Gas Transmission Integrity Management Enforcement Guidance
Sections 192.901 through 192.951

Introduction

The materials contained in this document consist of guidance, techniques, procedures and other information for internal use by the PHMSA pipeline safety enforcement staff. This guidance document describes the practices used by PHMSA pipeline safety investigators and other enforcement personnel in undertaking their compliance, inspection, and enforcement activities. This document is U.S. Government property and is to be used in conjunction with official duties.

The Federal pipeline safety regulations (49 CFR Parts 190-199) discussed in this guidance document contains legally binding requirements. This document is not a regulation and creates no new legal obligations. The regulation is controlling. The materials in this document are explanatory in nature and reflect PHMSA's current application of the regulations in effect at the time of the issuance of the guidance. In preparing an enforcement action alleging a probable violation, an allegation must always be based on the failure to take a required action (or taking a prohibited action) that is set forth directly in the language of the regulation. An allegation should never be drafted in a manner that says the operator "violated the guidance."

Nothing in this guidance document is intended to diminish or otherwise affect the authority of PHMSA to carry out its statutory, regulatory or other official functions or to commit PHMSA to taking any action that is subject to its discretion. Nothing in this document is intended to and does not create any legal or equitable right or benefit, substantive or procedural, enforceable at law by any person or organization against PHMSA, its personnel, State agencies or officers carrying out programs authorized under Federal law.

Decisions about specific investigations and enforcement cases are made according to the specific facts and circumstances at hand. Investigations and compliance determinations often require careful legal and technical analysis of complicated issues. Although this guidance document serves as a reference for the staff responsible for investigations and enforcement, no set of procedures or policies can replace the need for active and ongoing consultation with supervisors, colleagues, and the Office of Chief Counsel in enforcement matters.

Comments and suggestions for future changes and additions to this guidance document are invited and should be forwarded to your supervisor.

The materials in this guidance document may be modified or revoked without prior notice by PHMSA management.

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Glossary

For a complete "Glossary of Terms" please refer to the following link:

http://www.phmsa.dot.gov/staticfiles/PHMSA/Pipeline/TQGlossary/Glossary.html

Enforcement Guidance	Part 192, Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.901
Section Title	What do the regulations in this subpart cover?
Existing Code Language	This subpart prescribes minimum requirements for an integrity management program on any gas transmission pipeline covered under this part. For gas transmission pipelines constructed of plastic, only the requirements in §§192.917, 192.921, 192.935 and 192.937 apply.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95A, 69 FR 9307, December 20, 2003
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB -12-03** **Notice to Operators of Driscopipe 8000 High Density Polyethylene Pipe of the Potential for Material Degradation** On March 6, 2012, PHMSA issued this advisory bulletin to alert operators using Driscopipe® 8000 High Density Polyethylene Pipe (Drisco8000) of the potential for material degradation. Degradation has been identified on pipe between one-half inch to two inches in diameter that was installed between 1978 and 1999 in desert-like environments in the southwestern United States. However, since root causes of the degradation have not been determined, PHMSA cannot say with certainty that this issue is isolated to these regions, operating environments, pipe sizes, or pipe installation dates. While the manufacturer has attempted to communicate with known or suspected users, PHMSA and the National Association of Pipeline Safety Representatives (NAPSR) have identified several operators currently using Drisco 8000 pipe who had not received communications about the issue. PHMSA is issuing this advisory bulletin to all operators of Drisco 8000 pipe in an effort to ensure they are aware of the issue, communicating with the manufacturer and their respective regulatory authorities to determine if their systems are susceptible to similar degradation, and taking measures to address it.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines Gas Piping Technology Committee (GPTC) Part 192, Appendix E.I

	PHMSA Gas Transmission Integrity Management FAQs: 2 Who must comply with the rule? 3 Does the rule apply to operators of transmission pipelines for gases other than natural gas? 7 Do the requirements of the rule apply to "idle" pipe? 9 Does the rule apply to gathering and other low-stress lines? 84 The Integrity Management Program portion of the rule [192.907] applies to all portions of a pipeline system that are in HCAs, including compressor stations, metering stations, and other equipment. What must an operator do to comply with the rule for these facilities? 150 What requirements must an operator meet if there are no high consequence areas on any of its transmission pipelines? 188 Are jurisdictional gathering lines covered? 247 For plastic transmission pipeline, must I meet all of the requirements in the sections specified in section 192.901 or just those requirements specifically directed at plastic pipe?
Guidance Information	1. The requirements of Subpart O apply to all gas transmission pipelines including compressor stations, metering stations, regulator stations, valve sets, and other fabricated assemblies. 2. All requirements of Subpart O apply to "line pipe." 3. For pipeline facilities other than "line pipe," an assessment may not necessarily be required. 4. Plastic transmission pipelines must be included in an integrity management program. The Preamble of the Federal Register notes that most of the requirements are applicable to metal pipelines, not plastic, only certain requirements apply to plastic gas transmission pipelines. Requirements for a continuing threat analysis (§§192.917, 192.937), a baseline assessment if a threat other than third-party damage is identified (§192.921), and additional preventive and mitigative measures (§192.935) apply to plastic gas transmission pipelines. (Federal Register / Vol. 68, No. 240 / Monday, December 15, 2003 / Rules and Regulations at Page 69801.)Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911
Examples of a Probable Violation or Inadequate Procedures	1. Failure to apply Subpart O requirements to all of the pipelines or components covered under the Subpart. Since 192.901 solely involves subpart scope, there are no requirements that can be violated, however cross referencing of this regulation is acceptable when citing other regulation for failure to apply requirements to pipelines or components. 2. Failure to include plastic gas transmission pipe in their Integrity Management Program. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Records. 3. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the IM program.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.903
Section Title	What definitions apply to this subpart?
Existing Code Language	The following definitions apply to this subpart: Assessment is the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment. Confirmatory direct assessment is an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment. Covered segment or covered pipeline segment means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in §192.3. Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation. High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows: (1) An area defined as- (i) A Class 3 location under §192.5; or (ii) A Class 4 location under §192.5; or (iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or (iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site. (2) The area within a potential impact circle containing- (i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or (ii) An identified site. (3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that

contains either an identified site or 20 or more buildings intended for human occupancy. (See Figure E.I.A. in Appendix E.)

(4) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy with a distance of 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for human occupancy is equal to 20 x (660 feet) [or 200 meters]/potential impact radius in feet [or meters]**2).

Identified site means each of the following areas:

(a) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or
(b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)- month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or
(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of (p*d \2\)), where `r' is the radius of a circular area in feet surrounding the point of failure, `p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and `d' is the nominal diameter of the pipeline in inches.

Note: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S-2001 (Supplement to ASME B31.8; incorporated by reference, see §192.7) to calculate the impact radius formula.

	Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-103A, 72 FR 4655, February 1, 2007
Interpretation Summaries	**Interpretation: WINDOT 192.903 1 Date: 08-15-2008** "Should the property boundary of a golf course be considered as a 'recreational facility' and therefore an identified site? It is our intention to only count golf course boundaries as identified sites where they are occupied by 20 or more persons within the PIR [potential impact radius] at one time for at least 50 days in any 12 month period. Is this an acceptable interpretation of the rule with regard to golf courses?" The gas integrity management program (IMP) rules are intended to protect identified sites occupied by 20 or more persons for specified periods. While it is possible for 20 or more persons to congregate near the boundary of a golf course inside a pipeline's PIR, these persons would likely be in transit and cannot truly be said to "occupy" the area as intended by the regulations. Therefore, such a location would not be an identified site per §192.903. PHMSA does not recommend using a golf course boundary to define an identified site because the boundary, in and of itself, is of little value. Instead, we recommend looking for sites such as a clubhouse, practice greens, or combinations of sites, such as a putting green near a tee box, to find areas on a golf course that are occupied by 20 or more persons for the specified periods. These could be identified sites.
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-03-03** **Identified sites for possible inclusion as high consequence areas (HCAs) in gas integrity management programs.** On August 6, 2002, RSPA/OPS published a final rule on how to identify the populated areas near a pipeline for which additional protections would be required (67 FR 50824). These "high consequence areas" (HCAs) include not only population areas already identified by pipeline operators through the longstanding Class location definitions, but also "identified sites," 49 CFR 192.761(f). Inclusion of identified sites is intended to pick up isolated population areas which are not picked up through the Class location process. These could include isolated nursing homes, schools, and campgrounds that may be close enough to the pipeline to be at risk should there be a pipeline failure. Commenters expressed concerns that what was intended to be a relatively simple task, identifying certain sites as high consequence areas, could become a never-ending search. RSPA/OPS is providing guidance in this advisory bulletin to provide the necessary clarification. With this guidance, operators can identify sites in preparation for required assessments and integrity management programs. The public will receive the assurance that the search for "identified sites" for inclusion in integrity management programs is clearly understood and thorough. The advisory bulletin provides guidance on a good faith effort in conducting this search.

Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Section 3 Gas Piping Technology Committee (GPTC) Part 192, Appendix E.I TTO-13, Potential Impact Radius Formulae for Flammable Gases Other Than Natural Gas Subject to 49 CFR 192, June 2005 TTO-14, Derivation of Potential Impact Radius Formulae for Vapor Cloud Dispersion Subject to 49 CFR 192, January 2005 PHMSA Gas Transmission Integrity Management FAQs: 17 What is an identified site? 119 Can I use normal operating pressure in my potential impact circle calculations if that pressure is significantly below MAOP? 144 What is the preferred method for calculating the Potential Impact Radius (PIR) of a leak of a non-flammable gas within the context of Pipeline Integrity Management? The regulation refers to ASME B31.8S-2004 Section 3.2 for calculation of PIR for gases other than natural gas. However, this document only deals with flammable gases. ASME B31.8S-2004 allows alternate models to be used for calculating impact radius, but provides no guidance as to preferred methods of modeling non-flammable or corrosive gases. 208 Is the derivation of the PIR equation publicly available? 211 What is the time period for the 20 persons in an area? 20 people for 10 min/day, 20 people for 2 hours/day, 20 people for 8 hours/day?
Guidance Information	1. Definitions included in IM plans must be consistent with those found in §192.903. 2. The formula for calculation of the potential impact radius must be consistent with 192.903 requirements [r = 0.69* (square root of (p*d \2\))] and the pressure used in the formula must be based on maximum allowable operating pressure (MAOP). 3. Equation for PIR can only be used for flammable gas. The factor (0.69) may vary according to the flammability of the actual gas compositions (see TTO-13 or ASME B31.8S-2004, Section 3.2). 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 5. Selected Final orders referencing §192.903 **a) Indiana Gas Co. Inc., [2-2007-1014], (July 15, 2010), Item 2B,** Operator failed to ensure that accurate maximum allowable operating pressures were used to determine the potential impact radius.

Examples of a Probable Violation or Inadequate Procedures	1. Definitions are not consistent with Part 192. 2. Records do not demonstrate the proper factor (i.e. - .69 for pipeline quality natural gas) for calculating potential impact radius was used. 3. MAOP was not used to calculate the PIR. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Records. 3. Formula for calculating PIR. 4. Records of product being transported. 5. Documented conversations with operator or contractor personnel. 6. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding IM definitions.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.905
Section Title	How does an operator identify a high consequence area?
Existing Code Language	(a) General. To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See appendix E.I. for guidance on identifying high consequence areas.) (b)(1) Identified sites. An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials. (2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites. (i) Visible marking (e.g., a sign); or (ii) The site is licensed or registered by a Federal, State, or local government agency; or (iii)The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public. (c) Newly identified areas. When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	

Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-03-03** **Identified sites for possible inclusion as high consequence areas (HCAs) in gas integrity management programs.** On August 6, 2002, RSPA/OPS published a final rule on how to identify the populated areas near a pipeline for which additional protections would be required (67 FR 50824). These “high consequence areas” (HCAs) include not only population areas already identified by pipeline operators through the longstanding Class location definitions, but also “identified sites,” 49 CFR 192.761(f). Inclusion of identified sites is intended to pick up isolated population areas which are not picked up through the Class location process. These could include isolated nursing homes, schools, and campgrounds that may be close enough to the pipeline to be at risk should there be a pipeline failure. Commenters expressed concerns that what was intended to be a relatively simple task, identifying certain sites as high consequence areas, could become a never-ending search. RSPA/OPS is providing guidance in this advisory bulletin to provide the necessary clarification. With this guidance, operators can identify sites in preparation for required assessments and integrity management programs. The public will receive the assurance that the search for “identified sites” for inclusion in integrity management programs is clearly understood and thorough. The advisory bulletin provides guidance on a good faith effort in conducting this search.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Section 3 Part 192, Appendix E.I Supplemental Guidance Appendix A.01, Protocol Guidance for the Identification of High Consequence Areas. PHMSA Gas Transmission Integrity Management FAQs: 17 What is an identified site? 18 Are there practical limits on an operator’s search for identified sites? 19 What are OPS expectations for operators to determine new or changed HCAs? 20 When must newly-identified HCAs be included in the program? 117 How often must an operator update its building density survey and list of identified sites to determine if new HCAs have been created? 120 Who is an appropriate safety authority for locating identified sites? 143 When determining "identified sites", does one have to consider standing traffic on roads/expressways under the "outside area or open structure" portion of the definition? If so, is there any guidance on how many people per vehicle should be used to compute the total of 20? 170 Must an operator continue to contact public safety officials in order to locate identified sites even if they don’t respond?

	176 Is a single home housing a disabled person considered an identified site? 191 If a pipeline is determined to fall within an HCA due to its class location, does the operator also have to identify identified sites? 195 How were the Fire Marshals notified of providing assistance in locating identified sites? Is there written communication (i.e., documentation) that operators can reference? 233 Does growth of an existing HCA, which introduces new length of pipeline segment into the HCA, constitute a "newly-identified HCA?"
Guidance Information	1. The §192.903 definitions provided are to determine identified sites that may be considered an HCA for a specific pipeline operator as the regulations for 192.905 are applied. 2. Each operator should have maps of their pipelines systems along with identified HCA's along the pipeline route. The operator must use system maps or other suitably detailed means to identify pipeline segment locations that are located in high consequence areas. 3. The operator's process must describe how to implement methods (1) and/or (2) in order to identify high consequence areas (HCAs). The operator's must document the method used for each portion of the pipeline system. 4. The operator must periodically look for changes along its pipeline to identify new HCAs. Additionally, those with no IM Program must continually take measures to look for new HCAs along their pipelines. 5. Operators were allowed to pro rate house counts in determining whether an HCA area existed. The time frame for this expired in December 2006 and prorating is no longer allowed. 6. Failure to have a process/procedure to identify HCAs or having an inadequate process describing how to apply Method 1 or 2 should be cited under §192.911(a). 7. Selected Final Orders Referencing §192.905: a) **Mardi Gras Pipeline, LLC, [4-2009-1007], (December 19, 2011), Item 1,** Operator failed to properly identify those segments of its gas transmission pipeline system that constituted HCAs. b) **Mardi Gras Pipeline, LLC, [4-2009-1007], (December 19, 2011), Item 2,** Operator failed to use public officials as a resource in the identification of areas that would qualify as "identified sites" within the potential impact radius along the pipeline. c) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 1,** Operator failed to describe and document in its IMP which method it had applied to each portion of its pipeline system to identify HCAs. The operator also failed to maintain records to support any decision, analysis or process developed and used to implement its IMP. Specifically, it alleged that the operator failed to keep documents supporting the process(es) that had been used to identify each HCA segment.

d) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 2A,** Operator failed to describe in its IMP which method it had applied to each portion of its pipeline to identify HCA segments. Specifically, the system maps and the Geographic Information System (GIS) used by the operator failed to establish a suitable means of documenting segment locations in HCAs.

e) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 2B,** Operator failed to use certain information available to it in cases where public officials with safety or emergency response or planning responsibilities had informed the company that they did not have information delineating identified sites. Specifically, the operator had failed, by December 17, 2004,to use visible markings, licensing or registration by a governmental agency, or listing on the Internet or other public available maps maintained by governmental entities to delineate identified sites in lieu of obtaining relevant information from public officials. Also, the operator did not have procedures on how it located identified sites using such alternative sources of information.

f) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 4,** Operator failed to properly identify HCA areas using one of the methods described in paragraph (1) or (2) of §192.903. There were four separate violations:

Item 4A, Operator failed to properly apply Method 1 in delineating HCAs, insofar as the full length of Class 3 and 4 locations was not included in the HCAs.

Item 4B, Operator failed to properly identify HCA areas using Method 1 under §192.903. Specifically, the operator failed to properly identify HCAs under portion of Method 1 which calls for the identification of areas "in a Class 1 or 2 location where the potential impact circle contains an identified site". Documentation reviewed during the inspection showed identified sites on the operator's Transco system that the company had failed to include in HCAs. The HCA identification process was flawed insofar as the company's field personnel were not even trained in the HCA identification process until well after December 17, 2004.

Item 4C, Operator failed to properly identify HCA areas using Method 1. Specifically, the operator defined the term "day" as a continuous 8 hour period, for purposes of determining whether structures or outdoor areas qualified as identified sites. This definition was inconsistent with the regulation, insofar as the 20 or more persons criterion applied to the presence of people at a particular location at any point in time.

Item 4D, Operator failed to properly designate HCA areas as defined in §192.903. Specifically, the operator failed to apply the axial extension of the potential impact circle along the length of the pipeline, from the outermost edge of the first potential impact circle containing either an identified site or 20 or more buildings intended for human occupancy, to the outermost edge of the last contiguous potential impact circle containing such sites.

	g) Chevron Pipe Line Co., [5-2007-1007], (June 15, 2009), Item 1A, Operator failed to follow its procedures for inputting pipeline data into the GIS. The GIS contained inaccurate information on the high consequence areas and covered segments. **h) Chevron Pipe Line Co., [5-2007-1007], (June 15, 2009), Item 1B,** Operator failed to determine if certain buildings, already classified as identified sites, met the Class 3 location criteria. The operator had no documents showing that certain structures, selected by the OPS inspector from aerial photographs, had received an identified site determination. **i) Alyeska Pipeline Service Co., [5-2008-0002], (March 15, 2010), Item 1A,** Operator failed to have a process for identifying HCAs along its fuel gas line. **j) Alyeska Pipeline Service Co., [5-2008-0002], (March 15, 2010), Item 1C,** Operator failed to have a written procedure that must be taken if a new HCA is identified.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to follow procedures when identifying HCAs. 2. Records do not show which Method was used to identify HCAs. 3. Records demonstrate that the Method used was not properly applied. 4. HCAs were not identified by December 17, 2004. (§192.907) 5. A previously missed HCA was inappropriately designated as a "newly identified" HCA. 6. Changes along the pipeline (e.g., population growth) were not accounted for in the identification of HCAs. 7. Failure to communicate with public officials in determining identified sites. 8. The prorate method to determine an HCA continued past the December 17, 2006 time period. (§192.903) 9. Failure to maintain a list of their covered pipeline segments. 10. No process/procedure to identify new areas around a pipeline segment not previously identified as a high consequence area. 11. Failure to complete an evaluation for the newly identified areas using Method (1) or (2). 12. Failure to incorporate the newly identified area into the baseline assessment plan within one year from the date the area was identified. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Records. 3. HCA determinations/maps. 4. Procedures for determining HCA’s for newly identified areas. 5. Baseline assessment plan. 6. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding the identification of HCAs.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.907(a)
Section Title	What must an operator do to implement this subpart?
Existing Code Language	(a) General. No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in §192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Section 2 PHMSA Gas Transmission Integrity Management FAQs: 72 When must the Baseline Assessment Plan and Framework be completed? 74 What is the difference between an acceptable Integrity Management Framework and a fully developed Integrity Management Program? 140 What level of detail does OPS expect to see in initial IM frameworks for each of the required program elements? 167 How should the operator address "must" and "shall" statements in the standard? In some cases, the standard provides for an alternative action if the "must" and "shall" statements are not implemented? 179 How long does an operator that has had no HCAs, and therefore no integrity management program, have to develop an integrity management program after it discovers a new HCA?

	238 What documentation must I include in my IM program to describe a "process" required by the rule? 239 How much detail must I include when the rule requires that I "justify" an action or decision? 244 What is the OPS position with regard to implementation of "should" statements in industry standards that are invoked by the rule?
Guidance Information	1. An operator is expected to make continual improvements to the plan each year that it is in effect. 2. Operator plans are expected to implement "should", “must”, and “shall statements in industry (consensus) standards that are invoked by the rule. A failure to implement referenced standards should be cited under §192.7(a) rather than §192.907(a). (see also Supplemenatry Guidance for Protocol L.03). 3. 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 5. Selected Final Orders Referencing §192.907(a): a) **Indiana Gas Co. Inc., [2-2007-1014], (July 15, 2010), Item 1**, Operator failed to follow its own written procedures and the requirements of B31.8S and its appendices. Operator violated §192.907(a) and (b) by failing to follow its own written procedures. b) **Columbia Gas Transmission Corp., [3-2009-1018], (November 16, 2010), Item 1A**, Operator failed to follow its written integrity management program. Specifically, the operator did not identify all of the HCA locations along its 12 inch UM 10 pipeline system by the December 17, 2004 deadline. c) **West Texas Gas Inc., [4-2007-1002], (October 28, 2008), Item 1**, Operator failed to develop a written integrity management program by December 17, 2004. d) **El Paso Natural Gas Co., [4-2007-1007], (March 10, 2011)**, **Item 2,** Operator failed to develop and follow an integrity management program by December 17, 2004. Specifically, the operator failed to identify all HCA areas known as “identified sites” and certain other areas meeting the HCA definition on the basis of having 20 or more structures or certain class location changes. e) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 3**, Operator failed to meet the December 17, 2004 deadline for developing and following a written IMP that contained all the elements described in §192.911 and that addressed the risks on each covered segment. Specifically, the operator’s records revealed that as of April and May 2005, the company’s HCA identification process was still incomplete. f) **CPN Pipeline Co., [5-2007-1006], (December 16, 2009), Item 2**, Operator failed to develop a written integrity management program that contained all the elements in §192.911 by December 17, 2004. Specifically, the IMP did not identify all HCAs.

	g) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 7,** Operator failed to follow the requirements of Subpart O of Part 192 and B31.8S in the development and implementation of its IMP. Specifically, the operator failed to identify and evaluate all potential threats to each covered segment as described in §192.917(a) by the December 17, 2004 deadline. The operator's risk assessment and subsequent baseline assessment decisions were based on a risk model that failed to document the basis for threat-weighting factors, that failed to consider interacting threats, and that failed to document the elimination of certain threats until after the risk ranking had been completed. h) **Southern Star Central Gas Pipeline, Inc., [4-2012-1013], December 27, 2012, Item 1,** Operator failed to follow its written integrity management (IM) program. Specifically, the Notice alleged that Southern Star's IM program called for a "primary" review of the program once every four years, and a "secondary" review in the year following the primary review and every two years in which a primary review was not conducted. Such quality assurance measures are required to be a part of the IM program by § 192.911(l). The Notice alleged that Southern Star failed to conduct and document either a primary or secondary level review of its IM program from 2006 until the PHMSA inspection in 2011.
Examples of a Probable Violation or Inadequate Procedures	1. The written Integrity Management Plan was inadequate. 2. Failure to treat "should", "must", and "shall" statements in invoked standards as requirements (cite against §192.7(a), see also Supplemenatry Guidance for Protocol L.03). 3. Integrity Management Plan did not include all of the elements in 192.911. 4. Integrity Management Plan did not address all of the risks associated with their covered pipelines. 5. Integrity Management Plan did not include a process for implementing each program element. 6. Integrity Management Plan did not include a process for determining how relevant decisions will be made and by whom. 7. Integrity Management Plan did not include a time line for completing any work identified to implement each program element. 8. Integrity Management Plan did not include a process for how information gained from experience will be continuously incorporated into the program. 9. Failure to have a detailed and comprehensive program. 10. Failure to follow written Integrity Management program. 11. Failure to make continual improvements to the Integrity Management program as new information became available. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Records. 3. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding development of the Integrity Management Plan.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.907(b)
Section Title	What must an operator do to implement this subpart?
Existing Code Language	(b) Implementation Standards. In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (incorporated by reference, see §192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME/ANSI B31.8S, the requirements in this subpart control.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Section 2 PHMSA Gas Transmission Integrity Management FAQs: 155 In several places, the rule requires that operators follow Appendices in ASME/ANSI B31.8S. The title of both Appendices A and B in the standard indicate they are non-mandatory. Must the requirements in these Appendices be followed verbatim? 167 How should the operator address "must" and "shall" statements in the standard? In some cases, the standard provides for an alternative action if the "must" and "shall" statements are not implemented. 244 What is the OPS position with regard to implementation of "should" statements in industry standards that are invoked by the rule?
Guidance Information	1. The written Integrity Management plan is a combination of both the federal pipeline safety rules and industry (consensus) standards that are incorporated by reference. An operator can chose to follow an equivalent standard or practice if the operator provides written documentation to demonstrate that they provide an equivalent level of safety. 2. The operator must reference the incorporate by reference edition of ASME B31.8S-2004.

	3. Operator plans are expected to implement "should", “must”, and “shall statements in industry (consensus) standards that are invoked by the rule. The requirements of ASME B31.8S-2004 became mandatory when the Standard was incorporated by reference in Part 192. 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 5. Selected Final Orders Referencing §192.907(b): a) **Indiana Gas Co. Inc., [2-2007-1014], (July 15, 2010), Item 1,** Operator failed to follow its own written procedures and the requirements of B31.8S and its appendices. Operator violated §192.907(a) and (b) by failing to follow its own written procedures.
Examples of a Probable Violation or Inadequate Procedures	1. Integrity Management Plan did not address all of the mandatory requirements of ASME B31.8S-2004 and its appendices. 2. Failure to treat "should", "must", and "shall" statements in invoked standards as requirements (cite against §192.7(a)). 3. Integrity Management plan used an alternative standard or practice without demonstrating that an equivalent level of safety was provided. 4. Failure to follow the requirements of ASME/ANSI B31.8S-2004 and its appendices. 5. The operator could not provide written documentation that an equivalent standard provided an equal level of safety. 6. The operator failed to use the incorporated by reference standard. 7. Industry (consensus) standard was selected over the Integrity Management subpart of the code in resolving a conflict between the two standards/requirements where the industry (consensus) standard was less restrictive than the code. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Copies of alternative/equivalent standard utilized. 3. Documentation of justification that the alternative standard or practice provided an equivalent level of safety. 4. Records. 5. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of ASME/ANSI B31.8S-2004 and its appendices.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.909
Section Title	How can an operator change its integrity management program?
Existing Code Language	(a) General. An operator must document any change to its program and the reasons for the change before implementing the change. (b) Notification. An operator must notify OPS, in accordance with §192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-05-04** **Integrity Management Notifications for Gas Transmission Lines.** The integrity management regulations for gas transmission lines (49 CFR part 192, subpart O) require that operators notify OPS of each of the following events: 1. When operators make changes to their integrity management programs that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements (49 CFR 192.909(b)). 2. When operators plan to use technology other than in-line inspection, pressure testing, or direct assessment to perform assessments of pipeline integrity (49 CFR 192.921(a)(4) and 192.937(c)(4)). 3. When operators cannot meet the schedule required by the rule for remediating any identified condition and cannot provide safety through a temporary reduction in operating pressure or other action (49 CFR 192.933(c)). In addition, operators must send notifications of these events to each state or local pipeline safety agency that either regulates the safety of the transmission line involved or inspects the line under an interstate agent agreement with OPS. Operators may notify OPS by mail, facsimile, or the on-line database (49 CFR 192.949). Notification of state agencies should be done according to state agency procedures.

Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines Gas Piping Technology Committee (GPTC) PHMSA Gas Transmission Integrity Management FAQs: 30 Will operators need to seek waivers from OPS in order to change assessment schedules after the initial Baseline Assessment Plan has been developed? 31 Section 192.909(b) requires that operators notify OPS of program changes that may modify the schedule for carrying out the program elements. Must operators notify OPS every time they change their assessment schedules? 32 Should operators archive previous versions of their baseline assessment plans so OPS can track changes to these plans over time? 98 When must notifications be submitted? 111 What level of change satisfies the terms "significantly modify" or "substantially affect" as used under subpart 192.909(b) regarding notification requirements for changes to an operator's integrity management plan? 183 If an operator initially selects method 1 to identify HCAs and later changes to method 2 for the same portion of its system, does this constitute a change in IMP that needs to be communicated to OPS/state?
Guidance Information	1. Notifications must be submitted to PHMSA and appropriate state regulatory authority for "any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements." The operator's IM Program plan should specify how it defines these types of changes. 2. The operator must maintain records of notifications that have been submitted to PHMSA or State agencies. 3. Integrity Management Program is required to have a Management of Change process. A failure to have processes/procedures meeting this requirement should be cited under §192.911(k). A failure to implement Management of Change requirements would be cited under §192.909. 4. Selected Final Orders Referencing §192.909: **a) Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 2,** Operator failed to document changes made to its Integrity Management Program. Specifically, the operator's Management of Change program lacked procedures and documentation requirements for "technical, physical, procedural, and organizational changes" in its IMP.
Examples of a Probable Violation or Inadequate Procedures	1. Integrity Management plan did not define the types of changes that require notification. 2. A change requiring notification was made to the Integrity Management Program and no notification was made to PHMSA. 3. Failure to provide notification within 30 days after adoption of a change in the IM program requiring notification. 4. Failure to provide notification of a "significant" change to its IM Program to the State or local pipeline safety authority when either a covered segment is

	located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that state. 5. Failure to have correct information on how to submit change notifications to PHMSA. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. A description of the "significant" change made to the IMP. 3. Documentation of a "significant" change that was not submitted to PHMSA as a notification. 4. Definition of a "significant" change. 5. IM program change log. 6. Records. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding documentation of IM Program changes and submittal of notifications.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.911
Section Title	What are the elements of an integrity management program?
Existing Code Language	An operator's initial integrity management program begins with a framework (see §192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (incorporated by reference, see §192.7) for more detailed information on the listed element.) (a) An identification of all high consequence areas, in accordance with §192.905. (b) A baseline assessment plan meeting the requirements of §192.919 and §192.921. (c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment. (d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929. (e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment. (f) A process for continual evaluation and assessment meeting the requirements of §192.937. (g) If applicable, a plan for confirmatory direct assessment meeting the requirements of §192.931. (h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area. (i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of §192.945 (j) Record keeping provisions meeting the requirements of §192.947. (k) A management of change process as outlined in ASME/ANSI B31.8S, section 11. (l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12. (m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by-- (1) OPS; and

	(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement. (n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to-- (1) OPS; and (2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement. (o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks. (p) A process for identification and assessment of newly-identified high consequence areas. (See §192.905 and §192.921.)
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 2, 9, 10, 11, and 12 Gas Piping Technology Committee (GPTC) PHMSA Gas Transmission Integrity Management FAQs: 76 What is an Integrity Management Program?
Guidance Information	1. The preamble to the Federal Register rule notes that an operator must include certain minimum elements in its integrity management program. Minimum elements are those listed in the rule and when referenced in the rule those in the ASME/ANSI B31.8S-2004 standard. (Federal Register / Vol. 68, No. 240 / Monday, December 15, 2003 / Rules and Regulations at Page 69802.) 2. Operator's are required to make continual improvements to their IM program. The operator's current IM program must have matured beyond the initial framework level. In some cases, portions of the IM Plan that have not been implemented may still be at the "framework" level. 3. Selected Final Orders Referencing §192.911: a) **Carolina Gas Transmission Corp., [2-2007-2010], (July 15, 2010), Item 4A,** Operator failed to develop and implement an IMP that included a communications plan with procedures on how safety concerns that had been raised by OPS or State authorities were to be documented, tracked, and addressed. b) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 3,**

	Operator failed to have an IMP that contained an MOC Plan with specific procedural or documentation requirements to address changes to the IMP. c) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 4,** Operator failed to have an IMP that contained a comprehensive quality assurance/quality control process, as required by Section 12 of B31.8S. d) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 6,** Operator failed to include in its IMP a communication plan that included the elements of Section 10 of B31.8S. Specifically, the operator failed to specify how the company documented and routinely communicated IMP issues internally and how it acted upon requests made by PHMSA and State authorities. e) **Mardi Gras Pipeline, LLC, [4-2009-1007], (December 19, 2011), Item 4,** Operator failed to have an integrity management program containing a communication plan that included the elements of Section 10 of B31.8S. Specifically, the operator was not unable to provide OPS with a copy of its communication plan, nor was it able to present evidence that a plan had been developed. f) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 13C,** Operator failed to have an IMP that included an internal communication procedure. Specifically, it alleged that the operator did not have a communication plan having the elements listed in B31.8S. g) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 13D,** Operator failed to have an IMP that contained a communication plan that included procedures for addressing safety concerns raised by OPS or State authorities. h) **CPN Pipeline Co., [5-2007-1006], (December 16, 2009), Item 4A,** Operator failed to include a Management of Change process in its IMP. Specifically, the operator's IMP process for MOC did not require interface with the operator's written operations and maintenance procedures pertaining to MOC. i) **CPN Pipeline Co., [5-2007-1006], (December 16, 2009), Item 4B,** Operator failed to include an MOC process in its IMP. Specifically, the operator's MOC process failed to require the company to evaluate procedural changes that could impact or interface with the IMP. j) **CPN Pipeline Co., [5-2007-1006], (December 16, 2009), Item 4C,** Operator failed to have and follow an MOC process. Specifically, the operator failed to follow its MOC process for the installation of a low pressure switch on the Road 17 Line Break valve. The MOC process required the "piping and instrumentation diagram" be updated, but the company had documented the job was complete on the MOC form without updating the diagram. k) **Chevron Pipe Line Co., [5-2007-1007], (June 15, 2009), Item 3A,** Operator's IMP did not include a means for monitoring the effectiveness of, or need for improvements in, its quality assurance process. Specifically, the operator failed to correct deficiencies that had been discovered during prior independent audits.

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l) Alyeska Pipeline Service Co., [5-2008-0002], (March 15, 2010), Item 1A, Operator failed to have a process for identifying HCAs along its fuel gas line.
m) Alyeska Pipeline Service Co., [5-2008-0002], (March 15, 2010), Item 1B, Operator failed to have a written procedure for applying the potential impact radius method to determine if an HCA would be affected by a failure of the company’s fuel gas line.
n) Alyeska Pipeline Service Co., [5-2008-0002], (March 15, 2010), Item 1C, Operator failed to have a written procedure for the steps that must be taken if a new HCA is identified.
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<tr><td>Examples of a Probable Violation or Inadequate Procedures</td><td>
1. Integrity Management Plan did not contain all of the elements of 192.911.
2. Integrity Management Plan was not comprehensive in that it did not include all of the pipeline operations/segments.
3. Integrity Management plan did not include one or more of the following elements, or one or more of the following elements was inadequate:
a. An identification of all high consequence areas;
b. A baseline assessment plan;
c. An identification of threats to each covered pipeline segment;
d. A direct assessment plan, if applicable;
e. Provisions for remediating conditions found during an IM assessment;
f. A process for continual evaluation and assessment;
g. A plan for confirmatory direct assessment, if applicable;
h. Provisions for adding preventive and mitigative measures to protect the high consequence area;
i. A performance plan that includes performance measures;
j. Record keeping provisions;
k. A management of change process;
l. A quality assurance process;
m. A communication plan;
n. The communication plan did not include procedures for notification to PHMSA or State agencies;
o. Procedures for providing, by electronic or other means, a copy of the operator’s risk analysis or integrity management program;
p. Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks; and/or
q. A process for identification and assessment of newly identified high consequence areas;
r. There was no process for incorporating new information/data in a timely and/or effective manner.
4. Failure to follow the Integrity Management plan or one of its elements.

Depending on the circumstances, some of the examples listed in this section may be inaequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.
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Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Documentation regarding changes in the Integrity Management plan. 3. Records showing new information that was not incorporated into the IM program, as appropriate. 4. Notification records. 5. Copies of procedures to accomplish each of the identified elements. 6. Records. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding development and maintenance of the IM Plan.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.913
Section Title	When may an operator deviate its program from certain requirements of this subpart?
Existing Code Language	(a) General. ASME/ANSI B31.8S (incorporated by reference, see §192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section. (b) Exceptional performance. An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions. (1) To deviate from any of the requirements set forth in paragraph (c) of this section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements-- (i) A comprehensive process for risk analysis; (ii) All risk factor data used to support the program; (iii) A comprehensive data integration process; (iv) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart; (v) A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program; (vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments; (vii) Semi-annual performance measures beyond those required in §192.945 that are part of the operator's performance plan. (See §192.911(i).) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951; and (viii) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments. (2) In addition to the requirements for the performance-based plan, an operator must-- (i) Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-

	based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment. (ii) Remediate all anomalies identified in the more recent assessment according to the requirements in §192.933, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment. (c) Deviation. Once an operator has demonstrated that it has satisfied the requirements of paragraph (b) of this section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this subpart only in the following instances. (1) The time frame for reassessment as provided in §192.939 except that reassessment by some method allowed under this subpart (e.g., confirmatory direct assessment) must be carried out at intervals no longer than seven years; (2) The time frame for remediation as provided in §192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 2, 4.2.2, 5.10, 7.2.5, and 9 Gas Piping Technology Committee (GPTC) Supplemental Guidance Appendix F.01, Continual Evaluation and Assessment Supplemental Guidance Appendix F.05, White Paper - Exceptional Performance PHMSA Gas Transmission Integrity Management FAQs: 173 Can a CDA be credited as a second assessment if an operator desires to move to a performance-based program? 227 How is risk assessment and data integration conducted in performance-based programs expected to differ from that in a prescriptive approach?
Guidance Information	1. The preamble to the Federal Register Notice notes that an operator can deviate from its prescriptive Integrity Management program of ASME/ANSI B31.8S-2004 and of Subpart O as long as they meet the requirements of §192.913: *ASME/ANSI B31.8S allows an operator to deviate from some specific provisions of the standard if the operator has a mature integrity*

	management program that addresses the intent of those provisions in a different manner. This is called a performance-based program, as compared to a prescriptive program (i.e., one meeting the literal provisions of the standard)… *Once an operator has demonstrated that it has satisfied the requirements for exceptional performance, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of Subpart O in two instances:* *• The time frame for reassessment as provided in § 192.939 except that reassessment by an allowable method (e.g., confirmatory direct assessment) must be carried out at intervals no longer than seven years; and* *• The time frame for remediation as provided in § 192.933, as long as the operator demonstrates that the revised time frame will not jeopardize the safety of the covered segment.* (Federal Register / Vol. 68, No. 240 / Monday, December 15, 2003 / Rules and Regulations at Page 69803.) 2. An operator can deviate from its prescriptive Integrity Management program of ASME/ANSI B31.8S-2004 and of Subpart O as long as they meet the requirements of §192.913. 3. Section 192.913(a) allows an operator that uses a performance-based approach to deviate from some requirements of the rule. Operators must demonstrate "exceptional performance," meeting requirements in section 192.913(b)(1), to qualify for a performance-based approach. Operators must also have completed at least two integrity assessments on each covered pipeline segment to be included in the performance-based approach, and must have remediated all of the anomalies identified in the most recent assessment in accordance with the requirements of 192.933. Once an operator has demonstrated that it has met these requirements, it may establish reassessment intervals that are longer than the maximum otherwise allowed in 192.939 and may extend the time for remediation specified in 192.933, if there is sufficient technical basis for doing so. 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. IM program deviated from certain requirements of the regulations but did not have a process/procedure in place that meets or exceeds the performance-based requirements of ASME/ANSI B31.8S-2004. 2. Performance-based process/procedure did not include a comprehensive process for risk analysis. 3. The records do not demonstrate that the performance based program consider all 21 of the threats associated with the nine threat categories in the standard. 4. Performance-based process/procedure did not include all risk factor data to support the program. 5. Performance-based process/procedure did not include a comprehensive data integration process. 6. Performance-based process/procedure did not include a procedure for applying

	lessons learned from assessment of covered segments to pipeline segments not covered by this subpart. 7. Performance-based process/procedure did not include a procedure for evaluating every incident including its cause. 8. Performance-based process/procedure did not include a performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments. 9. Performance-based process/procedure did not include semi-annual performance measures beyond those required in §192.945. 10. Performance-based process/procedure did not include an analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments. 11. Procedures did not specify or document requirements for implementing extended intervals under a performance-based program. 12. Inability to demonstrate exceptional performance. 13. The requirements of §192.913(b) were not required to have been met prior to implementing deviations from the repair timeframes by demonstrating exceptional performance. 14. The requirements in §192.913 were not satisfied when using exceptional performance to deviate from maximum reassessment interval requirements. 15. At least two integrity assessments on each covered segment included under the performance-based approach were not completed. 16. Anomalies were not remediated per §192.933 in the more recent assessment used for credit under the performance-based approach. 17. Results and lessons learned were not incorporated into the data integration and risk assessment from the more recent assessment used for credit under the performance-based approach. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Performance-based criteria. 3. Documentation of exceptional performance. 4. Prior integrity assessments of the segments included in the exceptional performance. 5. Records. 6. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the performance-based integrity management process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.915
Section Title	What knowledge and training must personnel have to carry out an integrity management program?
Existing Code Language	(a) Supervisory personnel. The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible. (b) Persons who carry out assessments and evaluate assessment results. The integrity management program must provide criteria for the qualification of any person-- (1) Who conducts an integrity assessment allowed under this subpart; or (2) Who reviews and analyzes the results from an integrity assessment and evaluation; or (3) Who makes decisions on actions to be taken based on these assessments. (c) Persons responsible for preventive and mitigative measures. The integrity management program must provide criteria for the qualification of any person-- (1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or (2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 11, and 12.2. Gas Piping Technology Committee (GPTC) ASNT ILI-PQ-2005, In-line Inspection Personnel Qualification and Certification, (reaffirmed in 2010).

Guidance Information	1. The preamble to the Federal Register Notice notes that supervisory personnel with integrity management responsibilities must have a thorough knowledge of the program and the requirements apply to both operator and contractor personnel: *The rule has requirements for supervisory personnel and for other personnel with integrity management program functions. These requirements apply to both personnel employed by the operator and contractor personnel used to perform integrity management program functions.* (Federal Register / Vol. 68, No. 240 / Monday, December 15, 2003 / Rules and Regulations at Page 69803.) 2. Personnel qualification requirements must be identified for anyone who is involved in the integrity management program. The requirement to identify qualifications applies to both operator and vendor personnel. 3. Personnel having supervisory authority that relates to the operator's integrity management process must meet documented qualification requirements for the aspects of the IM program under their authority. 4. Personnel performing integrity management tasks may include operator personnel, contractors, or vendors, all of whom are expected to be competent, aware of the program and all of its activities and are to be properly trained and qualified to execute the activities within the IMP. 5. Some of the IMP activities may be considered covered tasks and be included as part of the operator's OQ program (e.g., preventive and mitigative measures including pipeline locates and markings, excavations, launching and receiving an ILI tool, performing a pressure test, and conducting a direct assessment). The use of non-qualified personnel, or direct supervision of non-qualified personnel, to perform covered tasks should be enforced against Subpart N of Part 192. 6. The location of various qualification records could be in several different areas of the operator's data storage systems or manuals. 7. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 8. Selected Final Orders Referencing §192.915: a) **West Texas Gas Inc., [4-2007-1002], (October 28, 2008), Item 2,** Operator failed to include provisions in its IMP provisions to ensure that each supervisor whose responsibilities relate to the IMP possesses and maintains the necessary knowledge and training to perform his duties. b) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 7,** Operator failed to have procedures or program qualification requirements documented in its IMP for personnel who carried out assessments or evaluated assessment results. c) **Mardi Gras Pipeline, LLC, [4-2009-1007], (December 19, 2011), Item 5,** Operator failed to have an integrity management program that ensured that company personnel had the requisite knowledge and training to carry out the program. Specifically, the operator's program failed to provide that

	supervisory personnel, persons who carried out integrity assessments, and persons responsible for developing P&M measures were properly trained and experienced to carry out their responsibilities.
Examples of a Probable Violation or Inadequate Procedures	1. No process/procedure existed to document personnel qualification criteria for activities performed within the Integrity Management program. 2. Personnel involved with integrity management, as defined in 192.915, were not required to be qualified for their assigned responsibilities. 3. No process/procedure existed to qualify supervisory personnel in integrity management for the areas of their responsibility. 4. No process/procedure existed to qualify personnel to carry out assessments and evaluate assessment results. 5. No process/procedure existed to qualify personnel who implement or supervise preventive and mitigative measures. 6. The operator did not follow their qualification process/procedures. 7. Supervisory personnel do not demonstrate a thorough knowledge of the Integrity Management Program and the areas for which they are responsible. 8. Supervisory personnel were not trained or experienced in the area for which they were responsible. 9. Qualified vendors and/or individuals were not used to perform assessments or review assessment results. 10. Qualified personnel were not utilized for assignments involving integrity management as required by 192.915. 11. Training program requirements were not linked to the integrity management program. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. OQ program and records. 3. List of covered tasks. 4. Training and qualification records of IM personnel covered under this section. 5. Records. 6. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ECDA pre-assessment process.
Other Special Notations	The operator’s OQ program may also need to be evaluated under this section, Subpart N, to determine if qualification is adequate.

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.917(a)
Section Title	How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?
Existing Code Language	(a) Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 2, which are grouped under the following four categories: (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking; (2) Static or resident threats, such as fabrication or construction defects; (3) Time independent threats such as third party damage and outside force damage; and (4) Human error.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-13-04** **T.D. Williamson, Inc. Leak Repair Clamp Recall** **June 17, 2013** PHMSA advisory to alert all pipeline operators of a T.D. Williamson, Inc. (TDW) Leak Repair Clamp (LRC) recall issued by TDW on June 17, 2013. The recall covers all TDW LRCs of any pressure class and any size. The LRCs may develop a dangerous leak due to a defective seal. Hazardous liquid and natural gas pipeline operators should verify if they have any TDW LRCs subject to the recall by reviewing their records and equipment for installation of these LRCs. **Advisory Bulletin ADB-12-11** **Reporting of Exceedances of Maximum Allowable Operating Pressure.** PHMSA is issuing this Advisory Bulletin to inform owners and operators of gas transmission pipelines that if the pipeline pressure exceeds maximum allowable operating pressure (MAOP) plus the build-up allowed for operation of pressure-limiting or control devices, the owner or operator must report the exceedance to PHMSA on or before the fifth day following the date on which the exceedance

occurs. If the pipeline is subject to the regulatory authority of one of PHMSA¿s State Pipeline Safety Partners, the exceedance must also be reported to the applicable state agency.

Advisory Bulletin ADB-12-06

Verification of Records establishing MAOP and MOP

PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities to verify their records relating to operating specifications for maximum allowable operating pressure (MAOP) required by 49 CFR 192.517 and maximum operating pressure (MOP) required by 49 CFR 195.310. This Advisory Bulletin informs gas operators of anticipated changes in annual reporting requirements to document the confirmation of MAOP, how they will be required to report total mileage and mileage with adequate records, when they must report, and what PHMSA considers an adequate record. In addition, this Advisory Bulletin informs hazardous liquid operators of adequate records for the confirmation of MOP.

Advisory Bulletin ADB-11-01

Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation.

PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities of their responsibilities, under Federal integrity management (IM) regulations, to perform detailed threat and risk analyses that integrate accurate data and information from their entire pipeline system, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP), and to utilize these risk analyses in the identification of appropriate assessment methods, and preventive and mitigative measures.

Advisory Bulletin ADB-03-05

Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines.

RSPA's Office of Pipeline Safety (OPS) is issuing this advisory notice to owners and operators of gas and hazardous liquid pipelines to consider the threat from stress corrosion cracking (SCC) when developing and implementing Integrity Management Plans. Operators should determine whether their pipelines are susceptible to SCC and assess the impact of SCC on pipeline integrity. Based on this evaluation, an operator should prioritize application of additional in-line inspection and hydrostatic testing and take actions to remediate problem areas.

Alert Notice ALN-88-01

The purpose of this letter is to advise you of recent findings relative to factors contributing to operational failures of pipelines constructed with Electric Resistance

	Weld (ERW) pipe manufactured prior to 1970. If you have such pipe in your pipeline system, the Office of Pipeline Safety (OPS) recommends that you read the enclosed "ALERT NOTICE: and take appropriate preventive steps.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 2.2, Appendix A. Mechanical Damage in Pipelines, Michael Baker Jr., Inc., April 2009 Pipeline Corrosion, Final Report, Michael Baker Jr., Inc., November 2008 Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, Final Report No. 05-12R, John F. Kiefner, April 26, 2007. Pipe Wrinkle Integrity Determination, TTO-04, Michael Baker Jr. Inc., May 2003. Stress Corrosion Cracking Study, TTO-08, Michael Baker Jr. Inc., January 2005. Dent Study, TTO-10, Michael Baker Jr., November 2004. Pipe Wrinkle Study, TTO-11, Michael Baker Jr. Inc., October 2004. Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, TTO 5, Michael Baker Jr., April 2004. Integrity Characteristics of Vintage Pipelines, INGAA Foundation, Inc., November 2004. NACE RP-0102-2002, In Line Inspection of Pipelines (not incorporated by reference). Supplemental Guidance Appendix B.02, Typical Risk Factors Associated with Pipelines. Supplemental Guidance Appendix B.03, ILI Tool Characteristics and Attributes. Supplemental Guidance Appendix B.05, Electric Resistance Welded Piping. Supplemental Guidance Appendix B.07, White Paper - Assessing for Third Party Damage. Supplemental Guidance Appendix C.01, Protocol Guidance for Identification of Threats, Data Integration, and Risk. PHMSA Gas Transmission Integrity Management FAQs: 83 Will operators be expected to consider external conditions such as earthquake fault lines or mining subsidence in their integrity management program? 141 A spike test can be very useful for assessing some threats, including seam issues. Can a spike test be used as an assessment method? 218 If DA is not currently accepted as a primary assessment method for third party damage, and the threat of third party damage is present, does the rule require that DA always be accompanied by either a pressure test, or ILI, or another assessment method that is capable of assessing third party damage?

	219 Are integrity assessments required for manufacturing and construction defects, including seam defects, if the pipeline has been pressure tested in accordance with Subpart J? 220 Are assessments required for manufacturing and construction defects, including seam defects, if the pipeline has not been pressure tested in accordance with Subpart J? 221 Relative to the requirement in 192.917(e)(3)(i), how much pressure increase (above the maximum experienced in the preceding five years of operation) will trigger the requirement to treat the segment as high risk for purposes of integrity assessments? 231 What 5-year period must I consider to establish a reference pressure for stability of manufacturing and construction defects?
Guidance Information	1. All pipelines are considered to contain manufacturing and construction defects. 2. The threat for seam defects must consider the requirements of § 192.917(e)(4). 3. A segment of pipe with a successful Subpart J pressure test, with no intervening failures determined to be caused by manufacturing or construction defects, could be considered as stable provided that the operating conditions have not changed. 4. All pipelines are potentially subject to both internal and external corrosion. The degree of potential corrosion characterized by the operator needs to be supported by documentation and actual pipeline data. For example, past corrosion failures substantiate the potential for corrosion, or the need for inhibitors substantiates the potential for internal corrosion. 5. Pipelines operated by bypassing processing equipment or with out-of-service processing equipment (e.g., liquid removal facilities) should be considered susceptible to internal corrosion unless the operator can demonstrate that internal corrosion is not a risk. 6. Operators must justify eliminating threats. The fact a failure has never occurred as a result of a particular threat, or a lack of data, is not sufficient justification for eliminating a threat. 7. All covered segments including dead legs, low spots, non-piggable pipelines, etc. should be included in the threat identification. 8. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 9. Selected Final Orders Referencing §192.917(a): a) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 8,** Operator failed to identify and evaluate in its IMP all potential threats to each covered segment. Specifically, the operator failed: (1) to develop and implement a systematic process for evaluating threats for specific pipeline segments; (2) to adequately justify the elimination of "cyclic fatigue or other loading conditions"; and (3) to develop a procedure for analyzing interacting threats. No basis was found to support allegation (1) and insufficient evidence was produced to support allegation (2). Allegation (3) was upheld. b) **Centerpoint Energy Gas Transmission, [4-2007-1004], (February 2, 2011), Item 1,** Operator failed to identify or evaluate in its IMP the potential for interactive threats to each covered pipeline segment. Specifically, the

	operator's procedures contained no process to ensure that multiple threats on the same pipeline were evaluated for interrelated effects. c) **El Paso Natural Gas Co., [4-2007-1007], (March 10, 2011), Item 3,** Operator failed to identify and evaluate all potential threats to each covered segment in their system. Specifically, the operator failed to consider the threats listed in Section 2 of B31.8S, and to have a threat evaluation process that comprehensively integrated available data to enable full consideration of interacting threats.
Examples of a Probable Violation or Inadequate Procedures	1. There is no process that describes the requirements for identifying and evaluating threats to covered pipeline segments. 2. The process does not describe the requirements for identifying and evaluating threats. 3. The records do not demonstrate that all of the threats required by the rule and ASME standard were considered and/or evaluated. 4. Specific threats for a particular pipeline segment were eliminated from consideration without justification. 5. The records do not demonstrate that interactive threats from different threat categories (e.g. manufacturing defects activated by pressure cycling, corrosion accelerated by third party or outside force damage) were evaluated or considered. 6. The records do not demonstrate that significant facility risk factors were considered. 7. The records do not demonstrate that industry data and experience were considered in identifying and evaluating threats. 8. The operator had experienced a failure due to construction defects (e.g., wrinkle bends), after a Subpart J test, or had knowledge of construction defects, and did not consider the threat of future failures involving construction defects. 9. Failure to fully include review of potential threats involving internal and external corrosion, (e.g. moisture content, inhibitors, cathodic protection survey results, coating condition, or prior corrosion related failures and other pipeline operating characteristics). 10. Failure to consider or rule out the possibility of SCC. 11. Failure to consider equipment failures as a potential threat. 12. Failure to consider third party damage as a potential threat. 13. Failure to consider weather or outside force as a potential threat. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Threat identification listing. 3. Review or documentation for basis or elimination of each threat. 4. GIS or other pipe data. 5. Incident reports that show failures in non-covered segments were not considered in the threat identification of covered segments (e.g., seam failures). 6. Data that shows an operator did not give sufficient weight to the existence of a threat (e.g., records showing SCC was found on pipelines, metallurgical reports showing cyclic fatigue was a contributor to failure). 7. Pipeline inspection reports. 8. Subpart J test results. 9. Other operator records that demonstrate that threat identification was inadequate. 10. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding threat identification.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.917(b)
Section Title	How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?
Existing Code Language	(b) Data gathering and integration. To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-12-06** **Verification of Records** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities to verify their records relating to operating specifications for maximum allowable operating pressure (MAOP) required by 49 CFR 192.517 and maximum operating pressure (MOP) required by 49 CFR 195.310. This Advisory Bulletin informs gas operators of anticipated changes in annual reporting requirements to document the confirmation of MAOP, how they will be required to report total mileage and mileage with adequate records, when they must report, and what PHMSA considers an adequate record. In addition, this Advisory Bulletin informs hazardous liquid operators of adequate records for the confirmation of MOP. **Advisory Bulletin ADB-11-01** **Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation.** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous

	liquid pipeline facilities of their responsibilities, under Federal integrity management (IM) regulations, to perform detailed threat and risk analyses that integrate accurate data and information from their entire pipeline system, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP), and to utilize these risk analyses in the identification of appropriate assessment methods, and preventive and mitigative measures. **Advisory Bulletin ADB-03-05** **Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines.** RSPA's Office of Pipeline Safety (OPS) is issuing this advisory notice to owners and operators of gas and hazardous liquid pipelines to consider the threat from stress corrosion cracking (SCC) when developing and implementing Integrity Management Plans. Operators should determine whether their pipelines are susceptible to SCC and assess the impact of SCC on pipeline integrity. Based on this evaluation, an operator should prioritize application of additional in-line inspection and hydrostatic testing and take actions to remediate problem areas. **Alert Notice ALN-88-01** The purpose of this letter is to advise you of recent findings relative to factors contributing to operational failures of pipelines constructed with Electric Resistance Weld (ERW) pipe manufactured prior to 1970. If you have such pipe in your pipeline system, the Office of Pipeline Safety (OPS) recommends that you read the enclosed "ALERT NOTICE: and take appropriate preventive steps.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 2.2, Appendix A. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008 Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, Final Report N0. 05-12R, John F. Kiefner, April 26, 2007. Pipe Wrinkle Integrity Determination, TTO-04, Michael Baker Jr. Inc., May 2003. Stress Corrosion Cracking Study, TTO-08, Michael Baker Jr. Inc., January 2005. Dent Study, TTO-10, Michael Baker Jr., November 2004. Pipe Wrinkle Study, TTO-11, Michael Baker Jr. Inc., October 2004. Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, TTO 5, Michael Baker Jr., April 2004. Integrity Characteristics of Vintage Pipelines, INGAA Foundation, Inc., November 2004.

