate line segments, or just interstate line segment mileage?

(Deleted. The time frame for completing assessments on 50% of pipeline mileage has passed.)

Last Revision: 5/10/12

11.8 If a state establishes a definition that expands upon the HCAs defined in 195.450, do the requirements of 195.452 apply to line segments that affect these additional state-defined HCAs?

For both intra- and interstate pipelines, the requirements of §195.452, as a minimum, apply to HCAs as defined in §195.450. States may apply more restrictive requirements, including a broader definition of HCAs to intrastate lines, but those requirements do not affect interstate pipelines. (It should be noted that the Texas rule does not define HCAs. The Texas rule applies to all pipe.)

Last Revision: 11/5/01

NOTIFICATIONS

12.1 What types of notifications are required by the rule?

The notifications required by the rule are:

Circumstance/type	Deadline for Submittal	Information Required
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Inability to meet remediation deadlines in the rule and unable to reduce pressure	When operator determines schedules cannot be met	Description of defects/repairs needed, reason for delay, why pressure can't be reduced, basis for concluding delay won't jeopardize health or environment, schedule for repair, other mitigative actions planned
Pressure reduction will exceed 365 days	When pressure reduction exceeds 365 days	Reasons for the delay, description of additional remedial actions
Use of technology other than in-line inspection, pressure testing, or external corrosion direct assessment for conducting assessments	90 days prior to assessment (Separate notification is required for each assessment, even if the other technology has been used in a prior assessment.)	Description of "other technology", basis for concluding equivalent understanding of pipe condition, schedule for assessment
Variance from 5-year re-assessment interval (unavailable technology)	180 days before end of 5-year interval	Date and method of last assessment, reason why required interval cannot be met, interim evaluation of pipe integrity, schedule for assessment
Variance from 5-year re-assessment interval (engineering basis)	270 days before end of 5-year interval	Date and method of last assessment, proposed new retest interval, actions that will provide equivalent understanding of pipe condition, summary of engineering basis

All notifications must include information about the pipe segments and HCAs involved as well as operator contact information.

Last Revision: 7/2/15

12.2 Under what circumstances must an operator submit a notification?

(Deleted. See FAQ 12.1.)

Last Revision: 5/10/12

12.3 When must notifications be submitted?

(Deleted. See FAQ 12.1.)

Last Revision: 5/10/12

12.4 What information must be in a notification?

(Deleted. See FAQ 12.1.)

Last Revision: 12/6/02

12.5 How can notifications be submitted?

Operators submit notifications:

By e-mail to: InformationResourcesManager@dot.gov

or

By mail:

ATTN: Information Resources Manager
DOT/PHMSA/OPS
East Building, 2nd Floor (PHP-20), E22-321
1200 New Jersey Ave., SE
Washington, DC 20590

Last Revision: 5/25/12

12.6 Will PHMSA Pipeline Safety review operator notifications and formally respond to the operator? Will PHMSA Pipeline Safety communicate responses to specific company notifications to the broader industry?

Operator notifications inform PHMSA Pipeline Safety of changed circumstances in the operator's integrity management program, which may indicate a need for an unscheduled inspection. PHMSA Pipeline Safety reviews all notifications received from operators, to determine if such inspections are needed. Notifications concerning intrastate pipeline segments in states with certified hazardous liquid pipeline programs are reviewed by state Pipeline Safety officials. PHMSA Pipeline Safety will formally respond to each notification through e-mail.

A summary of each notification is available from this web site (<https://www.phmsa.dot.gov/data-and-statistics/pipeline/leading-indicators-srcr-and-im-notifications>), along with the status of the review. This allows the public to see where operators are deviating from the rule, and also allows operators to see notifications from other operators. PHMSA Pipeline Safety responds any time it determines that it objects to the actions proposed in a notification, describing the basis for its conclusion and additional actions it expects operators to take.

Operators subject to specific State rules and regulations that require notification must also comply with those requirements.

Last Revision: 5/25/12

12.7 How will an operator know if PHMSA Pipeline Safety objects to its notification?

PHMSA Pipeline Safety responds to any operator notification with an indication that it does or does not have an objection to the operator's planned action.

In the case where there is an objection, PHMSA Pipeline Safety will contact the operator to determine whether the objection can be resolved or if an unscheduled inspection is appropriate.

Last Revision: 5/25/12

12.8 How will an operator know if PHMSA Pipeline Safety has no objections to its notification?

(Deleted. See FAQ 12.1.)

Last Revision: 5/10/12

12.9 Do I need a password to view operator notifications?

No. Anyone can view summaries of all notifications that have been submitted by operators, and the status of PHMSA Pipeline Safety review of each notification, from this web site (<https://www.phmsa.dot.gov/data-and-statistics/pipeline/leading-indicators-srcr-and-im-notifications>).

Last Revision: 5/25/12

12.10 Are there notification requirements applicable to the use of 'other technology'?

(Deleted. See FAQ 12.1.)

Last Revision: 5/10/12

12.11 What must be included in notices informing PHMSA Pipeline Safety of inspection intervals that will be scheduled to extend beyond 5 years? When must they be submitted?

(Deleted. See FAQ 12.1.)

Last Revision: 5/10/12

12.12 With 'online' notification submission, is there a confirmation that the submitted notification was actually received?

(Deleted. See FAQ 12.1.)

Last Revision: 10/12/02

12.13 Are Safety-Related Condition Reports required to be filed when an operator implements a pressure reduction for an immediate repair per §195.452(h)(4)(i)?

The requirements for safety-related condition reports are distinct from those for integrity management. Where the provisions of §195.55 require a report, such report must be made independent of any requirements in the integrity management rule.

Last Revision: 10/15/09

NATIONAL PIPELINE MAPPING SYSTEM

(All questions pertaining to NPMS should be referred to the NPMS FAQs @ <https://www.npms.phmsa.dot.gov/>.)

All previous questions in this section have been deleted.

Last Revision: 5/10/12