	Supplemental Guidance Appendix B.02, Typical Risk Factors Associated with Pipelines. Supplemental Guidance Appendix B.03, ILI Tool Characteristics and Attributes. Supplemental Guidance Appendix B.05, Electric Resistance Welded Piping. Supplemental Guidance Appendix B.07, White Paper - Assessing for Third Party Damage. Supplemental Guidance Appendix C.01, Protocol Guidance for Identification of Threats, Data Integration, and Risk. PHMSA Gas Transmission Integrity Management FAQs: 81 What kinds of information must be integrated in performing a continual evaluation of pipeline integrity? 205 Does an operator have to provide the original source documents for the covered segment of the pipeline? (Source document means actual pressure test chart for MAOP, mill test report on pipe, etc.) In the absence of original source material, will DOT accept inventory map data for pipeline information, MAOP database information, etc.? 222 Must I consider information from portions of my pipeline not in HCAs when developing my integrity management program? 240 What must I do for "data integration"?
Guidance Information	1. Data and information must be gathered on the entire pipeline. 2. ASME B31.8S-2004, Section 4.2, requires the operator's approach to the use of data to be thoroughly documented. The data plan should address all steps in the assembly, analysis, and application of data in the operator's IM program. 3. Operators are expected to have accurate knowledge of their pipeline location / centerline. Without knowing precisely where their pipe is located, the benefits of data integration cannot be realized. Operators should be able to demonstrate how they have verified pipeline location. 4. At a minimum, an operator must gather and evaluate the set of data specified in ASME B31.8S-2004, Appendix A (summarized in ASME B31.8S-2004, Table 1) and consider the following on covered segments and similar non-covered segments: a) Past incident history b) Corrosion control records c) Continuing surveillance records d) Patrolling records e) Maintenance history f) Internal inspection records g) All other conditions specific to each pipeline. 5. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 6. Selected Final Orders Referencing §192.917(b): a) **Equitable Resources (A.K.A Equitable Gas Co.), [1-2006-1006], (May 13, 2010), Item 1A,** Equitable's IMP did not include a detailed plan for the validation of missing data. Section 192.917(b) and B31.8S set out

	requirements for addressing missing or questionable data. Equitable's procedures do not address the validation of data values that have been assumed. b) **Equitable Resources (A.K.A Equitable Gas Co.), [1-2006-1006], (May 13, 2010), Item 1C,** Equitable failed to maintain accurate pipe characteristics in its IMP. Specifically, the grade of a plastic pipeline was incorrect and the MAOP and test pressure of the line were listed as the same. Equitable argued that this had no effect on the risk of the pipeline, which was low. Although this particular inaccuracy caused no apparent harm, accurate data entry is important to the quality of Equitable's IMP. Inaccurate data can result in a failure to identify and address the actual risks on a pipeline segment. c) **Indiana Gas Co. Inc., [2-2007-1014], (July 15, 2010), Item 3B,** Operator failed to gather and integrate existing data and information on its pipeline as was required by its own procedure. d) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 9,** Operator failed to include proper procedures in its IMP for gathering and integrating data. Also, the operator failed to develop procedures to indicate the basis for assumptions made when data was missing or suspect. Specifically, the operator failed to: (1) make conservative assumptions with regard to missing threat and segment data; (2) maintain records that identified how unsubstantiated data were used; and (3) initiate or plan actions to obtain data where there were data deficiencies. e) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 10,** Operator failed to analyze and review each covered segment of its system using the complete data sets specified in Appendix A of B31.8S and the factors specified in §192.917(b). f) **Kern River Gas Transmission Co., [5-2006-1006]. (December 11, 2006), Item 1,** Operator failed to analyze all relevant information and risk factors to identify and evaluate potential threats to pipeline segments in an HCA. g) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 5B,** Operator failed to develop and implement an IMP that identified and evaluated the potential threats to its covered pipeline that could be relevant to the covered segments. Specifically, the operator failed to properly integrate the required data by the December 17, 2004 deadline. h) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 5D,** Operator failed to have a process in its IMP for verifying data quality, insofar as the company's procedures did not require conservative assumptions to be applied if certain data were missing or suspect. It was not apparent if conservative values had been applied. For example, pipeline sections containing ERW pipe defaulted to a non-conservative value without verifying that operating pressure had actually been at the MAOP. In addition, the operator failed to maintain records showing how unsubstantiated data was used and failed to specify that additional inspections or field data collection efforts were necessary if data were missing or suspect.

Examples of a Probable Violation or Inadequate Procedures	1. No process that describes the requirements to gather data. 2. Process for collecting and reviewing data was inadequate. 3. Process does not include a procedure for ensuring the accuracy and completeness of information and data used in the identification of potential threats and the risk analysis. 4. Process does not include plans for additional inspection activities or field data collection efforts as needed to ensure data completeness and accuracy. 5. There are obvious gaps where data was not integrated such as comparing third party damage against known One Call tickets and other patrols that could have potentially identified a third party damage event. 6. Operations personnel do not know to provide or integrate the data and no method exists to ensure the data and/or knowledge is incorporated into the overall integrity management program. 7. No plan for identifying gaps in data or obtaining missing data. 8. Data in Geographic Information System (GIS) or Pipeline Open Data Standard PODS is not consistent with recent data collected on the pipeline. 9. The process does not consider industry data and experience in identifying and evaluating threats. 10. Records do not demonstrate that data was gathered and evaluated as specified in Table 1 of ASME B31.8S-2004. 11. Records fail to demonstrate that the documentation required to be maintained of conditions of covered segments and similar non-covered segments were considered during data gathering. 12. Records do not demonstrate that the data sources specified in Table 2 of ASME B31.8S-2004 were utilized during data gathering. 13. Records do not demonstrate that data was checked for accuracy during data gathering and integration. 14. Records do not demonstrate that unavailable data elements were considered. 15. Records fail to demonstrate that a process to define unknown or missing data was implemented. 16. Records do not demonstrate that additional inspection actions or field data collection were implemented when warranted. 17. Records do not demonstrate that new information was incorporated in a timely and/or effective manner. 18. Records do not demonstrate that data was gathered to evaluate the susceptibility of pipeline segments to third party damage. 19. Records do not demonstrate that exclusion of a threat based on inadequate or unavailable data was justified. 20. Records do not show additional inspection or field data collection activities to improve the accuracy and completeness of the data. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Lists of source data used for integrating data. 3. Operator threat data. 4. Operator records. 5. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the data integration process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.917(c)
Section Title	How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?
Existing Code Language	(c) Risk assessment. An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-12-06** **Verification of Records** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities to verify their records relating to operating specifications for maximum allowable operating pressure (MAOP) required by 49 CFR 192.517 and maximum operating pressure (MOP) required by 49 CFR 195.310. This Advisory Bulletin informs gas operators of anticipated changes in annual reporting requirements to document the confirmation of MAOP, how they will be required to report total mileage and mileage with adequate records, when they must report, and what PHMSA considers an adequate record. In addition, this Advisory Bulletin informs hazardous liquid operators of adequate records for the confirmation of MOP. **Advisory Bulletin ADB-11-01** **Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation.** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities of their responsibilities, under Federal integrity management (IM) regulations, to perform detailed threat and risk analyses that integrate accurate data and information from their entire pipeline system, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum

	Operating Pressure (MOP), and to utilize these risk analyses in the identification of appropriate assessment methods, and preventive and mitigative measures. **Advisory Bulletin ADB-03-05** **Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines.** RSPA's Office of Pipeline Safety (OPS) is issuing this advisory notice to owners and operators of gas and hazardous liquid pipelines to consider the threat from stress corrosion cracking (SCC) when developing and implementing Integrity Management Plans. Operators should determine whether their pipelines are susceptible to SCC and assess the impact of SCC on pipeline integrity. Based on this evaluation, an operator should prioritize application of additional in-line inspection and hydrostatic testing and take actions to remediate problem areas. **Alert Notice ALN-88-01** The purpose of this letter is to advise you of recent findings relative to factors contributing to operational failures of pipelines constructed with Electric Resistance Weld (ERW) pipe manufactured prior to 1970. If you have such pipe in your pipeline system, the Office of Pipeline Safety (OPS) recommends that you read the enclosed "ALERT NOTICE: and take appropriate preventive steps.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 2.2, Appendix A. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008. Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, Final Report N0. 05-12R, John F. Kiefner, April 26, 2007. Pipe Wrinkle Integrity Determination, TTO-04, Michael Baker Jr. Inc., May 2003. Stress Corrosion Cracking Study, TTO-08, Michael Baker Jr. Inc., January 2005. Dent Study, TTO-10, Michael Baker Jr., November 2004. Pipe Wrinkle Study, TTO-11, Michael Baker Jr. Inc., October 2004. Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, TTO 5, Michael Baker Jr., April 2004. Integrity Characteristics of Vintage Pipelines, INGAA Foundation, Inc., November 2004. Supplemental Guidance Appendix B.02, Typical Risk Factors Associated with Pipelines. Supplemental Guidance Appendix C.01, Protocol Guidance for Identification of Threats, Data Integration, and Risk.

	PHMSA Gas Transmission Integrity Management FAQs: 28 What must an operator consider in prioritizing pipe segments for assessment and re-assessment? 45 Can the operator use risk assessment data to defend longer intervals between integrity assessments? 83 Will operators be expected to consider external conditions such as earthquake fault lines or mining subsidence in their integrity management program? 91 How do operators assess and control risk caused by third-parties over which they have no direct control? 102 Can operators include potential business consequences (e.g., curtailments, plant shutdown) in their risk determinations? 142 When should risk analysis be performed? 168 Does OPS expect operators to progress through the four risk analysis methods, from least complicated to most complicated as the operator moves to a performance based program? 234 How often must my risk analysis be updated?
Guidance Information	1. Risk assessment must integrate the results of the threat evaluation and data activities to produce risk results that support decisions in the operator's IM program, specifically: a) A risk-based schedule of baseline integrity assessments (FAQ-28 clarifies that the risk posed by each pipeline segment covered by the rule must be considered in scheduling baseline assessments and periodic re-assessments. Risks must be evaluated using a risk assessment that meets ASME B31.8S-2004, Section 5); b) Establish re-assessment intervals according to segment risks; c) Decisions on preventive and mitigative measures in order to achieve additional risk reduction beyond integrity assessment and repair activities. 2. ASME B31.8S-2004 includes requirements to ensure that the operator's process provides for updating the risk assessment if new information is obtained or conditions change on the pipeline segments. 3. The operator's risk assessment process must include elements for validation of results. PHMSA inspectors should use their knowledge of the operator's pipeline to validate the output of the risk model. The results need to be reviewed by knowledgeable personnel. Reviewers will compare the risk estimates for segments with their knowledge of the system and understanding of risk factors. It is possible that the risk assessment results will yield new insights, so that there may be some variance between the operator's previous understanding of risk factors and what is produced by the risk assessment 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.

	5. Selected Final Orders Referencing §192.917(c): a) **Texas Gas Transmissions, LLC, [2-2006-1004], (June 29, 2006), Item 1,** Texas Gas Transmissions failed to conduct a risk assessment that follows Section 5 of B31.8S and considers the identified threats for each covered segment; fails to use the risk assessment to prioritize the covered segments for baseline and continual reassessments; and to determine what additional preventive and mitigative measures are needed. b) **B.P. West Coast Products LLC, [2-2008-5007], (October 6, 2010), Item 7,** The operator has violated §192.917(c) by failing to have a risk model for conducting its risk assessments that enabled the operator to determine the need for preventive and mitigative measures to minimize failure consequences for covered segments. c) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 11,** Operator failed to have proper procedures in its IMP to conduct risk assessments for identifying threats to pipeline integrity. Specifically, the operator's risk assessment failed to address how risk data was used to accomplish the six specific objectives in Section 5.3 of B31.8S. d) **Centerpoint Energy Gas Transmission, [4-2007-1004], (February 11, 2011), Item 2,** Operator failed to conduct a risk assessment in accordance with Section 5 of B31.8S. Specifically, the operator did not provide documentation in its IMP to support the conclusion that the company could eliminate certain threats from its risk assessment for HCAs.
Examples of a Probable Violation or Inadequate Procedures	1. Risk assessment was not utilized for the justification of both the baseline and continual assessments. 2. Failure to include some elements from the required ASME/ANSI B31.8S-2004, Section 5 process without an acceptable technical justification for their exclusion. 3. Risk assessment did not include all of the threats identified in §192.917(a). 4. A defined logic that provides a complete, accurate, and objective analysis of risk was not included in the risk assessment. 5. The frequency and consequence of past events was not considered in the risk assessment. (ASME B31.8S-2004, Section 5) 6. The results of pipeline inspections were not integrated in the development of risk estimates in the risk assessment. (ASME B31.8S-2004, Section 5) 7. A set of weighting factors to indicate relative level of influence of each risk assessment component was not included in the risk assessment. (ASME B31.8S-2004, Section 5) 8. Pipeline segment size was not taken into account to analyze data in the risk assessment. (ASME B31.8S-2004, Section 5) 9. The risk analysis process does not require appropriately conservative assumptions to be used in situations where the risk factor data is unsubstantiated or inadequate. (ASME B31.8S-2004, Section 5) 10. Risk evaluation for BAP scheduling was inadequate or incomplete and/or did not consider each of the relevant risk factors required by the rule or standard.

	11. Failure to prioritize certain covered segments as high-risk segments even though they meet the following conditions which require them to be prioritized as high-risk segments: a. Segments that contain low frequency resistance welded (ERW) pipe or lap welded pipe that satisfy the conditions specified in ASME B31.8S-2004, Appendix A4.3 and ASME B31.8S-2004, Appendix A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years. b. Covered segments that have manufacturing or construction defects (including seam defects) where any of the following changes occurred in the covered segment: operating pressure increases above the maximum operating pressure experienced during the preceding five years; MAOP increases; or the stresses leading to cyclic fatigue increase. 12. The process does not require validation of risk analysis results. (ASME B31.8S-2004, Section 5) 13. The process does not document the requirements for completing a risk assessment validation. (ASME B31.8S-2004, Section 5) 14. The process does not require that the risk analysis is kept up to date with pipeline and facility configuration and conditions. (ASME B31.8S-2004, Section 5) 15. The process does not use leak, failure, and incident history to validate the risk model.(ASME B31.8S-2004, Section 5) 16. Records do not demonstrate that all covered segments were included in the risk analysis. 17. Records do not demonstrate that risk assessment was established to prioritize pipelines/segments for scheduling of integrity assessments and risk mitigating actions. 18. Records do not demonstrate that risk assessment was established to determine the benefit derived from mitigating actions. (ASME B31.8S-2004, Section 5) 19. Records do not demonstrate that risk assessment was established to determine the most effective risk mitigative measures for the identified threats. (ASME B31.8S-2004, Section 5) 20. Records do not demonstrate that risk assessment was established to determine the integrity impact from modified inspection intervals. (ASME B31.8S-2004, Section 5) 21. Records do not demonstrate that risk assessment was established to determine the use of or need for alternative inspection methodologies. (ASME B31.8S-2004, Section 5) 22. Records do not demonstrate that risk assessment was established to facilitate decisions to address risk along a pipeline or within a facility. (ASME B31.8S-2004, Section 2.3.3 and Section 5) 23. Records do not demonstrate that appropriate personnel were allocated to the risk assessment process. (ASME B31.8S-2004, Section 5.4)

	24. Records do not demonstrate that the leak, failure, and incident history was used to validate the risk model. (ASME B31.8S-2004, Section 5) 25. Records do not show how risk factor data that is unsubstantiated or missing is treated in the risk analysis. (ASME B31.8S-2004, Section 4.4) 26. Records do not show that appropriately conservative assumptions were used in the risk analysis when there is unsubstantiated or missing risk factor data. 27. Records do not demonstrate that a continuous validation process was implemented for risk assessment results. 28. Records do not demonstrate that the risk assessment was updated to reflect integrity assessment results or completed prevention and mitigation actions. 29. Records do not demonstrate that the risk assessment was adequately integrated into field reporting, engineering, facility mapping, or other processes as necessary to ensure regular updates. 30. Records do not demonstrate that the risk assessment was adequately revised when pipeline maintenance or other activities identified inaccuracies in the characterization of the risk for any segment. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Copy of risk assessment, as applicable. 3. Operator’s identification/categorization of threats. 4. Operator’s segment listing by risk rank. 5. Pipe material specifications indicating the use of ERW pipeline. 6. Determination of manufacturing or construction defects. 7. Operator records. 8. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the risk assessment process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.917(d)
Section Title	How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?
Existing Code Language	(d) Plastic transmission pipeline. An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB -12-03** **Notice to Operators of Driscopipe 8000 High Density Polyethylene Pipe of the Potential for Material Degradation** On March 6, 2012, PHMSA issued this advisory bulletin to alert operators using Driscopipe® 8000 High Density Polyethylene Pipe (Drisco8000) of the potential for material degradation. Degradation has been identified on pipe between one-half inch to two inches in diameter that was installed between 1978 and 1999 in desert-like environments in the southwestern United States. However, since root causes of the degradation have not been determined, PHMSA cannot say with certainty that this issue is isolated to these regions, operating environments, pipe sizes, or pipe installation dates. While the manufacturer has attempted to communicate with known or suspected users, PHMSA and the National Association of Pipeline Safety Representatives (NAPSR) have identified several operators currently using Drisco 8000 pipe who had not received communications about the issue. PHMSA is issuing this advisory bulletin to all operators of Drisco 8000 pipe in an effort to ensure they are aware of the issue, communicating with the manufacturer and their respective regulatory authorities to determine if their systems are susceptible to similar degradation, and taking measures to address it. **Advisory Bulletin ADB-11-01** **Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation.** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities of their responsibilities, under Federal integrity management (IM) regulations, to perform detailed threat and risk analyses that

	integrate accurate data and information from their entire pipeline system, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP), and to utilize these risk analyses in the identification of appropriate assessment methods, and preventive and mitigative measures.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 4 and 5 PHMSA Gas Transmission Integrity Management FAQs: 246 Section 192.901 lists the sections of Subpart O that apply to plastic transmission pipelines. Section 192.905, "How does an operator identify a high consequence area?" is not included. Do I need to define HCAs for my plastic transmission pipeline? 247 For plastic transmission pipeline, must I meet all of the requirements in the sections specified in section 192.901 or just those requirements specifically directed at plastic pipe?
Guidance Information	1. Verify that the information in ASME B31.8S-2004, Section 4 and ASME B31.8S-2004, Section 5, and any unique threats to the integrity of plastic pipe have been considered when assessing the threats to each covered segment of plastic pipeline. Some of the principal threats for plastic pipe that should be considered in the operator's risk assessment include: a) Third Party Damage b) Other Outside Force Damage (e.g., ground movement) c) Some manufacturing defects for 1970s-era plastic pipe d) Some material defects due to thermal conditions affecting material properties due to excessive cold or heat e) Some construction defects (e.g., poor joints) f) Other unique threats (e.g., worms, gophers, etc.) 2. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to address the issues identified in ASME B31.8S-2004, Sections 4 and 5. 2. Failure to evaluate the threats to its plastic pipe. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Inventory of plastic transmission pipelines in covered segments. 3. Threat identification list for plastic pipelines. 4. Operator records. 5. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the threat analysis with regards to plastic pipe.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.917(e)
Section Title	How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?
Existing Code Language	(e) Actions to address particular threats. If an operator identifies any of the following threats, the operator must take the following actions to address the threat. (1) Third party damage. An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration. (2) Cyclic fatigue. An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment. (3) Manufacturing and construction defects. If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must

	prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment. (i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years; (ii) MAOP increases; or (iii)The stresses leading to cyclic fatigue increase. (4) ERW pipe. If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment (5) Corrosion. If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non- covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-11-01** **Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation.** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities of their responsibilities, under Federal integrity management (IM) regulations, to perform detailed threat and risk analyses that integrate accurate data and information from their entire pipeline system, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP), and to utilize these risk analyses in the identification of appropriate assessment methods, and preventive and mitigative measures.

	Advisory Bulletin ADB-03-05 **Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines.** RSPA's Office of Pipeline Safety (OPS) is issuing this advisory notice to owners and operators of gas and hazardous liquid pipelines to consider the threat from stress corrosion cracking (SCC) when developing and implementing Integrity Management Plans. Operators should determine whether their pipelines are susceptible to SCC and assess the impact of SCC on pipeline integrity. Based on this evaluation, an operator should prioritize application of additional in-line inspection and hydrostatic testing and take actions to remediate problem areas. **Alert Notice ALN-88-01** The purpose of this letter is to advise you of recent findings relative to factors contributing to operational failures of pipelines constructed with Electric Resistance Weld (ERW) pipe manufactured prior to 1970. If you have such pipe in your pipeline system, the Office of Pipeline Safety (OPS) recommends that you read the enclosed "ALERT NOTICE: and take appropriate preventive steps.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 2.2, Appendix A. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008 Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, Final Report N0. 05-12R, John F. Kiefner, April 26, 2007. Pipe Wrinkle Integrity Determination, TTO-04, Michael Baker Jr. Inc., May 2003. Stress Corrosion Cracking Study, TTO-08, Michael Baker Jr. Inc., January 2005. Dent Study, TTO-10, Michael Baker Jr., November 2004. Pipe Wrinkle Study, TTO-11, Michael Baker Jr. Inc., October 2004. Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, TTO 5, Michael Baker Jr., April 2004. Integrity Characteristics of Vintage Pipelines, INGAA Foundation, Inc., November 2004. Supplemental Guidance Appendix B.02, Typical Risk Factors Associated with Pipelines. Supplemental Guidance Appendix B.05, Electric Resistance Welded Piping. Supplemental Guidance Appendix B.07, White Paper - Assessing for Third Party Damage. PHMSA Gas Transmission Integrity Management FAQs: 141 A spike test can be very useful for assessing some threats, including seam issues. Can a spike test be used as an assessment method?

	219 Are integrity assessments required for manufacturing and construction defects, including seam defects, if the pipeline has been pressure tested in accordance with Subpart J? 220 Are assessments required for manufacturing and construction defects, including seam defects, if the pipeline has not been pressure tested in accordance with Subpart J? 224 What actions must I take on non-covered segments if I find corrosion during an assessment of segments in HCA? 231 What 5-year period must I consider to establish a reference pressure for stability of manufacturing and construction defects?
Guidance Information	1. All pipelines are considered to contain manufacturing and construction defects since there is no practical way to guarantee defect-free pipe. 2. Pipelines that have experienced failures due to seam defects or other manufacturing and construction defects since its last appropriate Subpart J pressure test are considered to be susceptible to these threats. 3. ERW pipe segments susceptible to longitudinal seam failure must have been included in the operator's assessment plan and uniquely identified. 4. If an operator found corrosion on a covered pipeline segment they "must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics." 5. Periodic evaluations must consider cyclic fatigue and other loading conditions (including ground movement, suspension bridge condition) that could lead to failure of a deformation, including dent or gouge, or other defect in a covered segment. The evaluation should assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. A failure to conduct this evaluation should be cited under §192.917(e) rather than under the periodic evaluation citation of §192.937. 6. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 7. Selected Final Orders Referencing §192.917(e): a) **Equitable Resources (A.K.A Equitable Gas Co.), [1-2006-1006], (May 13, 2010), Item 2J,** Equitable violated §192.917(e)(1) by failing to address third party damage as part of its pre-assessment process. They also violated §192.925(b)(2) by failing to have a sufficiently documented process for integrating and analyzing ECDA and third party damage data or for identifying potential area of third-party damage that required remedial action. Equitable admitted that it had reviewed Line H-153 data alongside aerial alignment maps and in the field to determine the location of foreign line crossings only after the inspection. b) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 5A,** Operator failed to develop and follow procedures for identifying whether its covered segments contained low frequency ERW pipe, lap welded pipe, or other pipe that satisfied the conditions specified in B31.8S, and whether any covered or no-covered segments in its system with such pipe had experienced seam failure, or whether the operating pressure on any covered segment had increased over the maximum operating pressure experienced

	during the preceding five years. Specifically the operator did not have procedures in place to verify that the assessment method(s) it had selected for such pipe were proven to be capable of assessing seam integrity and detecting seam corrosion anomalies.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to have a process defining expected courses of actions to address the different threats identified in this regulation including Third Party Damage, Cyclic Fatigue, Manufacturing and Construction Defects, ERW Pipe, and Corrosion. 2. Failure to utilize the data integration required by paragraph (b) of this section and ASME/ANSI B31.8S-2004, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. 3. Third party damage identified as a threat, but failure to implement comprehensive additional preventive measures in accordance with §192.935. 4. Third party damage identified as a potential threat but failure to measure the effectiveness of the preventive measures. 5. Failure to use the data collected from an ILI or an external corrosion direct assessment to integrate with the other data related to encroachments or foreign line crossings to determine if additional third party damage may exist. 6. Failure to evaluate whether cyclic fatigue or other loadings could pose a threat to a covered segment. 7. The records do not demonstrate that the impact of cyclic fatigue was evaluated. 8. Failure to use the results from cyclic fatigue evaluation to evaluate the significance of this threat in prioritizing covered segments. 9. Failure to evaluate pipe to identify manufacturing and construction defects in covered segments. Considered manufacturing and construction related defects to be stable without sufficient justification. 10. Failure to consider manufacturing and construction defects as a potential threat to the pipeline. 11. Failure to evaluate the operating pressure in the five year period preceding the identification of a high consequence area in regards to manufacturing and construction threats. 12. Failure to evaluate the threats associated with ERW pipe in covered segments. 13. Failure to consider seam failures in non-covered segments when evaluating for the threat of seam failure. 14. The operator experienced a seam failure and did not select an assessment technology or technology with a proven application capable of assessing seam integrity and seam corrosion anomalies. 15. The operator classified the manufacturing and construction threat as low risk without a valid Subpart J pressure test. 16. Experienced a failure due to a seam defect(s) after a Subpart J test, and did not consider the threat of manufacturing and construction defects in the assessment. 17. The operating pressure on the covered segment has increased over the maximum operating pressure in the previous five year period and the operator

	did not select an assessment technology or technology with a proven application capable of assessing seam integrity and seam corrosion anomalies. 18. The operating pressure on the covered segment has increased over the maximum operating pressure in the previous five year period; there was an increase in MAOP; or stresses on the pipeline that could lead to cyclic fatigue and the operator did not select an assessment technology or technology with a proven application capable of assessing for manufacturing and construction defects. 19. Corrosion identified on a covered pipeline segment but did not evaluate and remediate, as necessary, all pipeline segments with similar material coating and environmental characteristics. 20. Failure to include both covered and non-covered segments that experienced corrosion in their risk program and evaluation. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Threat documentation. 3. Failure history by cause category. 4. Original construction records. 5. Leak records. 6. Operator records. 7. Pressure records. 8. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of programs to address threats addressed by §192.917(e).
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.919
Section Title	What must be in the baseline assessment plan?
Existing Code Language	An operator must include each of the following elements in its written baseline assessment plan: (a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (See §192.917.); (b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (See §192.917.) More than one method may be required to address all the threats to the covered pipeline segment; (c) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule; (d) If applicable, a direct assessment plan that meets the requirements of §§192.923, and depending on the threat to be addressed, of §192.925, §192.927, or §192.929; and (e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	
Interpretation Summaries	**Interpretation: WINDOT 192.919 1 Date: 4-10-2008** The Pipeline and Hazardous Materials Safety Administration (PHMSA) has agreed that neither current regulations nor the NACE International industry consensus standard, NACE RP0502-2002, "External Corrosion Direct Assessment Methodology," explicitly requires the use of Guided Wave Ultrasonics (GWUT) for cased piping. In addition, the following clarifications with respect to integrity assessments on cased pipelines that comply with the integrity management rules in Title 49, Part 192, Subpart O. • Operators are required to assess all pipe segments that can affect high consequence areas (HCAs), including cased piping [49 CFR 192.919(c) and 921(a)]. Though casings make up a very small percentage of the total gas transmission system, PHMSA recognizes that some cased piping segments cannot (practically) be assessed using in-line inspection (ILI) or pressure testing. Moreover, the NACE ECDA standard referenced in the Gas IMP regulation does not explicitly reference or identify any technology to assess carrier pipe inside a non-shorted casing. Other technology can be used if the operator demonstrates it can provide an equivalent understanding of the condition of the line pipe [49 CFR 192.921(a)(4)].

Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-11-01** **Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities of their responsibilities, under Federal integrity management (IM) regulations, to perform detailed threat and risk analyses that integrate accurate data and information from their entire pipeline system, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP), and to utilize these risk analyses in the identification of appropriate assessment methods, and preventive and mitigative measures. **Advisory Bulletin ADB-09-01** **Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe** PHMSA is issuing an advisory bulletin to owners and operators of natural gas pipeline and hazardous liquid pipeline systems. This bulletin advises pipeline system owners and operators of the potential for high grade line pipe installed on projects to exhibit inconsistent chemical and mechanical properties. Yield strength and tensile strength properties that do not meet the line pipe specification minimums have been reported. This advisory bulletin pertains to microalloyed high strength line pipe grades, generally Grade X-70 and above. PHMSA recently reviewed metallurgical testing results from several recent projects indicating pipe joints produced from plate or coil from the same heat may exhibit variable chemical and mechanical properties by as much as 15% lower than the strength values specified by the pipe manufacturer. **Advisory Bulletin ADB-03-07** **Guidance on When the Baseline Integrity Assessment Begins** This document provides guidance to operators of gas transmission pipelines on the requirement in 49 U.S.C. 60109 that operators begin the baseline integrity assessment of pipeline segments located in high consequence areas no later than June 17, 2004. Trade associations representing natural gas pipeline companies affected by this requirement, have asked for guidance on what actions an operator must take to begin a baseline assessment. This document provides guidance to gas transmission operators on what initial steps RSPA/OPS expects each operator to take to begin the baseline integrity assessment to meet the intent of the statute. **Advisory Bulletin ABD-04-01** **Hazards Associated with De-watering of Pipelines** PHMSA issued this advisory bulleting to owners and operators of gas and hazardous liquid pipelines to consider the hazards associated with pipeline de-watering operations. This advisory bulletin was originally issued jointly with the Department of Labor’s Occupational Safety and Health Administration. Operators

	are strongly encouraged to follow the recommended work practices and guidelines to reduce the potential for unexpected separation of temporary de-watering pipes.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 6.2 and 6.3. Gas Piping Technology Committee (GPTC) Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs, November 1, 2010 Supplemental Guidance Appendix B.01, Protocol Guidance for Baseline Assessment Plans. PHMSA Gas Transmission Integrity Management FAQs: 10 If a pipeline subject to 192 Subpart O is sold, does the new operator "inherit" integrity management plans and deadlines from the original operator? 25 Under what conditions should the Baseline Assessment Plan be modified? 34 For purposes of establishing the deadlines for completing baseline assessments, what is the date on which an assessment is considered complete? 36 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 in 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? 38 If an operator has multiple operating companies, does OPS 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 internal management practices? 39 What specificity does OPS expect for schedules in baseline assessment plans? 72 When must the Baseline Assessment Plan and Framework be completed? 73 Will OPS prepare templates for Baseline Assessment Plans or Integrity Management Program Frameworks that operators can use? 78 Does OPS expect operators to apply different risk ranking systems for lines in HCAs? 217 In Section 192.919(b), the rule states there must be an explanation of why assessment methods are chosen to assess the integrity of the line pipe. Does this mean the methods must be chosen and explained for all segments before the assessment begins, possibly by using some sort of decision tree, or does this mean that assessment methods can be explained after the assessment is complete? For example, an operator may plan on using an ILI tool for a segment but due to last minute budget restrictions must now hydrotest the segment. Will this last minute change cause a negative effect in an OPS audit even though the operator explains the reasons for the change and the reasons for the assessment method after the assessment is complete?

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<td>Guidance Information</td>
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1. Separate operating companies, managed under the same plan, may have separate BAPs, even if the integrity management activities are performed by the same entity. The BAP(s) is required to include:
a) identification of potential threats to each covered segment
b) methods selected to assess each covered segment
c) schedule for completing the integrity assessment of all covered segments;
d) if applicable, a direct assessment plan that meets the requirements of §192.923, and depending on the threat to be addressed, of §192.925, §192.927, or §192.929 (concerns or deficiencies with direct assessment should be cited under the applicable Subpart of 192; failure to reference the direct assessment plan in the CAP would be cited under §192.919; and
e) a procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.
2. An operator may choose to develop separate BAPs for specific threats where the assessment methods are different. This approach may focus resources on the highest risk threats first.
3. The baseline assessment plan and framework must have been completed by December 17, 2004. Archived copies of revised BAPs should be maintained. A failure to maintain copies of the BAP for the useful life of the pipeline should be cited under §192.947.
4. For operators not previously subject to this rule, a baseline assessment plan and written integrity management program must be developed within one year.
5. The assessments required under the original basement assessment plan must be completed by December 17, 2012. A failure to complete the baseline assessments by the deadline should be cited under§192.921(d).
6. Although assessments included under the original baseline assessment plan may be completed, newly-identified and new covered pipeline segments (a newly constructed line) must also have a baseline assessment completed within 10 years. These segments, however, may be incorporated into a reassessment schedule required under §192.937 and specified in §192.939.
7. The operator should include a review of any pipe that has experienced yielding due to lower strength than specified [Advisory Bulletin ADB-09-01].
8. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
9. Once the baseline assessments are complete, the operator must continue to maintain and document the assessment methods and schedules in their IM Program documentation.
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<td>Examples of a Probable Violation or Inadequate Procedures</td>
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1. Failure to develop a written baseline assessment plan.
2. BAP did not include all of the required elements under 192.919.
3. BAP did not include the identification of all potential threats.
4. BAP did not include the methods selected to assess the integrity of each covered segment.
5. BAP did not include a schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule.
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	6. BAP did not include a direct assessment plan. (if applicable) 7. BAP did not include a procedure to ensure that the baseline assessment was conducted in a manner that minimizes environmental and safety risks. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Baseline assessment plan(s), any revisions, and/or assessment schedules. 3. Covered segment risk rankings for comparison with BAP prioritization of assessments. 4. Environmental and safety procedures. 5. Records. 6. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding development or implementation of the BAP.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.921(a)
Section Title	How is the baseline assessment to be conducted?
Existing Code Language	(a) Assessment methods. An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See §192.917). (1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment. (2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939 (3) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929; (4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-03-07** **Guidance on When the Baseline Integrity Assessment Begins** This document provides guidance to operators of gas transmission pipelines on the requirement in 49 U.S.C. 60109 that operators begin the baseline integrity assessment of pipeline segments located in high consequence areas no later than

	June 17, 2004. Trade associations representing natural gas pipeline companies affected by this requirement, have asked for guidance on what actions an operator must take to begin a baseline assessment. This document provides guidance to gas transmission operators on what initial steps RSPA/OPS expects each operator to take to begin the baseline integrity assessment to meet the intent of the statute.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008 Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, April 2007 Stress Corrosion Cracking Study with Database, Final Report, Michael Baker Jr., Inc., January 2005 TTO-10, Dent Study, Final Report, Michael Baker Jr., Inc., November 2004 TTO-11, Pipe Wrinkle Study Final Report, Michael Baker Jr., Inc., October 2004 TTO-05, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Final Report, Michael Baker Jr., Inc., April 2004 Use of MFL Tools to Detect Hard Spots, Duckworth and Eiber, June 2004. ANSI ASC Z380 Gas Piping Technology Committee (GPTC) NACE RP 0102-2002, In Line Inspection of Pipelines (not incorporated by reference). NACE SP 0502-2008, Pipeline External Corrosion Direct Assessment Methodology (incorporated by reference). NACE SP 0206-2006, Internal Corrosion Direct Assessment (not incorporated by reference). NACE RP 0204-2004, Stress Corrosion Cracking Direct Assessment (not incorporated by reference). Supplemental Guidance Appendix B.01, Protocol Guidance for Baseline Assessment Plans. Supplemental Guidance Appendix B.03, ILI Tool Characteristics and Attributes. Supplemental Guidance Appendix B.04, Typical Tool Selection Factors. Supplemental Guidance Appendix B.06, Hydrostatic Testing. Supplemental Guidance Appendix B.08, White Paper - Manufacturing and Construction Defects. Supplemental Guidance Appendix C.04, Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects.

	PHMSA Gas Transmission Integrity Management FAQs: 7 Do the requirements of the rule apply to "idle" pipe? 10 If a pipeline subject to 192 Subpart O is sold, does the new operator "inherit" integrity management plans and deadlines from the original operator? 34 For purposes of establishing the deadlines for completing baseline assessments, what is the date on which an assessment is considered complete? 36 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 in 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? 39 What specificity does OPS expect for schedules in baseline assessment plans? 55 A reduction in operating pressure can provide an equivalent level of safety as that provided by a Subpart J pressure test. Is a pressure reduction an acceptable integrity assessment method? 78 Does OPS expect operators to apply different risk ranking systems for lines in HCAs? 109 Section 192.921(a)(2) requires that pressure tests performed to satisfy rule assessment requirements must be conducted in accordance with subpart J. ASME/ASNI B31.8S, section 6.3 states that the details for conducting pressure tests are in ASME B31.8. These two documents contain different requirements for conducting pressure tests. Which document should take precedence? 141 A spike test can be very useful for assessing some threats, including seam issues. Can a spike test be used as an assessment method? 198 If Guided Wave UT is used as part of the ECDA process, is it considered "other technology" requiring notification to OPS/states? 235 If Guided Wave UT is used as part of the ICDA process, is it considered "other technology" requiring notification to OPS/states?
Guidance Information	1. Each covered segment of pipeline must have a defined method of assessment suitable for the identified threats. More than one method and/or tool may be required to address all the threats in a pipeline segment. 2. Based on the priorities determined by risk assessment, the operator shall conduct integrity assessments using the appropriate integrity assessment method(s). The primary integrity assessment methods that can be used are in-line inspection, pressure testing, direct assessment or other methodologies provided in Section 6.5 of ASME B31.8S-2004. The integrity assessment method is based on the threats to which the segment is susceptible. 3. A comprehensive ILI assessment program will typically consist of multiple tool runs designed to assess potential risks to pipeline segments. This may involve using geometry (deformation) tools, metal loss tools and, if indicated by crack history or significant risk factors associated with cracks or crack-like defects, crack tools.

	4. Pressure tests must be conducted in accordance with Subpart J. An operator must use the test pressures specified in Table 3 of section 5 of ASME B31.8S-2004, to justify an extended reassessment interval in accordance with §192.939. 5. A “spike” test can be conducted as part of a Subpart J test, but it cannot be used as a stand alone assessment. If used as a stand alone assessment, it requires notification to PHMSA as “other” technology. 6. Operator must follow the baseline assessment, or re-assessment, schedule defined in the Integrity Management Plan with adjustments for actual findings from previous assessments. 7. Idle lines with HCAs must be in the BAP. 8. Operator’s prioritization process must include consideration for the particular threats of ERW or lap welded pipe, and have reviewed appropriate operating data for consideration of manufacturing and construction threats. 9. An operator may choose to utilize “other technology” methods with the required notification to PHMSA. A failure to submit a notification 180 days prior to the use of "other technology" should be cited under §192.921(c)(4). 10. Plastic transmission line covered segments must be included in the BAP. 11. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 12. Selected Final Orders Referencing §192.921(a): a) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 14,** Operator’s BAP failed to select an assessment method or methods best suited to address the threats identified in particular covered segments. Specifically, the operator failed to use a caliper run to address potential third-party damage which was identified as a primary threat.
Examples of a Probable Violation or Inadequate Procedures	1. Criteria used to select the appropriate assessment method(s) was not defined or documented. 2. Inadequate process for the assessment method selection process. 3. Process did not include ASME B31.8S-2004, Section 6.2 for selecting the appropriate assessment method. 4. A spike test was used as a stand alone assessment without notification to PHMSA. 5. Direct assessment was used to assess for threats other than corrosion. 6. Failure to identify assessment method for each threat for a covered segment. 7. ILI tool selection not consistent with requirements of ASME/ANSI B31.8S-2004, section 6.2. 8. Pressure tests were not required to meet Subpart J requirements. 9. Records do not demonstrate that pressure tests met Subpart J requirements. 10. PHMSA/Regulatory notification not required to be submitted when using "other technology. 11. PHMSA/Regulatory notification was not submitted when using "other technology. 12. Technical justifications for the assessment method(s) chosen, or explanation of how selection criteria were applied to choose the assessment method(s) was not documented 13. Selected method(s) for pipe that is susceptible to SCC were not appropriate.

	14. Assessment methods other than those specified in the BAP were used without justification. 15. Assessment method(s) selected for covered segments in plastic pipe were not appropriate. 16. Assessment methods did not address the threats required by 192.917(e). *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Applicable O&M procedures. 3. PHMSA notifications for “other technology.” 4. Technical justification for assessment methods. 5. Direct assessment plan(s). 6. Pressure test records. 7. Records. 8. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding development or implementation of the BAP.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.921(b)
Section Title	How is the baseline assessment to be conducted?
Existing Code Language	(b) Prioritizing segments. An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, April 2007 Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008 Stress Corrosion Cracking Study with Database, Final Report, Michael Baker Jr., Inc., January 2005 TTO-10, Dent Study, Final Report, Michael Baker Jr., Inc., November 2004 TTO-11, Pipe Wrinkle Study Final Report, Michael Baker Jr., Inc., October 2004 TTO-05, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Final Report, Michael Baker Jr., Inc., April 2004 Use of MFL Tools to Detect Hard Spots, Duckworth and Eiber, June 2004. ANSI ASC Z380 Gas Piping Technology Committee (GPTC) Supplemental Guidance Appendix B.01, Protocol Guidance for Baseline Assessment Plans. Supplemental Guidance Appendix B.04, Typical Tool Selection Factors. Supplemental Guidance Appendix B.06, Hydrostatic Testing.

Supplemental Guidance Appendix B.08, White Paper - Manufacturing and Construction Defects.

Supplemental Guidance Appendix C.04, Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects.

PHMSA Gas Transmission Integrity Management FAQs:

10	If a pipeline subject to 192 Subpart O is sold, does the new operator "inherit" integrity management plans and deadlines from the original operator?
26	When must baseline assessments be completed?
34	For purposes of establishing the deadlines for completing baseline assessments, what is the date on which an assessment is considered complete?
36	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 in 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?
38	If an operator has multiple operating companies, does OPS 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 internal management practices?
39	What specificity does OPS expect for schedules in baseline assessment plans?
78	Does OPS expect operators to apply different risk ranking systems for lines in HCAs?
110	When the operator has identified a "new" HCA that results in the designation of additional covered segments, not previously identified as covered segments, subpart 192.905(c) requires the operator to incorporate these segments into the baseline assessment plan within one year. Subpart 192.921(f) requires the operator to complete the baseline assessment on these newly identified covered segments within ten (10) years from the date the new area is identified. Is the operator required to re-prioritize the baseline assessment plan segments per 192.921(b) each time a new segment is added even though the rule specifies a ten (10) year assessment schedule for these additional segments?
125	Can risk ranking be done by piggable sections, since that is the way my assessments will be conducted?
220	Are assessments required for manufacturing and construction defects, including seam defects, if the pipeline has not been pressure tested in accordance with Subpart J?
221	Relative to the requirement in 192.917(e)(3)(i), how much pressure increase (above the maximum experienced in the preceding five years of operation) will trigger the requirement to treat the segment as high risk for purposes of integrity assessments.

Guidance Information	1. Covered segments on idle lines should be included in BAP. 2. Baseline assessments must be done according to the BAP, although intervals may be modified according to findings. 3. The BAP must properly account for all risk factors that reflect the risk conditions on the pipeline segment. Segments containing low frequency resistance welded pipe or lap welded pipe should have been prioritized as high-risk segments in accordance with 192.917(e)(4). 4. Covered segments that meet the requirements of 192.917(e)(3)(i), (ii), and (iii) and 192.917(e)(4) must be prioritized as a high risk segment. The failure to prioritize these segments as high risk should be cited under §192.921(b). 5. If risk evaluation for BAP scheduling was inadequate or incomplete and/or did not consider each of the relevant risk factors required by the rule/standard, the concern should be cited under §192.917(e). 6. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. Segments specified in the rule as "high-risk" [i.e., per 192.917(e)(3) and (e)(4)] were not prioritized. 2. All covered segments were not prioritized in the BAP. 3. The prioritization of covered segments did not take risk rankings into account. 4. BAP was not prioritized based on all threats to the covered segment. 5. Idle lines not included in prioritization. 6. Completion of baseline assessments was not adequately documented. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. O&M procedures. 3. Covered segment risk rankings. 4. Segment identification listing. 5. Threat assessment identification. 6. Records. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the BAP prioritization process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.921(c)
Section Title	How is the baseline assessment to be conducted?
Existing Code Language	(c) Assessment for particular threats. In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, April 2007 Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008 Stress Corrosion Cracking Study with Database, Final Report, Michael Baker Jr., Inc., January 2005 TTO-10, Dent Study, Final Report, Michael Baker Jr., Inc., November 2004 TTO-11, Pipe Wrinkle Study Final Report, Michael Baker Jr., Inc., October 2004 TTO-05, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Final Report, Michael Baker Jr., Inc., April 2004 Use of MFL Tools to Detect Hard Spots, Duckworth and Eiber, June 2004. ANSI ASC Z380 Gas Piping Technology Committee (GPTC) Supplemental Guidance Appendix B.01, Protocol Guidance for Baseline Assessment Plans. Supplemental Guidance Appendix B.04, Typical Tool Selection Factors. Supplemental Guidance Appendix B.06, Hydrostatic Testing.

	Supplemental Guidance Appendix B.08, White Paper - Manufacturing and Construction Defects. Supplemental Guidance Appendix C.04, Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects. PHMSA Gas Transmission Integrity Management FAQs: 39 What specificity does OPS expect for schedules in baseline assessment plans? 46 What are acceptable integrity assessment methods? 48 What kind of tool can an operator use to conduct integrity assessments by internal inspection? 49 What type of pressure test can be used to assess pipeline integrity? 78 Does OPS expect operators to apply different risk ranking systems for lines in HCAs? 141 A spike test can be very useful for assessing some threats, including seam issues. Can a spike test be used as an assessment method? 169 Where the rule specifies certain segments with specific threats as "high risk segments," do these segments need to be in the top 50%? 198 If Guided Wave UT is used as part of the ECDA process, is it considered "other technology" requiring notification to OPS/states? 217 In Section 192.919(b), the rule states there must be an explanation of why assessment methods are chosen to assess the integrity of the line pipe. Does this mean the methods must be chosen and explained for all segments before the assessment begins, possibly by using some sort of decision tree, or does this mean that assessment methods can be explained after the assessment is complete? For example, an operator may plan on using an ILI tool for a segment but due to last minute budget restrictions must now hydrotest the segment. Will this last minute change cause a negative effect in an OPS audit even though the operator explains the reasons for the change and the reasons for the assessment method after the assessment is complete? 219 Are integrity assessments required for manufacturing and construction defects, including seam defects, if the pipeline has been pressure tested in accordance with Subpart J? 220 Are assessments required for manufacturing and construction defects, including seam defects, if the pipeline has not been pressure tested in accordance with Subpart J? 221 Relative to the requirement in 192.917(e)(3)(i), how much pressure increase (above the maximum experienced in the preceding five years of operation) will trigger the requirement to treat the segment as high risk for purposes of integrity assessments? 235 If Guided Wave UT is used as part of the ICDA process, is it considered "other technology" requiring notification to OPS/states?

Guidance Information	1. Covered segments meeting the following conditions should be prioritized as high-risk segments in the BAP: a) Segments that contain low frequency resistance welded (ERW) pipe or lap welded pipe that satisfy the conditions specified in ASME B31.8S-2004, Appendix A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years. b) Covered segments that have manufacturing or construction defects (including seam defects) where any of the following changes occurred in the covered segment: operating pressure increases above the maximum operating pressure experienced during the preceding five years; MAOP increases; or the stresses leading to cyclic fatigue increase. c) A failure to identify segments meeting these conditions in the risk assessment should be cited under §192.917(c). d) A failure to identify segments meeting these condition as high risk in the BAP should be cited under §192.921(c). 2. Operator must identify assessment method for each threat for a covered segment, and assessment method must be suitable for the threats. 3. Process should include ASME B31.8S-2004 Section 6.2 for selecting the appropriate assessment method. 4. If operator uses a pressure test as an assessment method, the process must meet Subpart J requirements. 5. A “spike” test can be conducted as part of a Subpart J test, but it cannot be used as a stand alone assessment. If used as a stand alone assessment, it requires notification of PHMSA as “other” technology. 6. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. Records do not demonstrate that selected assessment method(s) were appropriate for the segment-specific threats. 2. Selected method(s) for pipe that is susceptible to manufacturing or construction defects (including low frequency electric resistance welded pipe or lap welded pipe) were not appropriate. 3. Assessment method was not suitable for the threats. 4. Technical justification for the assessment method(s) chosen, or explanation of how selection criteria were applied to choose the assessment method(s), was not documented. 5. Selected method(s) for pipe that is susceptible to SCC were not appropriate. 6. Criteria used to select the appropriate assessment method(s) were not documented. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Applicable O&M procedures. 3. Technical justifications for assessment method selection. 4. Selection criteria for assessment methods. 5. Pipeline specifications documents pipeline threats. 6. Records. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the BAP process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.921(d)
Section Title	How is the baseline assessment to be conducted?
Existing Code Language	(d) Time period. An operator must prioritize all the covered segments for assessment in accordance with §192.917 and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, April 2007 Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008 Stress Corrosion Cracking Study with Database, Final Report, Michael Baker Jr., Inc., January 2005 TTO-10, Dent Study, Final Report, Michael Baker Jr., Inc., November 2004 TTO-11, Pipe Wrinkle Study Final Report, Michael Baker Jr., Inc., October 2004 TTO-05, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Final Report, Michael Baker Jr., Inc., April 2004 Use of MFL Tools to Detect Hard Spots, Duckworth and Eiber, June 2004. ANSI ASC Z380 Gas Piping Technology Committee (GPTC) Supplemental Guidance Appendix B.01, Protocol Guidance for Baseline Assessment Plans.

	Supplemental Guidance Appendix B.04, Typical Tool Selection Factors. Supplemental Guidance Appendix B.06, Hydrostatic Testing. Supplemental Guidance Appendix B.08, White Paper - Manufacturing and Construction Defects. Supplemental Guidance Appendix C.04, Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects. PHMSA Gas Transmission Integrity Management FAQs: 10 If a pipeline subject to 192 Subpart O is sold, does the new operator "inherit" integrity management plans and deadlines from the original operator? 26 When must baseline assessments be completed? 34 For purposes of establishing the deadlines for completing baseline assessments, what is the date on which an assessment is considered complete? 36 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 in 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? 39 What specificity does OPS expect for schedules in baseline assessment plans? 237 When must the baseline assessment be completed for piping installed after the effective date of the rule?
Guidance Information	1. BAP should have specified that 50% of high risk pipelines were assessed by December 17, 2007. 2. Operator should have documentation to demonstrate that 50% of high risk segments were assessed by December 17, 2007. 3. BAP should have specified that all baseline assessments were completed by December 17, 2012. 4. Operator should have documentation to demonstrate that all baseline assessments were completed by December 17, 2012. 5. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. A baseline assessment of 50% of high risk segments was not completed by December 17, 2007. 2. A baseline assessment of all segments was not completed by December 17, 2012. 3. Documentation does not demonstrate the completion of integrity assessments. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Baseline assessment or re-assessment schedule. 3. Baseline and re-assessment results. 4. Records. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the BAP.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.921(e)
Section Title	How is the baseline assessment to be conducted?
Existing Code Language	(e) Prior assessment. An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-03-07** **Guidance on When the Baseline Integrity Assessment Begins** This document provides guidance to operators of gas transmission pipelines on the requirement in 49 U.S.C. 60109 that operators begin the baseline integrity assessment of pipeline segments located in high consequence areas no later than June 17, 2004. Trade associations representing natural gas pipeline companies affected by this requirement, have asked for guidance on what actions an operator must take to begin a baseline assessment. This document provides guidance to gas transmission operators on what initial steps RSPA/OPS expects each operator to take to begin the baseline integrity assessment to meet the intent of the statute.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, April 2007 Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008 Stress Corrosion Cracking Study with Database, Final Report, Michael Baker Jr., Inc., January 2005

	TTO-10, Dent Study, Final Report, Michael Baker Jr., Inc., November 2004 TTO-11, Pipe Wrinkle Study Final Report, Michael Baker Jr., Inc., October 2004 TTO-05, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Final Report, Michael Baker Jr., Inc., April 2004 Use of MFL Tools to Detect Hard Spots, Duckworth and Eiber, June 2004. ANSI ASC Z380 Gas Piping Technology Committee (GPTC) Supplemental Guidance Appendix B.01, Protocol Guidance for Baseline Assessment Plans. Supplemental Guidance Appendix B.04, Typical Tool Selection Factors. Supplemental Guidance Appendix B.06, Hydrostatic Testing. Supplemental Guidance Appendix B.08, White Paper - Manufacturing and Construction Defects. Supplemental Guidance Appendix C.04, Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects. PHMSA Gas Transmission Integrity Management FAQs: 29 Can operators count prior assessments of low-risk segments used as baselines against the requirement to complete 50% of their covered mileage by December 17, 2007? 34 For purposes of establishing the deadlines for completing baseline assessments, what is the date on which an assessment is considered complete? 161 Can prior assessments be relied upon to meet the requirement that operators begin assessment activities by June 17, 2004?
Guidance Information	1. The date on which an assessment is considered complete will be the date on which the last ILI tool is removed from the pipe or for hydro-tests when final field activities related to that assessment are performed, not including repair activities. (FAQ 34) 2. The failure to reassess a covered segment according to §192.937 or §192.939 that credited a prior assessment should be cited under the applicable §192.937 or §192.939 paragraph. 3. A prior assessment may be credited as a baseline assessment if it meets the requirements of Subpart O and remedial actions have been taken to address conditions listed in §192.933. The preamble to the Federal Register Notice clarifies that reassessment of a covered segment that credited a prior assessment must be completed no later than December 17, 2009. A failure to complete the reassessment by the deadline should be cited under §192.937(a) (Federal Register / Vol. 68, No. 240 / Monday, December 15, 2003 / Rules and Regulations at Page 69805.) 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.

Examples of a Probable Violation or Inadequate Procedures	1. Criteria used to justify the use of prior assessments were not defined. 2. A prior integrity assessment was credited as a baseline assessment that did not meet the baseline requirements in this subpart. 3. Failure to conduct necessary remedial actions on pipe segments that had a prior assessment. 4. A prior integrity assessment was used as allowed but did not conduct a reassessment by December 17, 2009 in accordance with 192.937 and 192.939. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Prior baseline assessment records. 3. Reassessment records. 4. Documentation of categorization of defects from prior assessment. 5. Documentation of remedial action taken on defects identified in prior assessment. 6. Records. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding the crediting of prior assessments.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.921(f)
Section Title	How is the baseline assessment to be conducted?
Existing Code Language	(f) Newly identified areas. When an operator identifies a new high consequence area (see §192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, April 2007 Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008 Stress Corrosion Cracking Study with Database, Final Report, Michael Baker Jr., Inc., January 2005 TTO-10, Dent Study, Final Report, Michael Baker Jr., Inc., November 2004 TTO-11, Pipe Wrinkle Study Final Report, Michael Baker Jr., Inc., October 2004 TTO-05, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Final Report, Michael Baker Jr., Inc., April 2004 Use of MFL Tools to Detect Hard Spots, Duckworth and Eiber, June 2004. ANSI ASC Z380 Gas Piping Technology Committee (GPTC) Supplemental Guidance Appendix B.01, Protocol Guidance for Baseline Assessment Plans. Supplemental Guidance Appendix B.04, Typical Tool Selection Factors.

	Supplemental Guidance Appendix B.06, Hydrostatic Testing. Supplemental Guidance Appendix B.08, White Paper - Manufacturing and Construction Defects. Supplemental Guidance Appendix C.04, Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects. PHMSA Gas Transmission Integrity Management FAQs: 10 If a pipeline subject to 192 Subpart O is sold, does the new operator "inherit" integrity management plans and deadlines from the original operator? 25 Under what conditions should the Baseline Assessment Plan be modified? 34 For purposes of establishing the deadlines for completing baseline assessments, what is the date on which an assessment is considered complete? 36 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 in 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? 39 What specificity does OPS expect for schedules in baseline assessment plans? 110 When the operator has identified a "new" HCA that results in the designation of additional covered segments, not previously identified as covered segments, subpart 192.905(c) requires the operator to incorporate these segments into the baseline assessment plan within one year. Subpart 192.921(f) requires the operator to complete the baseline assessment on these newly identified covered segments within ten (10) years from the date the new area is identified. Is the operator required to re-prioritize the baseline assessment plan segments per 192.921(b) each time a new segment is added even though the rule specifies a ten (10) year assessment schedule for these additional segments? 179 How long does an operator that has had no HCAs, and therefore no integrity management program, have to develop an integrity management program after it discovers a new HCA? 237 When must the baseline assessment be completed for piping installed after the effective date of the rule?
Guidance Information	1. The BAP must be updated within one year to include newly identified HCAs. A failure to include a newly identified HCA in the BAP within one year should be cited under §192.905(c). 2. Newly identified HCAs must be scheduled for a baseline assessment date within 10 years of identification; however, this does not extend the re-assessment interval of other covered segments in the pipeline. 3. HCAs omitted or missed by an operator during the development of their BAP are not considered newly identified HCAs. 4. Failure to have procedures to address this Integrity Management element should

	be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. HCAs missed during initial identification are listed as new HCAs. 2. A baseline assessment of the line pipe in a newly identified HCA was not performed or scheduled for completion within 10 years. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Segment identification. 3. Identification of new HCA's. 4. BAP or re-assessment schedule. 5. Records. 6. Documented conversations with operator or contractor personnel. 7. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 8. Documented conversations with operator or contractor personnel identifying inconsistencies or problems assessment of newly identified HCAs.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.921(g)
Section Title	How is the baseline assessment to be conducted?
Existing Code Language	(g) Newly installed pipe. An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, April 2007 Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008 Stress Corrosion Cracking Study with Database, Final Report, Michael Baker Jr., Inc., January 2005 TTO-10, Dent Study, Final Report, Michael Baker Jr., Inc., November 2004 TTO-11, Pipe Wrinkle Study Final Report, Michael Baker Jr., Inc., October 2004 TTO-05, Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Final Report, Michael Baker Jr., Inc., April 2004 Use of MFL Tools to Detect Hard Spots, Duckworth and Eiber, June 2004. ANSI ASC Z380 Gas Piping Technology Committee (GPTC) Supplemental Guidance Appendix B.01, Protocol Guidance for Baseline Assessment Plans. Supplemental Guidance Appendix B.04, Typical Tool Selection Factors.

	Supplemental Guidance Appendix B.06, Hydrostatic Testing. Supplemental Guidance Appendix B.08, White Paper - Manufacturing and Construction Defects. Supplemental Guidance Appendix C.04, Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects. PHMSA Gas Transmission Integrity Management FAQs: 10 If a pipeline subject to 192 Subpart O is sold, does the new operator "inherit" integrity management plans and deadlines from the original operator? 25 Under what conditions should the Baseline Assessment Plan be modified? 34 For purposes of establishing the deadlines for completing baseline assessments, what is the date on which an assessment is considered complete? 36 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 in 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? 39 What specificity does OPS expect for schedules in baseline assessment plans? 110 When the operator has identified a "new" HCA that results in the designation of additional covered segments, not previously identified as covered segments, subpart 192.905(c) requires the operator to incorporate these segments into the baseline assessment plan within one year. Subpart 192.921(f) requires the operator to complete the baseline assessment on these newly identified covered segments within ten (10) years from the date the new area is identified. Is the operator required to re-prioritize the baseline assessment plan segments per 192.921(b) each time a new segment is added even though the rule specifies a ten (10) year assessment schedule for these additional segments? 179 How long does an operator that has had no HCAs, and therefore no integrity management program, have to develop an integrity management program after it discovers a new HCA? 237 When must the baseline assessment be completed for piping installed after the effective date of the rule?
Guidance Information	1. Any gas transmission pipeline placed into service after the effective date of the integrity management rule, February 14, 2004, is considered "newly installed" for purposes of the rule. Newly installed pipe includes replacement pipe. Pipe replaced in a covered segment may be credited as a completed assessment, if the pipe has been pressure tested to Subpart J. Newly constructed segments that are determined to be covered by this rule must be incorporated into the BAP with one year from when the date of their installation. This should be enforced against 192.905(c). 2. The operator should have a documented process whereby pipeline and HCA changes are controlled and documented and the organization responsible for

	developing and maintaining the Baseline Assessment Plan is notified and the changes appropriately reflected in the BAP. Any modifications or changes to the BAP, and the reasons for the modifications, must be documented before they are implemented. 3. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. Baseline assessments of newly installed pipe were not performed within 10 years. (Note: Newly installed pipe is usually pressure tested before being placed into service. This qualifies as a baseline assessment if Subpart J is met.) *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Applicable O&M procedures. 3. Pressure testing records. 4. New construction records. 5. BAP. 6. Covered segment identification. 7. Threat assessment results. 8. Records. 9. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding assessment of newly installed piping.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.921(h)
Section Title	How is the baseline assessment to be conducted?
Existing Code Language	(h) Plastic transmission pipeline. If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third- party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917 The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB -12-03** **Notice to Operators of Driscopipe 8000 High Density Polyethylene Pipe of the Potential for Material Degradation** On March 6, 2012, PHMSA issued this advisory bulletin to alert operators using Driscopipe® 8000 High Density Polyethylene Pipe (Drisco8000) of the potential for material degradation. Degradation has been identified on pipe between one-half inch to two inches in diameter that was installed between 1978 and 1999 in desert-like environments in the southwestern United States. However, since root causes of the degradation have not been determined, PHMSA cannot say with certainty that this issue is isolated to these regions, operating environments, pipe sizes, or pipe installation dates. While the manufacturer has attempted to communicate with known or suspected users, PHMSA and the National Association of Pipeline Safety Representatives (NAPSR) have identified several operators currently using Drisco 8000 pipe who had not received communications about the issue. PHMSA is issuing this advisory bulletin to all operators of Drisco 8000 pipe in an effort to ensure they are aware of the issue, communicating with the manufacturer and their respective regulatory authorities to determine if their systems are susceptible to similar degradation, and taking measures to address it. **Advisory Bulletin ADB-11-01** **Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous

	liquid pipeline facilities of their responsibilities, under Federal integrity management (IM) regulations, to perform detailed threat and risk analyses that integrate accurate data and information from their entire pipeline system, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP), and to utilize these risk analyses in the identification of appropriate assessment methods, and preventive and mitigative measures. **Advisory Bulletin ADB-99-02** **Potential Failures Due to Brittle-Like Cracking of Older Plastic Pipe in Natural Gas Distribution Systems.** PHMSA is issuing this advisory bulletin to owners and operators of natural gas distribution systems to inform them of the potential vulnerability of older plastic gas distribution pipe to brittle-like cracking. The National Transportation Safety Board (NTSB) recently issued a Special Investigation Report (NTSB/SIR-98/01), Brittle-like Cracking in Plastic Pipe for Gas Service, that described how plastic pipe installed in natural gas distribution systems from the 1960s through the early 1980s may be vulnerable to brittle-like cracking resulting in gas leakage and potential hazards to the public and property. PHMSA has also issued an additional advisory bulletin (ADB-99-01) reminding natural gas distribution system operators of the potential poor resistance to brittle-like cracking of certain polyethylene pipe manufactured by Century Utility Products, Inc.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, April 2007 ANSI ASC Z380 Gas Piping Technology Committee (GPTC) Supplemental Guidance Appendix B.01, Protocol Guidance for Baseline Assessment Plans. Supplemental Guidance Appendix B.04, Typical Tool Selection Factors. Supplemental Guidance Appendix B.08, White Paper - Manufacturing and Construction Defects. Supplemental Guidance Appendix C.04, Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects. PHMSA Gas Transmission Integrity Management FAQs: 246 Section 192.901 lists the sections of Subpart O that apply to plastic transmission pipelines. Section 192.905, "How does an operator identify a high consequence area?" is not included. Do I need to define HCAs for my plastic transmission pipeline? 247 For plastic transmission pipeline, must I meet all of the requirements in the sections specified in section 192.901 or just those requirements specifically directed at plastic pipe?

Guidance Information	1. The assessment method selected for plastic pipe should address the threats identified in the analysis conducted under §192.917(d). The guidance in ASME B31.8S-2004, Sections 4 and 5 should be used to verify that the assessment method is appropriate. 2. Concerns identified with the threat analysis for plastic pipe should be cited under §192.917(d) rather than §192.921(h). Concerns with the assessment method selected for plastic pipe would be cited under §192.921(h). 3. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 4. Integrity assessment of plastic pipe is required for threats other than third party damage. Threats other than third party damage that may be considered for assessment include: a) Other Outside Force Damage (e.g., ground movement) b) Some manufacturing defects for 1970s-era plastic pipe c) Materials defects producing cold-weather brittle conditions for plastic pipe d) Construction defects (e.g., poor joints)
Examples of a Probable Violation or Inadequate Procedures	1. Assessment method(s), for threats other than third party damage, was not determined for plastic pipeline. 2. Assessment method(s) was not justified for plastic pipeline. 3. Failure to include plastic pipe in baseline plan *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Annual reports indicating use of plastic pipe. 3. Threat assessment for plastic pipe. 4. Records. 5. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding assessment of plastic piping.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.923
Section Title	How is direct assessment used and for what threats?
Existing Code Language	(a) General. An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (ECDA), internal corrosion (ICDA), and stress corrosion cracking (SCCDA). (b) Primary method. An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in-- (1) ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4; NACE SP0502-2008 (incorporated by reference, see §192.7); and §192.925 if addressing external corrosion (ECDA). (2) ASME/ANSI B31.8S, section 6.4 and appendix B2, and §192.927 if addressing internal corrosion (ICDA). (3) ASME/ANSI B31.8S, appendix A3, and §192.929 if addressing stress corrosion cracking (SCCDA). (c) Supplemental method. An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in §192.931.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 74 FR 48593, August 11, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 6.4, Appendix A3, and Appendix B2. Gas Piping Technology Committee (GPTC)
Guidance Information	1. Not all operators will need to prepare a Direct Assessment (DA) plan. Only those operators choosing to use DA will need to prepare a written DA plan. 2. The operator's plan should include information (written justification) as to why specific DA methods (ECDA, ICDA, SCCDA) were or were not used for their integrity management program.

	3. DA plans will vary in length and complexity depending upon an operator's size, locale, policies, and amount of pipeline to be assessed. An operator may choose to have a single DA plan for all, or a separate DA plan for each, of the three corrosion threats: external, internal, and stress corrosion cracking. 4. Deficiencies with ECDA plans and implementation should be cited under §192.925. 5. Deficiencies with ICDA plans and implementation should be cited under §192.927. 6. Deficiencies with SCCDA plans and implementation should be cited under §192.929. 7. Deficiencies with confirmatory direct assessment plans and implementation should be cited under §192.931. 8. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. Use of direct assessment as a assessment method without a direct assessment plan. 2. Use of direct assessment as a primary assessment method for a threat other than external or internal corrosion or SCC. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Written direct assessment plan. 3. Evaluation and determination of threats/risks for affected pipelines. 4. Records. 5. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the direct assessment process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.925(a) & (b)
Section Title	What are the requirements for using External Corrosion Direct Assessment (ECDA)?
Existing Code Language	(a) *Definition.* ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline. (b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4, and in NACE SP0502-2008 (incorporated by reference, see §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1).
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 74 FR 48593, August 11, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 6.4. NACE SP0502-2008, Pipeline External Corrosion Direct Assessment Methodology. GTI External Corrosion Direct Assessment (ECDA) Implementation Protocol. Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs, November 1, 2010 Supplemental Guidance Appendix B.07, White Paper, Assessing for Third Party Damage. Supplemental Guidance Appendix D.01, External Corrosion Direct Assessment on problematic Areas.

	Supplemental Guidance Appendix D.02, External Corrosion Direct Assessment Excavation Location Selection. Supplemental Guidance Appendix G.01, Calculating Re-Assessment Interval. PHMSA Gas Transmission Integrity Management FAQs: 155 In several places, the rule requires that operators follow Appendices in ASME/ANSI B31.8S. The title of both Appendices A and B in the standard indicate they are non-mandatory. Must the requirements in these Appendices be followed verbatim? 167 How should the operator address "must" and "shall" statements in the standard? In some cases, the standard provides for an alternative action if the "must" and "shall" statements are not implemented. 187 Discussion at the Houston workshop implied an operator needs to justify use of DA. Since DA is an accepted assessment method in the rule, why does an operator need to justify it over ILI or hydrotesting?
Guidance Information	1. Operators are only required to have an ECDA plan if they intend to use ECDA to assess covered pipe segments. 2. The ECDA plan must describe in detail how the four process steps (pre-assessment, indirect examination/inspection, direct examination, and post assessment) will be implemented to evaluate the external corrosion threat to the pipeline. Direct Assessment does not apply to all threats and limitations to its application are presented in NACE SP0502-2008. In addition to specific procedures, the plan must explain: a) the objectives of what will be accomplished, b) how specific work activities are to be accomplished, c) roles and responsibilities of personnel who will accomplish those objectives, as well as the specific qualifications of those personnel responsible for specific activities and functions, as required by §192..915(a) and (b). 3. A failure to have an ECDA plan or a failure to have an adequate ECDA plan would be cited under §192.925(b). Specific concerns with the pre-assessment, indirect examination, direct examination, or post assessment process should be cited under the applicable paragraph in §192.925(b). 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 5. Selected Final Orders Referencing §192.925(b): a) **Carolina Gas Transmission Corporation [2-2007-1010], (July 15, 2010), Item 2A,** CGT failed to develop and implement a direct assessment plan that adequately addressed indirect assessment, direct examination, and post-assessment procedures. Specifically, it alleged that Respondent's procedures did not provide for integrating ECDA indirect inspection pipeline coating indication data with encroachment and foreign line crossing data to evaluate covered segments for the threat of third-party damage and did not address such threats, as required by§ 192.917(e)(l).

Examples of a Probable Violation or Inadequate Procedures	1. Failure to have a plan in place that defined the ECDA process if the operator intends to use ECDA. 2. The ECDA plan was inadequate. 3. ECDA plan did not combine pre-assessment, indirect examination/inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of their pipeline. 4. Failure to evaluate the limitations of ECDA for their pipeline systems. 5. Plan for ECDA did not include objectives of what would be accomplished in the assessment process. 6. Plan for ECDA did not include provisions for how specific work activities are to be accomplished. 7. Plan for ECDA did not include the roles and responsibilities of personnel who will accomplish the objectives. 8. Plan for ECDA did not include the required specific qualifications for those personnel responsible for the ECDA activities and functions. 9. Failure to implement the written ECDA plan. 10. Failure to follow the written ECDA plan. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. ECDA plan and/or procedures. 3. Records. 4. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ECDA process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.925(b)(1)
Section Title	What are the requirements for using External Corrosion Direct Assessment (ECDA)?
Existing Code Language	(b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4, and in NACE SP0502-2008 (incorporated by reference, see §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1). (1) Pre-assessment. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502-2008, section 3, the plan's procedures for pre-assessment must include- (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and (ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE SP0502-2008, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 74 FR 48593, August 11, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 6.4. NACE SP0502-2008, Pipeline External Corrosion Direct Assessment Methodology.

	GTI External Corrosion Direct Assessment (ECDA) Implementation Protocol. Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs, November 1, 2010 Supplemental Guidance Appendix B.07, White Paper, Assessing for Third Party Damage. Supplemental Guidance Appendix D.01, External Corrosion Direct Assessment on Problematic Areas. PHMSA Gas Transmission Integrity Management FAQs: 104 ASME/ANSI B31.8S, Appendix B, section B1.3, Indirect Examinations, states that the secondary indirect examination method must evaluate at least 25% of each ECDA region. NACE Standard RP0502-2002, section 4.1.2 states that the indirect inspection step requires the use of at least two inspections over the entire length of each ECDA region. The requirements in the two standards appear to conflict. Which requirement should be implemented? 129 Can I use an indirect assessment tool for ECDA that is not listed in Table 2 of NACE RP-0502-2002? 177 Can operators aggregate ECDA regions after the process is started and they determine that some regions have common features? 198 Use of Guided Wave technology in ECDA 218 If DA is not currently accepted as a primary assessment method for third party damage, and the threat of third party damage is present, does the rule require that DA always be accompanied by either a pressure test, or ILI, or another assessment method that is capable of assessing third party damage? 242 How can I demonstrate that I have applied more restrictive criteria the first time I used ECDA (required by 192.925(b)(1)-(3) and NACE-0502-2002)? 243 What does PHMSA expect to see in a direct assessment feasibility study? 248 What are the basic regulatory requirements for cased pipe monitoring and inspection and what code sections apply? 249 Incorrect Pre-Assessment Data: If an operator creates regions based on pre-assessment data and during the direct examination determines that construction documentation was incorrect and the cased pipe should have been in a different region, does the operator have to perform additional direct examinations on cased pipe in that region? 250 No Previous Monitoring Data: If an operator has cased pipe that has not been monitored on an annual basis (no annual C/S readings) because casing wires and vents were not installed, but the operator has documentation on the construction, including the original pressure test, of the cased pipe and the indirect inspection results show that the casing is not shorted to the carrier pipe, what must the operator do to assess and monitor the pipeline during future assessments?

	251 Filled, Shorted, and an Incomplete Inspection: If an operator performs Guided Wave Ultrasonic Testing (GWUT) on a shorted and filled cased pipe, but is unable to clear the short and does not get 100% coverage with the GWUT inspection, has the operator satisfied the assessment requirements? 252 Filled, Isolated, and Not Following Go-No Go Target Items: If an operator does not have a prior assessment on a filled, cased pipe and completes a GWUT inspection, but is unable to follow all of the GWUT Go-No Go Target Items, has the operator satisfied the assessment requirements? 253 Fifty Casings in One Region: If an operator places all of their cased crossings in one region regard-less of specific differences in casings based on the pre-assessment data, is this always wrong? 254 Each Casing in Their Own Region: Is it permissible for an operator to place each of its cased crossings in separate region regardless of similarities with other cased crossings? 255 Reassessment on Filled Casings that have not Experienced a Major Change in Status: The guidelines state that "[a]ny indication of a change in casing integrity, or (for a filled casing) fill level or fill quality based on an evaluation of the casing monitoring program data using the guidelines in Exhibit D" is an indication with "immediate" priority. Would minor changes that are expected or for which there is a valid explanation meet this criteria for an "immediate" priority? 256 All Casing Low Risk: Do small operators with very few cased crossings still have to do a direct examination even if all of their cased crossings are low risk and filled? 257 Direct Examinations to Demonstrate ECDA Effectiveness: Do small operators with very few cased crossings still have to do effectiveness digs on cased crossings? 258 Corrosion Growth Rate: What is the proper method for determining corrosion growth rate that should be used on cased crossings when calculating reassessment intervals? 263 Direct Examination Example #1: An operator has two casing regions in a pipeline segment which are being assessed by ECDA. Region A has multiple casings, some of which are filled and some of which are unfilled. Region B has multiple casings, all of which are filled. There are no "immediate" or "scheduled" indications at any of the casings. All indications in both regions are "monitored." How many direct examinations need to be performed? 264 Direct Examination Example #2: An operator has a pipeline segment with one region containing 5 filled casings. During indirect examination performed for a 7-year reassessment, the operator identifies that one of the casings is metallically shorted to the carrier pipe. None of the other four casings had any indications. How many direct examinations need to be performed?

	265 Direct Examination Example #3: An operator has a pipeline segment with one Region containing 3 filled and 2 unfilled casings. During indirect examination performed for an initial assessment, the operator identifies that one of the filled casings is metallically shorted to the carrier pipe and that both unfilled casings have electrolytic shorts. None of the other casings had any indications. How many direct examinations need to be performed? 266 Direct Examination Example #4: An operator has a pipeline segment with two regions: Region A has 5 casings (3 unfilled and 2 filled) and Region B has 5 unfilled casings. During indirect examination performed for a 7-year reassessment, the operator identifies that one of the unfilled casings in Region A is electrolytically shorted to the carrier pipe. None of the other casings in either region had any indications. How many direct examinations need to be performed? 267 If a casing has been filled with wax per the PHMSA guidelines and a monitoring program has been implemented and followed in accordance with the PHMSA guidelines, does the casing have to be reassessed every 7 years if testing indicates there are no immediate indications? 268 Once an operator has wax filled a casing, does this allow the operator to reprioritize the filled casing within the next integrity re-assessment cycle? 269 What are the definitions of DA, Direct Assessment and DE, Direct Examination? 271 How will PHMSA handle casing assessments made before the guidance material was made public (when operators used ECDA but may not have followed the guidelines entirely)? 272 How would one handle a cased segment that has the attributes of Item 1 and Item 4 (from Exhibit B)? 273 If an operator has a pipeline system that operates at pressures less than 30% SMYS, and conducts a baseline assessment for external corrosion on all cased pipe using ECDA, can subsequent re-assessments be conducted using the low stress reassessment method (49 CFR 192.941), even though all of the casings were not directly examined during the baseline assessment?
Guidance Information	1. ECDA Pre-assessment process is required to comply with ASME B31.8S-2004, Section 6.4 and NACE SP0502-2008. Pre-assessment (NACE SP0502-2008, section 3.1.1) is a threefold process to determine: a) if ECDA is feasible for the pipeline to be evaluated, b) identify ECDA regions and, c) select Indirect Inspection Tools. 2. As part of the pre-assessment, the operator must have identified, collected and integrated adequate data to fully understand the characteristics of the pipeline being assessed. Assessment regions must be based on the use of the data integration results. A minimum of 2 complementary tools must be selected such that the strengths of one tool compensate for the limitations of the other tool. The selected tools must be able to assess and reliably detect coating holidays and the selection basis must be documented. If the operator utilized an indirect inspection method not listed in NACE SP0502-2008, Appendix A, the method's applicability, validation basis, equipment used, application procedure, and

	utilization of data must be documented. When ECDA pre-assessment is conducted on a covered segment for the first time, more restrictive criteria must be applied. 3. §192.925(b)(1) would generally not be cited for failures to maintain documentation related to the ECDA pre-assessment. §192.947(g) establishes the requirements for ECDA record retention. 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 5. Selected Final Orders Referencing §192.925(b)(1): a) **Equitable Resources (A.K.A Equitable Gas Co.), [1-2006-1006], (May 13, 2010), Item 2D,** Equitable failed to document the basis on which it selected at least two different, but complementary, indirect assessment tools. Equitable argued the regulation does not require it to document the basis for tool selection. The regulation requires an operator, as part of its pre-assessment procedures, to include "the basis on which an operator selects at least two different, but complimentary indirect assessment tools to assess each ECDA Region". b) **Centerpoint Energy Gas Transmission, [4-2007-1004], (February 11, 2011), Item 6,** Operator failed to comply with its own procedures and requirements of Section 3 of NACE RP 0502-2002. The Notice identified four separate violations of the NACE standard and its own procedures: (1) the operator failed to define minimum data collection requirements for conducting pre-assessments; (3) the operator failed to document whether an ECDA feasibility assessment had been conducted; and (4) the operator failed to document either the specific indirect inspection tools that were ultimately chosen or the basis for choosing them. c) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 8A,** Operator did not have documentation showing what assumptions had been made or what information was required to assure the feasibility of each ECDA project. **d) Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 8B,** Operator failed to implement an ECDA plan that included pre-assessment procedures meeting the requirements of ASME B31.8S. Specifically, the operator failed to follow its own procedure for conducting feasibility assessments on each ECDA performed. There was no documentation showing feasibility assessments had been performed.
Examples of a Probable Violation or Inadequate Procedures	1. Data to support ECDA pre-assessment was not identified, collected, and documented. (NACE SP0502-2008, Section 3.2) 2. Failure to document the performance of the ECDA feasibility assessment required by §192.947(g). 3. An ECDA feasibility study was not conducted to determine the applicability of ECDA to the affected segment. (NACE SP0502-2008, Section 3.3) 4. At least two different, but complementary indirect assessment tools to assess the ECDA region were not selected. (NACE SP0502-2008, Section 3.4) 5. Failure to identify which indirect inspection tools would work reliably in the ECDA areas or regions. (NACE SP0502-2008, Section 3.4)

	6. The basis for ECDA tool selection was not documented required by §192.947(g). 7. The selection of a tool not listed in Appendix A of NACE SP0502 was not documented or justified. 8. ECDA Regions were not identified. (NACE SP0502-2008, Section 3.5) 9. There were not a sufficient number of ECDA Regions identified. (NACE SP0502-2008, Section 3.5) 10. More restrictive criteria were not applied when conducting ECDA pre-assessment for the first time on a covered segment as required by §192.925(b)(1)(a). 11. Feedback was not incorporated at all appropriate opportunities throughout the ECDA process. See NACE SP0502-2008 Figure 2. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Records. 3. Operator's written ECDA process/procedures. 4. ECDA assessment report. 5. Maps of ECDA region identification. 6. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ECDA pre-assessment process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.925(b)(2)
Section Title	What are the requirements for using External Corrosion Direct Assessment (ECDA)?
Existing Code Language	(b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4, and in NACE SP0502-2008 (incorporated by reference, see §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1). …… (2) Indirect examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502-2008, section 4, the plan's procedures for indirect examination of the ECDA regions must include- (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; (ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected; (iii)Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and (iv)Criteria for scheduling excavation of indications for each urgency level.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 74 FR 48593, August 11, 2010
Interpretation Summaries	

Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 6.4. NACE SP0502-2008, Pipeline External Corrosion Direct Assessment Methodology. GTI External Corrosion Direct Assessment (ECDA) Implementation Protocol. Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs, November 1, 2010 Supplemental Guidance Appendix B.07, White Paper, Assessing for Third Party Damage. Supplemental Guidance Appendix D.01, External Corrosion Direct Assessment on Problematic Areas. PHMSA Gas Transmission Integrity Management FAQs: 104 ASME/ANSI B31.8S, Appendix B, section B1.3, Indirect Examinations, states that the secondary indirect examination method must evaluate at least 25% of each ECDA region. NACE Standard RP0502-2002, section 4.1.2 states that the indirect inspection step requires the use of at least two inspections over the entire length of each ECDA region. The requirements in the two standards appear to conflict. Which requirement should be implemented? 129 Can I use an indirect assessment tool for ECDA that is not listed in Table 2 of NACE RP-0502-2002? 177 Can operators aggregate ECDA regions after the process is started and they determine that some regions have common features? 213 At what point during ECDA does one move from severe, moderate, minor to immediate, scheduled, monitored? 242 How can I demonstrate that I have applied more restrictive criteria the first time I used ECDA (required by 192.925(b)(1)-(3) and NACE-0502-2002)? 257 Direct Examinations to Demonstrate ECDA Effectiveness: Do small operators with very few cased crossings still have to do effectiveness digs on cased crossings? 258 Corrosion Growth Rate: What is the proper method for determining corrosion growth rate that should be used on cased crossings when calculating reassessment intervals? 263 Direct Examination Example #1: An operator has two casing regions in a pipeline segment which are being assessed by ECDA. Region A has multiple casings, some of which are filled and some of which are unfilled. Region B has multiple casings, all of which are filled. There are no "immediate" or "scheduled" indications at any of the casings. All indications in both regions are "monitored." How many direct examinations need to be performed?

	264 Direct Examination Example #2: An operator has a pipeline segment with one region containing 5 filled casings. During indirect examination performed for a 7-year reassessment, the operator identifies that one of the casings is metallically shorted to the carrier pipe. None of the other four casings had any indications. How many direct examinations need to be performed? 265 Direct Examination Example #3: An operator has a pipeline segment with one Region containing 3 filled and 2 unfilled casings. During indirect examination performed for an initial assessment, the operator identifies that one of the filled casings is metallically shorted to the carrier pipe and that both unfilled casings have electrolytic shorts. None of the other casings had any indications. How many direct examinations need to be performed? 266 Direct Examination Example #4: An operator has a pipeline segment with two regions: Region A has 5 casings (3 unfilled and 2 filled) and Region B has 5 unfilled casings. During indirect examination performed for a 7-year reassessment, the operator identifies that one of the unfilled casings in Region A is electrolytically shorted to the carrier pipe. None of the other casings in either region had any indications. How many direct examinations need to be performed?
Guidance Information	1. The ECDA Indirect Examination/Inspection is required to comply with ASME B31.8S-2004, Section 6.4 and NACE SP0502-2008, Section 4 to identify and characterize the severity of coating fault indications, other anomalies, and areas at which corrosion activity may have occurred or may be occurring, and establish priorities for excavation. 2. The indirect examination step involves applying two complementary aboveground inspections over the entire length of each ECDA region to identify and define the severity of coating faults and areas where corrosion may have occurred. The boundaries of each ECDA region must be clearly marked by the operator (NACE SP0502-2008, Section 4.2.1) The ECDA plan must specify the physical spacing of readings (and the practices for changing the spacing as needed) such that suspected corrosion activity on the segment can be detected and located (NACE SP0502-2008, Section 4.2.3). The purpose of conducting indirect examinations of ECDA regions is to identify the location of suspected coating defects and the location of suspected corrosion areas. During the indirect inspection step, those coating faults or corrosion indications are to be aligned and integrated with other data on the pipeline. The results of both survey tools are to be compared and evaluated, then the fault or indication severity determined. The severity classification is used to help establish priorities for excavation during step 3 of the ECDA process (192.925(b)(3)). For the initial ECDA on a region, operators must apply and document the application of more restrictive criteria. 3. Indirect examinations/inspections must be conducted within the same season to be considered complimentary tools. 4. If Guided Wave is used as a complimentary tool, no notification to PHMSA is required. If used as a stand alone tool, notification is required to PHMSA for the use of “other” technology.

	5. If Guided Wave is used to assess a cased crossing, all 18 elements of the Guided Wave checklist must be addressed. 6. All personnel involved in the indirect examination process are required to be qualified as per 192.915 and Subpart N.§192.925(b)(2) would generally not be cited for failures to maintain documentation related to the ECDA indirect examination. §192.947(g) establishes the requirements for ECDA record retention. 7. Selected Final Orders Referencing §192.925(b)(2): a) **Equitable Resources (A.K.A Equitable Gas Co.), [1-2006-1006], (May 13, 2010), Item 2G,** Equitable failed to align and compare ECDA inspection tool data on Line H-153. Equitable's review of the three separate tool reports failed to comply with the alignment and comparison procedures required either by the regulation or company procedures. b) **Equitable Resources (A.K.A Equitable Gas Co.), [1-2006-1006], (May 13, 2010), Item 2I,** Equitable failed to properly perform the indirect assessment step of the ECDA process. Equitable claimed the tool identified the bare pipe and this was confirmed by direct examination. c) **Equitable Resources (A.K.A Equitable Gas Co.), [1-2006-1006], (May 13, 2010), Item 2J,** Equitable violated §192.917(e)(1) by failing to address third party damage as part of its pre-assessment process. They also violated §192.925(b)(2) by failing to have a sufficiently documented process for integrating and analyzing ECDA and third party damage data or for identifying potential area of third-parry damage that required remedial action. Equitable admitted that it had reviewed Line H-153 data alongside aerial alignment maps and in the field to determine the location of foreign line crossings only after the inspection.
Examples of a Probable Violation or Inadequate Procedures	1. More restrictive criteria were not applied when conducting ECDA indirect examination for the first time on a covered segment. 2. Criteria for identifying and documenting those indications that must be considered for excavation and direct examination were not specified. 3. Considerations for tool sensitivity, individual tool specifications, and tool spacing requirements were not addressed. 4. Indirect examinations that conform to generally accepted industry practices were not specified and performed. 5. Conflicting results from indirect inspection tools were not addressed. 6. Physical spacing of readings and/or the criteria for changing the spacing if and when needed were not specified. 7. Indirect examinations were not performed over the entire length of each ECDA Region. 8. Failure to use two complimentary indirect examination tools. 9. Criteria for defining the urgency level with which excavation and direct examination of indications will be conducted were not specified. 10. Pre-assessment data (such as third party damage) was not factored into the criteria for defining the urgency with which excavation and direct examination of indications will be conducted. 11. Encroachment and foreign line crossing data was not integrated with ECDA

	indirect examination data. 12. Feedback was not incorporated at all appropriate opportunities throughout the ECDA process. 13. Criteria for classification of the severity of each indication was not specified. 14. The boundaries of the ECDA Region were not clearly identified . *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. ECDA plan/process/procedures. 3. ECDA report. 4. Tool selection criteria. 5. Maps of ECDA Areas selected for indirect examination. 6. Excavation schedules. 7. Records. 8. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ECDA indirect examination process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.925(b)(3)
Section Title	What are the requirements for using External Corrosion Direct Assessment (ECDA)?
Existing Code Language	(b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4, and in NACE SP0502-2008 (incorporated by reference, see §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1). ……… (3) Direct examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502-2008, section 5, the plan's procedures for direct examination of indications from the indirect examination must include- (i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; (ii) Criteria for deciding what action should be taken if either: (A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE SP0502-2008), or (B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE SP0502-2008); (iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and (iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE SP0502-2008.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 74 FR 48593, August 11, 2010
Interpretation Summaries	

Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 6.4. NACE SP0502-2008, Pipeline External Corrosion Direct Assessment Methodology. GTI External Corrosion Direct Assessment (ECDA) Implementation Protocol. Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs, November 1, 2010 Supplemental Guidance Appendix B.07, White Paper, Assessing for Third Party Damage. Supplemental Guidance Appendix D.01, External Corrosion Direct Assessment on problematic Areas. Supplemental Guidance Appendix D.02, External Corrosion Direct Assessment Excavation Location Selection. PHMSA Gas Transmission Integrity Management FAQs: 130 Section 192.925(b)(3)(iii) requires notification procedures for any changes to my ECDA plan. Does this mean I have to notify OPS every time my plan changes? 177 Can operators aggregate ECDA regions after the process is started and they determine that some regions have common features? 203 For the first time using DA you were required to do an extra direct examination. Does this mean the "first time" on each covered segment, or the first time you do DA (ever)? 232 What timeframes apply to "discovery" of conditions presenting a potential threat to the integrity of a pipeline when using Direct Assessment? 242 How can I demonstrate that I have applied more restrictive criteria the first time I used ECDA (required by 192.925(b)(1)-(3) and NACE-0502-2002)? 254 Each Casing in Their Own Region: Is it permissible for an operator to place each of its cased crossings in separate region regardless of similarities with other cased crossings? 256 All Casing Low Risk: Do small operators with very few cased crossings still have to do a direct examination even if all of their cased crossings are low risk and filled? 257 Direct Examinations to Demonstrate ECDA Effectiveness: Do small operators with very few cased crossings still have to do effectiveness digs on cased crossings? 262 Minimum Number of Direct Examinations: An operator has multiple casing regions in a pipeline segment and each region has multiple casings. A variety of immediate, scheduled, and monitored indications were identified. How many direct examinations must be made in the ECDA process?

	263	Direct Examination Example #1: An operator has two casing regions in a pipeline segment which are being assessed by ECDA. Region A has multiple casings, some of which are filled and some of which are unfilled. Region B has multiple casings, all of which are filled. There are no "immediate" or "scheduled" indications at any of the casings. All indications in both regions are "monitored." How many direct examinations need to be performed?
	264	Direct Examination Example #2: An operator has a pipeline segment with one region containing 5 filled casings. During indirect examination performed for a 7-year reassessment, the operator identifies that one of the casings is metallically shorted to the carrier pipe. None of the other four casings had any indications. How many direct examinations need to be performed?
	265	Direct Examination Example #3: An operator has a pipeline segment with one Region containing 3 filled and 2 unfilled casings. During indirect examination performed for an initial assessment, the operator identifies that one of the filled casings is metallically shorted to the carrier pipe and that both unfilled casings have electrolytic shorts. None of the other casings had any indications. How many direct examinations need to be performed?
	266	Direct Examination Example #4: An operator has a pipeline segment with two regions: Region A has 5 casings (3 unfilled and 2 filled) and Region B has 5 unfilled casings. During indirect examination performed for a 7-year reassessment, the operator identifies that one of the unfilled casings in Region A is electrolytically shorted to the carrier pipe. None of the other casings in either region had any indications. How many direct examinations need to be performed?
	269	What are the definitions of DA, Direct Assessment and DE, Direct Examination?
	270	If no casings with a region (hazardous liquids) test as electrically shorted to the carrier pipe but there is one DCVG indication near one of the casing ends - what direct exams are required? Of course, the end of the casing that might contain the DCVG indication should be one direct exam and the other end of that same casing should be another direct exam. But, for the rest of the casings that have no indications nearby, does examining both ends of one casing constitute one direct exam or is excavation of each end of a casing considered as two direct exams?
	271	How will PHMSA handle casing assessments made before the guidance material was made public (when operators used ECDA but may not have followed the guidelines entirely)?
	272	How would one handle a cased segment that has the attributes of Item 1 and Item 4 (from Exhibit B)?
	273	If an operator has a pipeline system that operates at pressures less than 30% SMYS, and conducts a baseline assessment for external corrosion on all cased pipe using ECDA, can subsequent re-assessments be conducted using the low stress reassessment method (49 CFR 192.941), even though all of the casings were not directly examined during the baseline assessment?

	274 Must an operator always perform a 100% direct examination inspection of the carrier pipe within the casing under Step 3, Direct Examination, when doing an ECDA assessment? 276 With regard to FAQ 274 - Is the operator required to directly examine the entire surface of the carrier pipe within the casing? 277 NACE RP 0502-2002 section 5.1.2 states "The Direct Examination Step requires excavations to expose the pipe surface so that measurements can be made on the pipeline and in the immediate surrounding environment." What tools can an operator use to satisfy this requirement for a pipeline within a casing? Can an operator use GWUT as a means of conducting a direct examination of a pipeline within a casing?
Guidance Information	1. Direct examination is the third step in the ECDA process. The objectives of the NACE SP0502-2008, Section 5.1.6, direct examination are to excavate selected locations and to determine the severity, collect further data on corrosion activity, determine root causes, remediate defects, and process data for future evaluations. At least two excavations must occur in each ECDA region containing HCA segments when conducting the ECDA process for the first time. Additionally, more restrictive criteria for direct examination must be applied when conducting ECDA for the first time on a covered segment. FAQ-242 provides further guidance on demonstrating the use of more restrictive criteria when conducting ECDA for the first time. 2. §192.925(b)(3) would generally not be cited for failures to maintain documentation related to the ECDA direct examination. §192.947(g) establishes the requirements for ECDA record retention. 3. All personnel involved in the indirect examination process are required to be qualified as per §192.915 and Subpart N. Personnel qualification deficiencies would be cited under §192.915 for personnel performing those tasks defined in §192.915. Deficiencies in the qualification of personnel performing covered tasks under the operator's OQ Plan should be cited under Subpart N. 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 5. Selected Final Orders Referencing §192.925(b)(3): a) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 8I,** Operator failed to implement ECDA procedures that met the requirements of NACE RP 0502-2002 for all required excavations. Specifically, OPS' review of several ECDA projects showed that the operator performed only half the number of excavations that were required under NACE and the operator's own procedures.
Examples of a Probable Violation or Inadequate Procedures	1. Data to support ECDA direct examination was not identified and collected. 2. More restrictive criteria were not applied when conducting ECDA direct examination for the first time on a covered segment. 3. Direct examinations that conform to generally accepted industry practices were not specified and performed. 4. Excavations based on priority categories per NACE SP0502-2008 were not performed.

	5. Minimum requirements for data collection, measurements, and recordkeeping to evaluate coating condition and significant corrosion defects at each excavation location were not established and implemented. 6. The number and location of direct examinations on each ECDA region were not established in accordance with NACE SP0502-2008. 7. The remaining strength at locations where corrosion defects were found was not determined. 8. The root cause of all significant corrosion activity was not determined. 9. All other indications that occur in the pipeline segment where similar root-cause conditions exist were not identified and reevaluated. 10. Future external corrosion resulting from significant root causes was not mitigated and precluded from occurring. 11. An evaluation to categorize the need for repairs and classify the severity of individual indications was not performed. 12. A basis to reclassify and reprioritize indications was not established. 13. A process was not developed to consider the use of assessment methods other than ECDA to assess the impact of defects other than external corrosion discovered during direct examination. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows omission or deficiency in the Plan or Program. 2. ECDA process/procedures. 3. ECDA report. 4. Pipeline inspection reports. 5. Maps of ECDA areas selected for direct examination. 6. Excavation schedules. 7. Records. 8. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ECDA direct examination process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.925(b)(4)
Section Title	What are the requirements for using External Corrosion Direct Assessment (ECDA)?
Existing Code Language	(b) General requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4, and in NACE SP0502-2008 (incorporated by reference, see §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1). …. (4) Post assessment and continuing evaluation. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502-2008, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include- (i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and (ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in §192.939. (See Appendix D of NACE SP0502-2008.)
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 74 FR 48593, August 11, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 6.4. NACE SP0502-2008, Pipeline External Corrosion Direct Assessment Methodology. GTI External Corrosion Direct Assessment (ECDA) Implementation Protocol.

	Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs, November 1, 2010 Supplemental Guidance Appendix B.07, White Paper, Assessing for Third Party Damage. Supplemental Guidance Appendix D.01, External Corrosion Direct Assessment on problematic Areas. Supplemental Guidance Appendix G.01, Calculating Re-Assessment Interval. PHMSA Gas Transmission Integrity Management FAQs: 197 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? 255 Reassessment on Filled Casings that have not Experienced a Major Change in Status: The guidelines state that "[a]ny indication of a change in casing integrity, or (for a filled casing) fill level or fill quality based on an evaluation of the casing monitoring program data using the guidelines in Exhibit D" is an indication with "immediate" priority. Would minor changes that are expected or for which there is a valid explanation meet this criteria for an "immediate" priority? 258 Corrosion Growth Rate: What is the proper method for determining corrosion growth rate that should be used on cased crossings when calculating reassessment intervals? 267 If a casing has been filled with wax per the PHMSA guidelines and a monitoring program has been implemented and followed in accordance with the PHMSA guidelines, does the casing have to be reassessed every 7 years if testing indicates there are no immediate indications? 268 Once an operator has wax filled a casing, does this allow the operator to reprioritize the filled casing within the next integrity re-assessment cycle?
Guidance Information	1. The Post Assessment of ECDA is critical to the outcome of the process. The information obtained during the first three steps is evaluated to determine the need for follow up inspections/examinations. Incomplete data/process completion prevents the overall effectiveness of Direct Assessment. Key issues that should be addressed in the post-assessment include: a. Calculation of remaining life of each ECDA region, b. Determining reassessment intervals, c. Identifying performance measures, d. Validating the ECDA process, and e. Feedback and continuous improvement process 2. §192.925(b)(4) would generally not be cited for failures to maintain documentation related to the ECDA post-assessment. §192.947(g) establishes the requirements for ECDA record retention. 3. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.

	4. Selected Final Orders Referencing §192.925(b)(4): a) **Equitable Resources (A.K.A Equitable Gas Co.), [1-2006-1006], (May 13, 2010), Item 2L,** Equitable failed to develop adequate post-assessment and continuing evaluation procedures. Equitable maintained they were in the Direct Examination phase of ECDA when the inspection was conducted and that post-assessment was not yet required. b) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 8K,** Operator failed to develop and implement procedures that met NACE RP 0502-2002 for post assessment and continuing evaluation. Specifically, the operator used the wrong NACE formula for its remaining life calculations, thereby creating a high probability that some anomalies in HCA segments would not be excavated, as required, prior to the next assessment. Further, although the operator's procedure included the NACE default corrosion rate, actual corrosion rates used in the calculations were not documented.
Examples of a Probable Violation or Inadequate Procedures	1. Data to support ECDA post assessment was not identified and collected. 2. Minimum requirements for data collection, measurements, and recordkeeping to evaluate the long term effectiveness of ECDA in addressing external corrosion in covered segments were not established and implemented. 3. An evaluation to categorize the need for repairs and classify the severity of individual indications was not performed. 4. A basis to reclassify and reprioritize indications was not established. 5. Criteria and internal notification procedures were not established and implemented for any changes in the ECDA Plan. 6. A process was not developed to consider the use of assessment methods other than ECDA to assess the impact of defects other than external corrosion discovered during direct examination. 7. One additional direct examination was not performed for process validation at a randomly selected location. 8. At least two additional direct examinations were not performed for process validation at a randomly selected location on an initial ECDA application. 9. Corrosion growth rate used to calculate reassessment intervals and reassessment intervals were not technically justified. 10. A reassessment interval was used that exceeds the maximum interval specified in 192.939 or Table 3 of B31.8S-2004. 11. Performance measures were not defined for ECDA effectiveness. 12. Performance measures were not monitored for ECDA effectiveness. 13. Feedback was not incorporated at all appropriate opportunities throughout the ECDA process. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows omission or deficiency in the Plan or Program. 2. ECDA process/procedures. 3. ECDA report. 4. Post assessment results. 5. Validation of ECDA process. 6. Direct examination records for process validation. 7. Reassessment intervals per line segment. 8. Operator Performance Measures. 9. Remaining life calculations. 10. Corrosion growth rates. 11. Changes to cathodic protection procedures resulting from post assessment. 12. Records. 13. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ECDA post-assessment process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.927(a) & (b)
Section Title	What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?
Existing Code Language	(a) Definition. Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas. (b) General requirements. An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4 and appendix B2. The ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas, and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must provide notification in accordance with §192.921 (a)(4) or §192.937(c)(4).
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-00-02** **Internal Corrosion in Gas Transmission Pipelines, August 29, 2000** The Office of Pipeline Safety (OPS) is issuing this bulletin to owners and operators of natural gas transmission pipeline systems to advise them to review their internal corrosion monitoring programs and operations. Operators should consider factors that influence the formation of internal corrosion, including gas quality and operating parameters. Operators should give special attention to pipeline alignment features that may contribute to internal corrosion by allowing condensates to settle out of the gas stream.

Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. NACE SP0206-2006, Internal Corrosion Direct Assessment. (not incorporated by reference) GRI-02/0057, Internal Corrosion Direct Assessment of Gas Transmission Pipelines - Methodology, April 30, 2002. Supplemental Guidance Appendix C.03, White Paper - Look Beyond. PHMSA Gas Transmission Integrity Management FAQs: 46 What are acceptable integrity assessment methods? 105 If an operator has no records indicating that a pipeline section contained water or other electrolytes, is the lack of records sufficient to demonstrate that ICDA is unnecessary downstream of that location until the next feed injection point? 107 Section 192.927(c)(5)(iii) states that the ICDA plan must include "provisions that analysis be carried out on the entire pipeline in which covered segments are present..." Please clarify what sections of the pipeline must the operator conduct this analysis. Also, please define the term "analysis." Is this intended to be ICDA pre-assessment or some other analysis? 126 Can Internal Corrosion Direct Assessment (ICDA) be used on a dry-gas system that was used previously to transport wet gas? 127 Must I notify OPS (or the appropriate State) if I plan to use ICDA to assess a system transporting gas with an electrolyte nominally present in the gas stream? 132 How do I determine a new reassessment schedule if I identify defects requiring remediation using ICDA during a CDA assessment? 147 Does an operator have to do a direct assessment for internal corrosion (where pigging and hydrostatic testing are impractical) if the operator can demonstrate by historical records such as gas quality, internal inspections, etc. that they have never identified an internal corrosion problem and that conditions conducive to internal corrosion do not exist? 153 Must I notify OPS/state regulators if I plan to use a different model for ICDA than the one referenced in the rule? 158 Must historical operating conditions be considered, or only current operating conditions, when using ICDA? 193 How can we include ICDA in our plan when there is no accepted standard? 235 If Guided Wave UT is used as part of the ICDA process, is it considered "other technology" requiring notification to OPS/states? 243 What does PHMSA expect to see in a direct assessment feasibility study? 269 What are the definitions of DA, Direct Assessment and DE, Direct Examination?
Guidance Information	1. The ICDA is only applicable for dry gas systems that have infrequent upsets which can result in electrolytes entering the system. The ICDA plan must meet all of the requirements of §192.927 and relevant sections of ASME B31.8S-

	2004. The plan must contain provisions for carrying out ICDA on the entire pipeline in which covered segments are present. Remedial activities may be limited to covered segments. 2. The entire life of the pipeline must be considered in determining whether or not ICDA would be appropriate. The plan should show that the operator is assessing the entire pipeline in the ICDA procedure. This is required because electrolyte may enter or leave the pipeline in areas that are not located in covered segments. Internal corrosion could be taking place in these sections of the pipeline. 3. Enforcement related to general ICDA requirements, plan or procedure content, or documentation of the applicability of ICDA to the covered segments should be cited against §192.927(b). §192.927(a) would normally not be a cited referenced as that section only provides a definition of ICDA. Violations with implementation of specific elements of ICDA (e.g., region identification, excavation locations, post-assessment) should reference one of the paragraphs under §192.927(c). 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 5. Selected Final Orders Referencing §192.927(a) & (b): a) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 9A,** Operator failed to identify areas along its pipeline where water or other electrolyte might be introduced during normal operation, to determine if internal corrosion were likely to exist, and by failing to provide an analysis or justification for eliminating internal corrosion as a threat. Specifically, the operator did not have a technical justification for eliminating the threat of internal corrosion in those areas where ECDA was being utilized and therefore should have been using ICDA or some other assessment method for internal corrosion.
Examples of a Probable Violation or Inadequate Procedures	1. ICDA was used as an assessment method but a documented ICDA plan had not been developed. 2. No process or procedures describing the requirements for the ICDA process. 3. Process or procedures did not meet all of the requirements of §192.927 or ASME B31.8S-2004, Section 6.4 and Appendix B.2. 4. Failure to follow ASME B31.8S-2004, Section 6.4 and Appendix B.2. 5. ICDA was not required to be applied to the entire pipeline in which covered segments are present. 6. The ICDA process was applied to a pipeline not suited for the process (e.g. wet gas, treated gas, no elevation data, etc.). *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows omission or deficiency in the Plan or Program. 2. ICDA plan/process/procedures. 3. ICDA report. 4. Operator maps of pipeline systems. 5. Documentation of the lack of electrolyte in the segment. 6. Records. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ICDA process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.927(c)(1)
Section Title	What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?
Existing Code Language	(c) The ICDA plan. An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring. (1) Preassessment. In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to-- (i) All data elements listed in Appendix A2 of ASME/ANSI B31.8S; (ii) Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (See paragraph (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline; (iii) Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and (iv) Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	

Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. NACE SP0206-2006, Internal Corrosion Direct Assessment (not incorporated by reference) GRI-02/0057, Internal Corrosion Direct Assessment of Gas Transmission Pipelines - Methodology, April 30, 2002. Supplemental Guidance Appendix C.03, White Paper - Look Beyond. Supplemental Guidance Appendix D.03, Minimal Data Elements for Dry Gas Internal Corrosion Direct Assessment. Supplemental Guidance Appendix D.04, Data Elements that Preclude the Use of Dry Gas Internal Corrosion Direct Assessment. PHMSA Gas Transmission Integrity Management FAQs: 81 What kinds of information must be integrated in performing a continual evaluation of pipeline integrity? 105 If an operator has no records indicating that a pipeline section contained water or other electrolytes, is the lack of records sufficient to demonstrate that ICDA is unnecessary downstream of that location until the next feed injection point? 107 Section 192.927(c)(5)(iii) states that the ICDA plan must include "provisions that analysis be carried out on the entire pipeline in which covered segments are present..." Please clarify what sections of the pipeline must the operator conduct this analysis. Also, please define the term "analysis." Is this intended to be ICDA pre-assessment or some other analysis? 158 Must historical operating conditions be considered, or only current operating conditions, when using ICDA? 193 How can we include ICDA in our plan when there is no accepted standard? 243 What does PHMSA expect to see in a direct assessment feasibility study?
Guidance Information	1. In the pre-assessment the operator must gather information and data needed to evaluate the feasibility of ICDA for covered segments and to identify regions and areas in covered segments where liquids may be entrained. As a minimum, the pre-assessment must collect the following: a) All data elements listed in ASME B31.8S-2004, Appendix A2 b) Information needed to support use of a model to identify areas where internal corrosion is most likely c) Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions d) Information where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes. 2. ICDA may only be used on dry gas systems. 3. The lack of a pre-assessment process or an inadequate pre-assessment process should be cited against §192.927(c).

	4. Deficiencies in implementing the pre-assessment process should be cited against §192.927(c)(1). 5. A failure to apply "more restrictive criteria" when conducting ICDA pre-assessment for the first time on a covered segment should be cited under §192.927(c)(5). 6. §192.927(c)(1) would generally not be cited for failures to maintain documentation related to the ICDA pre-assessment. §192.947(g) establishes the requirements for ICDA record retention. 7. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 8. Selected Final Orders Referencing §192.927(c)(1): a) **Centerpoint Energy Gas Transmission, [4-2007-1004], (February 11, 2011), Item 8,** Operator failed to evaluate the feasibility of ICDA for certain pipeline segments. Specifically, the operator failed to perform or document feasibility evaluations for ICDA pre-assessments performed on its FT-11 and ADT-8 lines. The operator did not document the basis for selecting the feasibility criteria for pigging, water upsets, and introduction of sludge. Also, the operator's ICDA pre-assessment data was of "poor quality" and that this "could lead" to improper determination of ICDA regions.
Examples of a Probable Violation or Inadequate Procedures	1. No process or procedure to describe the requirements for ICDA pre-assessment. 2. ICDA plan did not document requirements for ICDA pre-assessment. 3. Procedures did not document requirements for ICDA pre-assessment, region identification, and indirect inspection. 4. Failure to follow the ICDA plan or procedures for pre-assessment. 5. Failure to identify and collect the data needed to support the ICDA pre-assessment. 6. Failure to collect all the data required by ASME B31.8S-2004 Appendix A2. 7. Failure to determine which areas of the ICDA process were feasible for evaluating the integrity of their pipeline. 8. The data collected was not adequately integrated. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows omission or deficiency in the Plan or Program. 2. ICDA plan/process/procedures. 3. ICDA report. 4. Operator maps of pipeline systems. 5. Gas Quality records. 6. Internal corrosion failure reports. 7. Gas processing facility shutdowns. 8. Operator maps. 9. Records. 10. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ICDA process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.927(c)(2)
Section Title	What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?
Existing Code Language	(c) The ICDA plan. An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring. (2) ICDA region identification. An operator's plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02-0057, ``Internal Corrosion Direct Assessment of Gas Transmission Pipelines--Methodology," (incorporated by reference, see §192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations downstream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. NACE SP0206-2006, Internal Corrosion Direct Assessment (not incorporated by reference) GRI-02/0057, Internal Corrosion Direct Assessment of Gas Transmission Pipelines - Methodology, April 30, 2002. Supplemental Guidance Appendix C.03, White Paper - Look Beyond.

	Supplemental Guidance Appendix D.05, Internal Corrosion Direct Assessment - Region Definition. Supplemental Guidance Appendix D.06, Flow Modeling & Inclination Profile. PHMSA Gas Transmission Integrity Management FAQs: 46 What are acceptable integrity assessment methods? 105 If an operator has no records indicating that a pipeline section contained water or other electrolytes, is the lack of records sufficient to demonstrate that ICDA is unnecessary downstream of that location until the next feed injection point? 107 Section 192.927(c)(5)(iii) states that the ICDA plan must include "provisions that analysis be carried out on the entire pipeline in which covered segments are present..." Please clarify what sections of the pipeline must the operator conduct this analysis. Also, please define the term "analysis." Is this intended to be ICDA pre-assessment or some other analysis? 126 Can Internal Corrosion Direct Assessment (ICDA) be used on a dry-gas system that was used previously to transport wet gas? 127 Must I notify OPS (or the appropriate State) if I plan to use ICDA to assess a system transporting gas with an electrolyte nominally present in the gas stream? 147 Does an operator have to do a direct assessment for internal corrosion (where pigging and hydrostatic testing are impractical) if the operator can demonstrate by historical records such as gas quality, internal inspections, etc. that they have never identified an internal corrosion problem and that conditions conducive to internal corrosion do not exist? 153 Must I notify OPS/state regulators if I plan to use a different model for ICDA than the one referenced in the rule? 158 Must historical operating conditions be considered, or only current operating conditions, when using ICDA?
Guidance Information	1. For all covered segments an operator must identify the ICDA regions. Regions are identified through the integration of data collected in the pre-assessment (§192.927(c)(1). Physical data obtained in the pre-assessment step must be used to calculate the inclination angles along the entire covered segment within each ICDA region. In the region identification process, an operator must use the model in GRI 02-0057, ``Internal Corrosion Direct Assessment of Gas Transmission Pipelines--Methodology," (incorporated by reference, see §192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. 2. The lack of a process to identify ICDA regions or an inadequate process should be cited against §192.927(c). 3. If inadequate regions are identified due to the use of inadequate or inaccurate data, then the violation should cite §192.927(c)(1) rather than §192.927(c)(2).

	4. A failure to apply "more restrictive criteria" when conducting ICDA region identification for the first time on a covered segment should be cited under §192.927(c)(5). 5. §192.927(c)(2) would generally not be cited for failures to maintain documentation related to the ICDA region identification. §192.947(g) establishes the requirements for ICDA record retention 6. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. No plan or procedures that described the requirements for identifying ICDA regions. 2. ICDA plan or procedures for the identifying ICDA regions were inadequate. 3. Failure to follow ICDA plan or procedures for ICDA region identification. 4. ICDA regions were not technically justified. 5. Failure to identify a sufficient number of ICDA regions. 6. Failure to clearly define the boundaries of the ICDA Regions. 7. Failure to use the GRI 02-0057 model "Internal Corrosion Direct Assessment of Gas Transmission Pipeline – Methodology," or an equivalent model in identifying ICDA Regions. 8. Use of an alternate model for ICDA Region identification without demonstrating the equivalency to the GRI model. 9. Failure to consider bidirectional flow in the identification of the ICDA Regions. 10. Failure to consider pipeline configuration such as changes in pipe diameter, gas entry points, or other information to identify ICDA regions. 11. Failure to define the pipeline elevation changes. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows omission or deficiency in the Plan or Program. 2. ICDA plan/process/procedures. 3. ICDA report. 4. Maps of ICDA Regions. 5. Maps of system pipeline. 6. Elevation profiles. 7. Critical angle calculations. 8. Pipe segment characteristics. 9. Records. 10. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ICDA process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.927(c)(3)
Section Title	What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?
Existing Code Language	(c) The ICDA plan. An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring. (3) Identification of locations for excavation and direct examination. An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must- (i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §192.933; (ii) As part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method allowed by this subpart to assess the line pipe in each covered segment within the ICDA region for internal corrosion; and (iii) Evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with §192.933.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	

Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. NACE SP0206-2006, Internal Corrosion Direct Assessment (not incorporated by reference) GRI-02/0057, Internal Corrosion Direct Assessment of Gas Transmission Pipelines - Methodology, April 30, 2002. Supplemental Guidance Appendix C.03, White Paper - Look Beyond. Supplemental Guidance Appendix D.07. Direct Examination of a Dry Gas Internal Corrosion Direct Assessment Location. PHMSA Gas Transmission Integrity Management FAQs: 132 How do I determine a new reassessment schedule if I identify defects requiring remediation using ICDA during a CDA assessment? 235 If Guided Wave UT is used as part of the ICDA process, is it considered "other technology" requiring notification to OPS/states?
Guidance Information	1. The ICDA direct examination process must identify those locations where internal corrosion would be the most likely to occur. These locations must meet both the critical angle of inclination and be the locations that may trap liquids through their design. At least two locations in each ICDA region and within the covered segments in those regions must be identified and examined. At least one location must be the low point nearest the beginning of the ICDA region. The second location must be further downstream near the end of the ICDA region. 2. The lack of a process for ICDA direct examination or an inadequate process should be cited against §192.927(c). 3. A failure to apply "more restrictive criteria" when conducting ICDA direct examination for the first time on a covered segment should be cited under §192.927(c)(5). 4. Direct examination for internal corrosion may be performed using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques. If personnel qualification concerns are identified with the inspectors performing the measurements, reference should be made to the qualification requirements of §192.915, where applicable to that section, or Subpart N when a covered task under the operator's OQ Plan is performed by non-qualified personnel. 5. §192.927(c)(3) would generally not be cited for failures to maintain documentation related to the ICDA direct examination. §192.947(g) establishes the requirements for ICDA record retention

	6. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. No ICDA plan or procedures that describe requirements for the identification of locations for excavation and direct examination. 2. ICDA plan for the identification of locations for excavation and direct examination was inadequate. 3. Failure to follow ICDA plan or procedure for the identification of locations for excavating and direct examination. 4. Failure to identify a minimum of two locations for excavation within each ICDA Region within a covered segment. 5. Selected excavation locations did not include a low point (sage, drip, valve, manifolds, deadleg, or traps) within the covered segment. 6. Failure to excavate and examine all identified locations. 7. Failure to perform additional excavations for first time use of ICDA. 8. Failure to correctly identify the two locations for excavation within the ICDA Region. 9. A direct examination of those covered segment locations where internal corrosion is most likely to exist in accordance with the requirements of ASME B31.8S-2004 was not required or not completed using a generally accepted measurement technique. 10. The severity of identified defects during direct examination was not evaluated. 11. Defects identified during direct examination were not remediated per §192.933. 12. Failure to perform additional excavations in areas or where internal corrosion was found in the ICDA Region direct examination process. 13. The potential for internal corrosion was not evaluated in all pipeline sections (both covered and non-covered) with similar characteristics to the ICDA region containing the covered segment in which corrosion was found. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. ICDA plan/process/procedures. 4. ICDA report. 5. Excavation records. 6. Maps of ICDA Regions. 7. Pipeline system maps. 8. Pipe inspection reports. 9. Records. 10. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ECDA indirect examination process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.927(c)(4)
Section Title	What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?
Existing Code Language	(c) The ICDA plan. An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring. (4) Post-assessment evaluation and monitoring. An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes-- (i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §192.939. An operator must carry out this evaluation within a year of conducting an ICDA; and (ii) Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with §192.933. (A) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or (B) Assess the covered segment using another integrity assessment method allowed by this subpart.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	

Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. NACE SP0206-2006, Internal Corrosion Direct Assessment (not incorporated by reference) GRI-02/0057, Internal Corrosion Direct Assessment of Gas Transmission Pipelines - Methodology, April 30, 2002. Supplemental Guidance Appendix C.03, White Paper - Look Beyond. Supplemental Guidance Appendix G.01, Calculating Re-assessment Interval. PHMSA Gas Transmission Integrity management FAQs: 132 How do I determine a new reassessment schedule if I identify defects requiring remediation using ICDA during a CDA assessment?
Guidance Information	1. An operator must determine if the ICDA process was effective in locating areas of internal corrosion on covered segments. 2. If internal corrosion is found, continued monitoring of those segments is required to meet the requirements of 192.477, Internal Corrosion Control - Monitoring. 3. Some areas that must be evaluated are the extent and location of internal corrosion if found. By this, the operator must determine if the corrosion was only in the locations determined by the model. 4. The use of the largest found defect to determine the reassessment interval is a conservative approach. It assumes that the ICDA process may not have found all of the defects and to protect the integrity of the covered segment, the reassessment interval is the shortest based on the data obtained. 5. The ICDA process must provide for continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. 6. The lack of a process for post assessment evaluation and monitoring or an inadequate process would be cited against §192.927(c). 7. A failure to apply "more restrictive criteria" when conducting ICDA post-assessment for the first time on a covered segment should be cited under §192.927(c)(5). 8. Note that a failure to establish a minimum internal corrosion monitoring frequency should be cited as a violation of §192.477, Internal Corrosion Control – Monitoring

	9. §192.927(c)(4) would generally not be cited for failures to maintain documentation related to the ICDA post-assessment examination. §192.947(g) establishes the requirements for ICDA record retention 10. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. No ICDA plan or procedures that describe the requirements for post evaluation and monitoring. 2. The ICDA plan for post evaluation and monitoring was inadequate. 3. Failure to follow the plan or procedures for post assessment evaluation and monitoring. 4. The effectiveness of the ICDA process was not evaluated. 5. The reassessment interval was not technically justified. 6. The evaluation for reassessment interval was not completed within one year of completion of the assessment. 7. A reassessment interval was selected that exceeded the maximum reassessment intervals specified in 192.939 and Table 3 of ASME B31.8S-2004. 8. Failure to perform continual monitoring for each covered segment where internal corrosion has been identified. 9. Failure to perform continual monitoring by a suitable technique. 10. Failure to establish a minimum internal corrosion monitoring frequency in accordance with 192.477 (needs to be cited under 192.477). 11. Failure to conduct additional excavations downstream of locations where an electrolyte enters the pipeline when evidence of corrosion products was found. 12. Action was not taken when evidence existed of corrosion products in monitored covered segments. 13. Failure to identify an alternative integrity assessment method when general internal corrosion is found. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. ICDA plan/process/procedures. 4. ICDA report. 5. Post-assessment ICDA report 6. Maps of ICDA Regions. 7. Pipeline system maps. 8. Excavation reports. 9. Pipe inspection reports. 10. Records. 11. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ICDA post-assessment process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.927(c)(5)
Section Title	What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?
Existing Code Language	(c) The ICDA plan. An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring. (5) Other requirements. The ICDA plan must also include-- (i) Criteria an operator will apply in making key decisions (e.g., ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process; (ii) Provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience; and (iii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §192.933 may be limited to covered segments.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. NACE SP0206-2006, Internal Corrosion Direct Assessment (not incorporated by reference) GRI-02/0057, Internal Corrosion Direct Assessment of Gas Transmission Pipelines - Methodology, April 30, 2002. Supplemental Guidance Appendix C.03, White Paper - Look Beyond. PHMSA Gas Transmission Integrity Management FAQs: 107 Section 192.927(c)(5)(iii) states that the ICDA plan must include "provisions that analysis be carried out on the entire pipeline in which covered segments are present..." Please clarify what sections of the pipeline must the operator

	conduct this analysis. Also, please define the term "analysis." Is this intended to be ICDA pre-assessment or some other analysis? 203 For the first time using DA you were required to do an extra direct examination. Does this mean the "first time" on each covered segment, or the first time you do DA (ever)?
Guidance Information	1. The ICDA plan must define criteria to be applied in making key decisions (e.g., region identification, feasibility determinations) in implementing the pre-assessment stage of the ICDA process and must ensure the entire pipeline is assessed. This is required because the electrolyte may enter or leave the pipeline in areas that are not located in covered segments. Additionally, the ICDA plan must include provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience. 2. Lack of a process for implementing the other requirements of §192.927 or an inadequate process should be cited against §192.927(c). 3. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 4. ICDA analysis must include the entire pipeline and not just covered segments.
Examples of a Probable Violation or Inadequate Procedures	1. Plan, process or procedures do not describe other requirements for the ICDA process. 2. ICDA plan for defining other requirements was inadequate. 3. Failure to follow ICDA plan or procedures for implementing other requirements. 4. Criteria were not defined in the ICDA Plan for making key decisions (e.g., ICDA feasibility, ICDA Region identification, etc.) 5. More restrictive criteria were not required and/or implemented when conducting ICDA pre-assessment, ICDA region identification, identification of locations for excavation and direct examination, and post-assessment evaluation and monitoring. 6. ICDA plan did not contain provisions that analysis be carried out on the entire pipeline in which covered segments are present. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. ICDA plan/process/procedures. 4. ICDA report. 5. Records. 6. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the ICDA post-assessment process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.929
Section Title	What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?
Existing Code Language	(a) Definition. Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment. (b) General requirements. An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for-- (1) Data gathering and integration. An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (incorporated by reference, see §192.7), appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, Appendix A3. (2) Assessment method. The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-03-05** **Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines** RSPA's Office of Pipeline Safety (OPS) is issuing this advisory notice to owners and operators of gas and hazardous liquid pipelines to consider the threat from stress corrosion cracking (SCC) when developing and implementing Integrity Management Plans. Operators should determine whether their pipelines are susceptible to SCC and assess the impact of SCC on pipeline integrity. Based on

	this evaluation, an operator should prioritize application of additional in-line inspection and hydrostatic testing and take actions to remediate problem areas.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 7.3.2 and Appendix A3. Gas Piping Technology Committee (GPTC) NACE SP0204-2008, Stress Corrosion Cracking (SCC) Direct Assessment Methodology (not incorporated by reference). TTO-08, Stress Corrosion Cracking Study, Michael Baker Jr. Inc., January 2005. Supplemental Guidance Appendix C.03, White Paper - Look Beyond. Supplemental Guidance Appendix D.08, Stress Corrosion Cracking. Supplemental Guidance Appendix D.09, SCC Crack Growth Mechanism Models. Supplemental Guidance Appendix G.01, Calculating Re-assessment Interval. PHMSA Gas Transmission Integrity Management FAQs: 97 What types of notifications are required by the rule? 98 When must notifications be submitted? 99 What information must be in a notification? 128 When using Stress Corrosion Cracking Direct Assessment (SCCDA), must I consider conditions on portions of my pipeline not in high consequence areas? 223 What kind of data must I collect and evaluate to use stress corrosion cracking direct assessment (SCCDA)? 243 What does PHMSA expect to see in a direct assessment feasibility study?
Guidance Information	1. Currently two types of SCC that the gas integrity rule addresses are high pH and near neutral (or low) pH SCC. The requirements contained in ASME B31.8S-2004, Appendix A3 currently only apply to high pH SCC. ASME B31.8S-2004, Appendix A3.1 states that near neutral type SCC similarly requires an inspection and alternative mitigation plan. The only difference in the criteria for high-pH and near neutral SCC is the temperature criterion. 2. An assessment for near-neutral pH SCC requires a notification as "Other Technology". Failure to submit an "Other Technology" notification for the use of a near neutral SCC assessment plan should be cited under §192.949. 3. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 4. Selected Final Orders Referencing §192.929: a) **Centerpoint Energy Gas Transmission, [4-2007-1004], (February 11, 2011), Item 10,** Operator failed to provide in its IMP a systematic data collection and evaluation process for all covered segments. Specifically, the operator had four separate violations: (1) the operator failed to include in its SCCDA plan a requirement for the gathering and integration of data related to SCC at all sites. The company's procedures failed to require the collection of data on non-covered pipelines that were excavated; (2) the

	operator failed to follow its own procedures by not gathering and reviewing certain data elements used for SCCDA; (3) the operator failed to include a requirement in its procedure to notify PHMSA 180 days prior to using a "near-neutral" SCCDA plan; and (4) the operator failed to include a provision to perform a hydrostatic "spike test" following an in-service leak or rupture attributable to SCC. Violation (1) was upheld; violation (2) was withdrawn based on submission of Data Element Forms showing data had been evaluated; violation (3) was upheld; and violation (4) was withdrawn based on B31.8S does not require a "spike test", it requires a hydrostatic pressure test.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to follow written SCCDA procedures 2. Failure to follow the data collection requirements as specified in ASME B31.8S-2004 Appendix A3. 3. Failure to define criteria that require SCC evaluation. 4. Failure to assess pipe for high pH and/or near-neutral SCC if conditions warrant. 5. Failure to gather or evaluate data related to SCC at all sites excavated (for any reason) that are located in areas that meet the screening criteria in ASME B31.8S-2004. 6. Failure to use an acceptable assessment method as listed in ASME B31.8S - 2004 Appendix A3, Section 3.4. 7. An acceptable inspection, examination and evaluation approach was not specified and/or implemented. 8. The assessment results were not considered when determining reassessment intervals. 9. Failure to provide notification to PHMSA for assessment of near-neutral SCC. 10. Failure to consider relevant data from pipe not in covered segments in the SCC process. 11. Failure to remediate by appropriate methods any SCC that was discovered. 12. Failure to have a written hydrostatic retesting program for segments experiencing a failure or rupture due to SCC, or perform an engineering critical assessment to evaluate the risk and identify further mitigation methods. 13. Failure to perform a hydrostatic pressure test within one year of the failure of a segment experiencing a failure or rupture due to SCC. (ASME B31.8S-2004 Appendix A3). 14. Failure to follow the requirements of ASME B31.8S-2004 Appendix A3. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. SCCDA plan. 3. SCCDA report. 4. Records. 5. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the SCCDA process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.931
Section Title	How may Confirmatory Direct Assessment (CDA) be used?
Existing Code Language	An operator using the confirmatory direct assessment (CDA) method as allowed in §192.937 must have a plan that meets the requirements of this section and of §§192.925 (ECDA) and §192.927 (ICDA). (a) Threats. An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion. (b) External corrosion plan. An operator's CDA plan for identifying external corrosion must comply with §192.925 with the following exceptions. (1) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application. (2) The procedures for direct examination and remediation must provide that-- (i) All immediate action indications must be excavated for each ECDA region; and (ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region. (c) Internal corrosion plan. An operator's CDA plan for identifying internal corrosion must comply with §192.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region. (d) Defects requiring near-term remediation. If an assessment carried out under paragraph (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE SP0502-2008 (incorporated by reference, see §192.7), section 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with §192.933 until the operator has completed reassessment using one of the assessment techniques allowed in §192.937.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 75 FR 48593, August 11, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	

Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 6.2, 6.3, 7, Appendix A1, and Appendix B1. Gas Piping Technology Committee (GPTC) NACE SP0502-2008, Pipeline External Corrosion Direct Assessment Methodology Supplemental Guidance Appendix F.04, CDA and Reassessment Intervals Supplemental Guidance Appendix G.01, Calculating Re-assessment Interval PHMSA Gas Transmission Integrity Management FAQs: 40 How often must periodic integrity assessments be performed on HCA pipeline segments after the baseline assessment is completed? 46 What are acceptable integrity assessment methods? 216 Assuming a system operating below 30% SMYS and reassessment every 20 years, how much of a system must be assessed via CDA at the 7 and 14 year intervals? How do we determine where we must use CDA? 132 How do I determine a new reassessment schedule if I identify defects requiring remediation using ICDA during a CDA assessment? 133 Must I do a full assessment every 7 years if my pipeline is subject to threats other than external and internal corrosion? 173 Can a CDA be credited as a second assessment if an operator desires to move to a performance-based program? 228 Can the conduct of a successful CDA assessment extend the interval until the next required assessment using ILI, pressure testing, DA, or other technology?
Guidance Information	1. The preamble to the Federal Register Notice makes it clear that if problems are found through the implementation of CDA, then the operator needs to take additional actions. *The premise behind CDA is that it is used to confirm the acceptable integrity of a pipeline, already ensured by assessments in accordance with ASME/ANSI B31.8S. If confirmation is not successful, i.e., if problems are found, then an operator needs to take additional actions.* (Federal Register / Vol. 68, No. 240 / Monday, December 15, 2003 / Rules and Regulations at Page 69807.) 2. All covered pipelines must be assessed every 7 years after the initial baseline assessment. CDA is an interim assessment technique that may be used that provides operators with a method of validating the results of assessments of covered segments for external and internal corrosion threats. 3. CDA is not applicable for any threats other than external or internal corrosion. 4. Operators do not have to do a full assessment every 7 years even if their pipeline is subject to threats other than external and internal corrosion. Intervals for full assessments must be established per the requirements in 192.939. Maximum reassessment intervals vary with pipeline stress level as presented in the table in that section, but shorter intervals may be required if indicated by the operator's risk analysis. If an interval of longer than seven years is established, then some assessment must be performed no less frequently than every seven years. Confirmatory direct assessment, alone, is sufficient to fulfill this requirement.

	5. When §192.925 requirements for ECDA and §192.927 requirements for ICDA are improperly implemented for CDA, requirement violations should be cited under §192.931 for CDA. 6. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. CDA plan for external corrosion did not meet the requirements of 192.925 (except as noted in 192.931). 2. CDA plan for internal corrosion did not meet the requirements of 192.927 (except as noted in 192.931). 3. CDA was used for threats other than external and internal corrosion. 4. CDA was not performed within 7 and 14 years, if required, and no other assessment method was substituted. 5. Failure to follow requirements in the CDA plan. 6. CDA was used as a second assessment for credit towards the exceptional performance goals. 7. Reassessment was not scheduled per NACE SP0502-2008 when defects were discovered that required remediation prior to the next scheduled assessment. 8. Failure to reduce the pressure consistent with §192.933 until reassessment was completed using one of the assessment techniques allowed in §192.937. 9. CDA was used for external corrosion, but all immediate indications in each ECDA region on the covered segment were not remediated, in addition to the one scheduled indication. 10. CDA was used for internal corrosion, but at least one high risk location in each ICDA region on a covered segment was not excavated. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. CDA plan. 3. CDA report. 4. Excavation records. 5. Records and maps. 6. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the CDA process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.933(a)
Section Title	What actions must be taken to address integrity issues?
Existing Code Language	(a) General requirements. An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. (1) Temporary pressure reduction. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see §192.7) or AGA Pipeline Research Committee Project PR-3-805 ("RSTRENG," incorporated by reference, see §192.7) or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. (See appendix A to this part for information on availability of incorporation by reference information.) An operator must notify PHMSA in accordance with §192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through temporary reduction in operating pressure or other action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State. (2) Long-term pressure reduction. When a pressure reduction exceeds 365 days, the operator must notify PHMSA under §192.949 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-104, 72 FR 39012, 17 July, 2007

Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-13-04** **T.D. Williamson, Inc. Leak Repair Clamp Recall** **June 17, 2013** PHMSA advisory to alert all pipeline operators of a T.D. Williamson, Inc. (TDW) Leak Repair Clamp (LRC) recall issued by TDW on June 17, 2013. The recall covers all TDW LRCs of any pressure class and any size. The LRCs may develop a dangerous leak due to a defective seal. Hazardous liquid and natural gas pipeline operators should verify if they have any TDW LRCs subject to the recall by reviewing their records and equipment for installation of these LRCs. **Advisory Bulletin ADB-05-04** **Integrity Management Notifications for Gas Transmission Lines** Current regulations require operators to notify OPS and state pipeline safety agencies of certain events related to integrity management programs for gas transmission lines. This bulletin provides guidance on notifying OPS and state agencies and describes OPS' review of notifications. OPS expects this bulletin to improve the efficiency of the notification and review process.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Section 7. Gas Piping Technology Committee (GPTC) Acceptability of Standard Methods for Estimating Remaining Strength for Pipe Operating at 80% SMYS, October 2006 PHMSA Gas Transmission Integrity Management FAQs: 67 The rule requires that an operator temporarily reduce pressure if an immediate repair condition is discovered (192.933(d)(1)). Can the temporary reduction in operating pressure be based upon previous maximum allowable operating pressures? 69 Is a 20 percent reduction in pressure an adequate interim measure for immediate repair conditions? 134 How soon must I reduce pressure after identifying an immediate repair condition? 215 ASME B31.8S states that Immediate conditions shall be examined within five days after determination of the condition. Is this 5 day requirement part of the Final Rule? 229 Must I include a safety factor when calculating an acceptable reduced operating pressure [per 192.933(d)(1)] for the interim period until immediate conditions can be repaired?

Guidance Information	1. Operators can delay examination of an immediate defect beyond 5 days, as required by ASME B31.8S-2004, Section 7.2.1, but must document the basis for their conclusion that any delay will not impact pipeline safety. Operators must notify PHMSA of their inability to examine an immediate repair condition in five days if they cannot provide safety by reducing pressure or taking other action (see §192.933(a)). 2. Operators need not notify PHMSA, in accordance with 192.933(a), if they have reduced pressure or taken other action, even if examination is delayed beyond 5 days. However, unrepaired defects may result in the need to file a safety related condition report. Failure to submit required safety condition reports should be cited under §191.23 or §191.25. 3. When a State regulates the pipeline facility at issue, the State pipeline safety authority must be notified when the operator cannot meet a required remediation schedule and also cannot respond to that failure by either reducing pressure or taking another action to ensure safety of the pipeline. The operator's IM procedures must address notification requirements in this instance and provide the contact information. 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 5. Selected Final Orders Referencing §192.933(a): a) **Columbia Gas Transmission Corp., [3-2009-1018], (November 16, 2010), Item 1A,** Operator failed to either take prompt action to address all anomalous conditions discovered through integrity assessments or reduce operating pressure. b) **El Paso Natural Gas Co., [4-2007-1007], (March 10, 2011), Item 4,** Operator failed to take prompt action to address two anomalous conditions on the 2nd North Main of the Southern Natural Gas Pipeline System. Specifically, the operator failed to take action at MP 188-45+00 (74% wall loss) and MP 190-49+31 (70% wall loss).
Examples of a Probable Violation or Inadequate Procedures	1. Failure to take prompt action to address all anomalous conditions discovered through the integrity assessment. 2. IM plan/procedures did not define the term "prompt" as it relates to the need for temporary or long term pressure reduction. 3. Failure to take the required pressure reduction using RSTRENG, B31G, or 80% of the operating pressure at the time of discovery. 4. Failure to evaluate all anomalous conditions and remediate those that could reduce the pipeline integrity. 5. No documentation that the remediation of a condition will ensure that the condition would not pose a threat to the integrity of the pipeline until the next reassessment is performed. 6. Integrity management plan did not include provisions for both temporary and long-term pressure reductions. 7. The process/procedures did not require that a temporary pressure reduction or other action that ensures safety of the covered segment be implemented in the event that the operator is unable to respond within the timeframes required by 192.933.

	8. Process/procedures did not specify an acceptable method for determining the appropriate pressure reduction. 9. Process/procedures did not require that a technical justification be documented when a pressure reduction is in place for greater than 365 days. 10. Process/procedures did not require PHMSA and State regulatory authorities (if applicable) be notified when remediation schedules cannot be met and a temporary pressure reduction cannot be implemented or the pressure reduction exceeds 365 days. 11. The appropriate pressure reduction for an immediate repair anomaly was not determined and implemented. 12. A pressure reduction was implemented for greater than 365 days without a technical justification. 13. Failure to meet requirements for assuring safety (through a pressure reduction or other means) and documenting a technical justification, when remediation was not completed within required timeframes. 14. Failure to notify PHMSA and State regulatory authorities (if applicable) when remediation activities were not completed within 192.933 timeframes, and safety was not provided through a temporary pressure reduction or other action that ensures the safety of the covered segment or when a pressure reduction exceeds 365 days. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. Date of discovery. 4. Documentation of pressure reductions. 5. SCADA or other pressure records. 6. Documentation of actions taken to ensure safety and pipeline integrity. 7. Records. 8. Safety related condition reports. 9. Notifications to PHMSA and/or State agency. 10. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the remediation process and actions taken to ensure safety.
Other Special Notations	For those instances where a safety related condition would also be required to be filed, refer to 191.25, Filing safety-related condition reports.

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.933(b) & (c)
Section Title	What actions must be taken to address integrity issues?
Existing Code Language	(b) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. (c) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-104, 72 FR 39012, 17 July, 2007
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-05-04** **Integrity Management Notifications for Gas Transmission Lines** Current regulations require operators to notify OPS and state pipeline safety agencies of certain events related to integrity management programs for gas transmission lines. This bulletin provides guidance on notifying OPS and state agencies and describes OPS' review of notifications. OPS expects this bulletin to improve the efficiency of the notification and review process.

Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Section 7. Gas Piping Technology Committee (GPTC) Supplemental Guidance Appendix E.01, White Paper, Discovery of Condition Date. PHMSA Gas Transmission Integrity Management FAQs: 34 For purposes of establishing the deadlines for completing baseline assessments, what is the date on which an assessment is considered complete? 56 Do the anomaly repair schedule requirements in 192.933(d) apply to all previous internal inspection runs performed by the operator, or just the integrity assessments required by Subpart O (i.e., the baseline assessment and subsequent integrity assessments)? 58 What constitutes "discovery of a condition"? 62 When must monitored conditions be repaired? 66 If a covered segment 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 192.933 apply to the covered segment or the entire distance over which the pig is run? 68 Must tool accuracy be considered when determining if an anomaly detected by in-line inspection meets repair criteria? 70 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? 224 What actions must I take on non-covered segments if I find corrosion during an assessment of segments in HCA? 229 Must I include a safety factor when calculating an acceptable reduced operating pressure [per 192.933(d)(1)] for the interim period until immediate conditions can be repaired? 232 What timeframes apply to "discovery" of conditions presenting a potential threat to the integrity of a pipeline when using Direct Assessment? 241 May I exclude metal loss indications of >80% wall loss from immediate repair requirements per 933(d)(1), if B31G or RSTRENG predict a failure pressure of greater than 1.1 times MAOP?
Guidance Information	1. The preamble to the Federal Register Notice notes that it is important to know when a condition has been ‘‘discovered’’, because the time periods for remediation begin upon discovery. *Discovery of condition. It is important to know when a condition has been‘‘discovered’’, because the time periods for remediation begin upon discovery.* (Federal Register / Vol. 68, No. 240 / Monday, December 15, 2003 / Rules and Regulations at Page 69807.)

	2. Discovery of a condition requiring remediation occurs when an operator has sufficient information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. This point in time can vary, depending on specific circumstances; however, anomalies representing immediate threats to pipeline integrity must be discovered as soon as practicable. Discovery should not routinely and consistently occur near the end of the mandatory 180 day discovery deadline. 3. When using ILI, the beginning of the 180 days is considered to be the date that the ILI tool is pulled from the trap on a "good run". This date should be documented. 4. A schedule is to be established for remediation of anomalous conditions based on the importance of the threat to pipeline integrity. The priority of remediation activities within this schedule should be identified and the schedule should meet the time frame criteria discussed in §192.933(d). Concerns with the prioritization of an anomaly would be cited under §192.933(d). 5. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 6. Selected Final Orders Referencing §192.933(b) & (c): a) **Columbia Gas Transmission Corp., [3-2009-1018], (November 16, 2010), Item 1A,** Operator failed to promptly assess available information and make a determination that a condition was a potential threat to the integrity of the pipeline. Specifically, the operator did not promptly determine that an immediate repair condition existed on the VB LOOP following a June 29, 2004 internal inspection even though the final report was made available to the operator on August 8, 2004 and contained sufficient information to make that determination.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to document the criteria for discovery. 2. Failure to document the date of discovery. 3. Failure to develop or implement a schedule that prioritizes the evaluation and remediation of anomalous conditions. 4. Integrity management plan did not require the elements of 192.913(b) be met prior to implementing deviations from the repair timeframes by demonstrating exceptional performance. 5. Failure to take actions necessary to ensure the operator's ILI vendors provide timely information to enable discovery, e.g., specify requirements in ILI vendor contracts to support timely discovery of defects after ILI data is available. 6. Failure to require the examination of immediate conditions be conducted within 5 days of discovery if pressure reduction or other means to assure safety is not taken. 7. Failure to document the safety basis for delay of immediate condition repairs beyond five days. 8. Failure to develop process/procedures that required the development of a technical justification when a remediation activity cannot be completed within established timeframe requirements.

	9. Failure to establish a prioritized schedule for evaluation and remediation of anomalies. 10. Failure to promptly obtain sufficient information about conditions on the pipeline after conducting an integrity assessment. 11. Discovery was not documented promptly within 180 days of completion of an assessment, nor was it documented that compliance with the 180-day requirement was impracticable. 12. An anomaly was not remediated as required. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. Records. a. ILI Reports (both preliminary and final with dates when received) b. Direct Assessment results c. Review of assessment results and the discovery of anomalies and their timeliness d. Dates of discovery e. Nature (type) and size of anomalies f. "Dig lists" g. The operator's remediation schedule h. Actions taken to repair or otherwise remediate discovered conditions i. Repair records j. Operating logs or other documentation demonstrating that pressure reductions were promptly taken in response to the discovery of immediate conditions or in response to remediation schedules extending beyond those specified in the rule or the Supplement. k. The evaluation and remediation steps taken for anomalous conditions, l. The documented justification for continuing a pressure reduction beyond 365 days, and m. Documents indicating when a remediation activity has been completed. 4. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding discovery and prioritization and remediation scheduling of anomalous conditions.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.933(d)
Section Title	What actions must be taken to address integrity issues?
Existing Code Language	(d) Special requirements for scheduling remediation.- (1) <u>Immediate repair conditions.</u> An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions: (i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192. (ii) A dent that has any indication of metal loss, cracking or a stress riser. (iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action. (2) <u>One-year conditions</u>. Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition: (i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12). (ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld. (3) <u>Monitored conditions</u>. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation: (i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

	(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded. (iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-104, 72 FR 39012, 17 July, 2007
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Section 7. Gas Piping Technology Committee (GPTC) Understanding Magnetic Flux Leakage (MFL) Signals from Mechanical Damage in Pipelines - Phase I, September 18, 2007. Supplemental Guidance Appendix E.02, Integrated Analysis of Assessment Results. PHMSA Gas Transmission Integrity Management FAQs: 56 Do the anomaly repair schedule requirements in 192.933(d) apply to all previous internal inspection runs performed by the operator, or just the integrity assessments required by Subpart O (i.e., the baseline assessment and subsequent integrity assessments)? 62 When must monitored conditions be repaired? 66 If a covered segment 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 192.933 apply to the covered segment or the entire distance over which the pig is run? 68 Must tool accuracy be considered when determining if an anomaly detected by in-line inspection meets repair criteria? 69 Is a 20 percent reduction in pressure an adequate interim measure for immediate repair conditions?

	70 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? 134 How soon must I reduce pressure after identifying an immediate repair condition? 215 ASME B31.8S states that Immediate conditions shall be examined within five days after determination of the condition. Is this 5 day requirement part of the Final Rule? 224 What actions must I take on non-covered segments if I find corrosion during an assessment of segments in HCA? 225 Must I fix anomalies found in non-covered segments? 232 What timeframes apply to "discovery" of conditions presenting a potential threat to the integrity of a pipeline when using Direct Assessment? 241 May I exclude metal loss indications of >80% wall loss from immediate repair requirements per 933(d)(1), if B31G or RSTRENG predict a failure pressure of greater than 1.1 times MAOP?
Guidance Information	1. The special criteria for immediate repair conditions as defined by §192.933(d)(1)(i-iii) and ASME B31.8S-2004, Section 7.2.1, ASME B31.8S-2004, Section 7.2.2, and ASME B31.8S-2004, Section 7.2.3 are as follows: a) Where the predicted failure pressure is less than or equal to 1.1 times MAOP. b) Where there is a dent with accompanying metal loss, cracking, or a stress riser. c) Where engineering judgment by technical evaluators or management indicate that the condition must be immediately dealt with. d) Where metal loss is present on the longitudinal seam of low frequency ERW or lap welded pipe. e) Where there is any indication of Stress Corrosion Cracking, or f) Where there is any indication that the condition might result in rupture of the pipeline and require immediate action. 2. A failure to temporarily reduce operating pressure or shut down the pipeline until remediation of immediate repair conditions is completed should be cited under §192.933(a) rather than §192.933(d). 3. The special criteria for one-year repair conditions found in §192.933(d)(2)(i-ii) are as follows: a) Smooth dents on the upper 2/3 of the pipeline (between the 8 o'clock and 4 o'clock position) that have a depth that is greater than 6% of the pipeline's diameter. The depth criteria is 0.5 inches for pipeline with a Nominal Pipe Size less than 12 inches. b) Any dent having a depth greater than 2% of the pipeline's diameter that affects curvature at a longitudinal seam weld or a girth weld. The depth criteria is 0.25 inches for pipeline with a Nominal Pipe Size less than 12 inches. 4. Monitored conditions do not require repair upon discovery, but it is expected that the operator will have produced some means of tracking these conditions to facilitate review at the next risk assessment or integrity assessment. The

	following criteria from §192.933(d)(3) is used in designating monitored conditions: a) A dent on the lower 1/3 of the pipe (between the 4 o'clock and 8 o'clock positions) having a depth greater than 6% of the pipeline's diameter. The depth criteria is 0.5 inches for pipeline with a Nominal Pipe Size less than 12 inches. b) A dent on the upper 2/3 of the pipe (between the 8 o'clock and 4 o'clock positions) having a depth greater than 6% of the pipeline's diameter, but for which engineering analysis concludes that critical strain levels are not exceeded. The analysis must be documented. The depth criteria is 0.5 inches for pipeline with a Nominal Pipe Size of less than 12 inches. c) A dent with a depth greater than 2% of the pipeline's diameter that affects curvature at a girth weld or a longitudinal seam weld, but for which engineering analysis concludes that critical strain levels are not exceeded. The analysis must be documented. The depth criteria is 0.25 inches for pipeline with a Nominal Pipe Size of less than 12 inches. 5. A failure to develop a schedule for evaluation and remediation of anomalies should be cited under §192.933(c). The failure to characterize an anomaly as an immediate, one-year, or monitored condition would be cited under this section - §192.933(d). 6. ASME B31.8S-2004, Section 7, lists scheduled repairs that may need to be remediated. 7. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 8. Selected Final Orders referencing 192.933(d): a) **Gulf South PipelineCompny, LP, [4-2013-1011], (July 26, 2013), Item 1,** Operator failed to immediately repair two anomalies having an indication of metal loss. Specifically, the Notice alleges that Gulf South conducted two In Line Inspections assessments of its pipeline, located at HCA 600 and HCA 1082. Reports from the assessments were provided to Gulf South on July 8, 2009, and June 27, 2011, respectively. Each report identified an anomaly described as a "deformation… w/ Possible Metal Loss," which meets the definition of an immediate repair condition per §192.933(d)(1)(ii). Gulf South's integrity manager improperly reclassified both anomalies as "not immediate repair conditions." Ultimately, the repairs for the HCA 600 anomaly were completed March 3, 2010, and the HCA 1082 anomaly was repaired on July 21, 2011. Again, pursuant to §192.933(d), the repairs should have been made immediately after they were identified.
Examples of a Probable Violation or Inadequate Procedures	1. Integrity management plan did not identify the criteria for identification of conditions that present a potential threat to the integrity of the pipeline segment. 2. Failure to establish a program for the classification and remediation of anomalies that meet the criteria for: (1) Immediate repair conditions; (2) One-year conditions; (3) Monitored conditions; or (4) Scheduled repairs as specified in ASME B31.8S-2004, Section 7.

	3. Failure to classify an anomaly that meets the criteria for: (1) Immediate repair conditions; (2) One-year conditions; (3) Monitored conditions; or (4) Scheduled repairs as specified in ASME B31.8S-2004, Section 7. 4. Failure to specify requirements to record and monitor anomalies that are classified as "monitored conditions". 5. Failure to establish/implement process/procedures that documented requirements for classifying and remediating anomalies. 6. Failure to re-evaluate the nature of a "monitored condition" during the next integrity assessment. 7. Failure to specify requirements to classify and categorize anomalies per 192.933, including consideration of tool tolerance. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. ASME B31G, modified B31G, or RSTRENG calculations. 4. Pressure records showing operating pressure at the time of discovery. 5. Records. 6. Vendor reports. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding categorization of anomalous conditions.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.935(a)
Section Title	What additional preventive and mitigative measures must an operator take?
Existing Code Language	(a) General requirements. An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 75 FR 48593, August 11, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-11-01** **Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation.** PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities of their responsibilities, under Federal integrity management (IM) regulations, to perform detailed threat and risk analyses that integrate accurate data and information from their entire pipeline system, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP), and to utilize these risk analyses in the identification of appropriate assessment methods, and preventive and mitigative measures.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Section 2.2, 5, 7.

	Gas Piping Technology Committee (GPTC) Part 192 Appendix E. Supplemental Guidance Appendix H.01, Risk Analysis Application Examples. Supplemental Guidance Appendix H.02, Use of Remote Controlled Mainline Valves. Supplemental Guidance Appendix H.06, Corrosion Control Adequacy Test Flowchart. PHMSA Gas Transmission Integrity Management FAQs: 90 When must operators implement additional preventive and mitigative measures? For example, how long after completing the baseline assessment for a segment can an operator take to conduct a risk analysis and determine whether additional preventive or mitigative actions are needed (including the need for ASVs/RCVs)? If an operator determines that additional actions are warranted, how long does it have to implement them? 91 How do operators assess and control risk caused by third-parties over which they have no direct control? 135 Must I consider segments not in HCAs when evaluating my pipeline after discovering corrosion in a covered segment? 180 How will OPS evaluate required "enhancements" for operators that are already operating at high level with respect to damage prevention measures?
Guidance Information	1. The preamble to the Federal Register Notice makes it clear that P&M measures should not be limited to the examples in §192.935. *Examples of additional measures listed in the rule are: installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.* ***These are not the only measures an operator should consider or use.*** (Federal Register / Vol. 68, No. 240 / Monday, December 15, 2003 / Rules and Regulations at Page 69808.) 2. An operator may have a different process for making decisions about the implementation of additional preventive and mitigative actions. Some operators may make use of a formalized "decision model" for their evaluation, while others may use a more informal process based on general considerations. Whatever method is used, the use of a risk analysis is required, and should be reflected in the process that is used for evaluating potential preventive and mitigative measures.

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3. Implementation of processes to identify additional preventive and mitigative measures requires the identification of threats using a risk analysis. Concerns identified with the threat identification or the risk assessment used to identify additional preventive and mitigative measures should be cited under §192.917 rather than §192.935(a).
4. The failure to consider identified threats or use the risk analysis in the decision process for determining which additional preventive and mitigative measures will be implemented would be cited under §192.935(a).
5. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
6. Selected Final Orders Referencing §192.935(a):
   a) **Carolina Gas Transmission Corp., [2-2007-1010], (July 15, 2010), Item 3B,** Operator failed to take additional measures to prevent pipeline failures and to mitigate their consequences.
   b) **Indiana Gas Co. Inc., [2-2007-1014], (July 15, 2010), Item 5A,** Operator failed to take additional measures to prevent a pipeline failure and to mitigate the consequences of a failure.
   c) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 19,** Operator failed to evaluate several HCA segments to identify appropriate and required P&M measures.
   d) **West Texas Gas Inc., [4-2011-1007], (April 24, 2012), Item 1,** Operator failed to conduct a risk analysis of its pipeline to identify additional measures to protect high consequence areas and enhance public safety. Specifically, the operator was unable to identify any measures or actions that it took to satisfy Article 10 of its IMP.
   e) **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 11A,** Operator failed to take additional measures beyond those already required by Part 192 to prevent pipeline failures and to mitigate the consequence of those failures. Specifically, it alleged the operator failed to take P&M measures required by its own procedures.
   f) **Chevron Pipe Line Co., [5-2007-1007], (June 15, 2009), Item 2A,** Operator failed to adequately identify the additional P&M measures needed to prevent and mitigate the effects of a pipeline failure in an HCA. P&M measures identified for the Chalmette pipeline to prevent and mitigate mechanical damage were not documented in its computerized tracking system. Further, the operator did not know if the Chalmette P&M measures were ever approved or implemented.

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Examples of a Probable Violation or Inadequate Procedures

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1. Failure to consider, where applicable, time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking; static or residual threats such as third party damage and outside force damage; human error; and interactive threats. (ASME B31.8S-2004 Section 5.10)
2. Failure to consider the specific P&M measures listed in 192.935.
3. Failure to base the additional measures on the threats the operator has identified to each pipeline segment.
4. Failure to identify the need for additional preventive and mitigative measures in a timely manner.

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	5. Failure to document a schedule for implementing P&M measures. 6. Failure to implement protective measures that the risk analysis indicated. 7. Failure to use the risk analysis in the process that is used for evaluating potential preventive and mitigative measures. 8. Failure to consider other preventive or mitigative measures not specifically referenced by the Rule. 9. Failure to consider a variety of options that are a necessity as reinforced by ASME B31.8S-2004, Section 5.11 10. Additional measures taken were not commensurate with the nature and severity of the threat that has been identified. 11. Failure to consider both the likelihood and consequences of pipeline failures in the determination of needed additional preventive and mitigative measures. 12. Failure to determine if additional actions have been evaluated for the highest risk segments. 13. Failure to assess both physical and non-physical types of additional preventive and mitigative measures. 14. Failure to take additional measures beyond those already in Part 192. 15. Failure to implement preventive and mitigative measures that have the greatest impact on reducing risk. 16. Failure to conduct a thorough analysis to determine P&M measures for threats identified in the risk analysis for each pipeline segment. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Preventive and mitigative measures identified for implementation. 3. Schedule for implementing P&M measures. 4. Documentation demonstrating implementation. 5. Documentation or justification for the use or non-use of preventive and mitigative measures. 6. Threats for segments where P&M measures have been identified. 7. Records. 8. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding the identification of additional preventive and mitigated measures.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.935(b)
Section Title	What additional preventive and mitigative measures must an operator take?
Existing Code Language	(b) Third party damage and outside force damage- (1) Third party damage. An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum- (i) Using qualified personnel (see §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. (ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non-covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 191. (iii) Participating in one-call systems in locations where covered segments are present. (iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502-2008 (incorporated by reference, see §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination. (2) Outside force damage. If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 75 FR 48593, August 11, 2010

Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-13-04** **T.D. Williamson, Inc. Leak Repair Clamp Recall** **June 17, 2013** PHMSA advisory to alert all pipeline operators of a T.D. Williamson, Inc. (TDW) Leak Repair Clamp (LRC) recall issued by TDW on June 17, 2013. The recall covers all TDW LRCs of any pressure class and any size. The LRCs may develop a dangerous leak due to a defective seal. Hazardous liquid and natural gas pipeline operators should verify if they have any TDW LRCs subject to the recall by reviewing their records and equipment for installation of these LRCs. **Advisory Bulletin ADB-13-02** **Potential for Damage to Pipeline Facilities Caused by Flooding** PHMSA is issuing this advisory bulletin to all owners and operators of gas and hazardous liquid pipelines to communicate the potential for damage to pipeline facilities caused by severe flooding. This advisory includes actions that operators should consider taking to ensure the integrity of pipelines in case of flooding. **Advisory Bulletin ADB-11-05** **Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes** PHMSA is issuing this advisory bulletin to remind owners and operators of gas and hazardous liquid pipelines of the potential for damage to pipeline facilities caused by the passage of Hurricanes. **Advisory Bulletin ADB-11-04** **Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding** PHMSA is issuing this advisory bulletin to all owners and operators of gas and hazardous liquid pipelines to communicate the potential for damage to pipeline facilities caused by severe flooding. This advisory includes actions that operators should consider taking to ensure the integrity of pipelines in case of flooding.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Section 2.2, 5, 7. Gas Piping Technology Committee (GPTC)

	Part 192 Appendix E. Supplemental Guidance Appendix B.07, White Paper, Assessing for Third Party Damage. PHMSA Gas Transmission Integrity Management FAQs: 91 How do operators assess and control risk caused by third-parties over which they have no direct control? 113 Section 192.935(b)(2) uses the term "determines ... is a threat to the integrity of a covered segment." What is intended by the word "threat" in this context, such that the subsequent actions (e.g., relocating the line) are required to be implemented? 180 How will OPS evaluate required "enhancements" for operators that are already operating at high level with respect to damage prevention measures?
Guidance Information	1. Operators are required to have a written damage prevention program that meets the requirements of §192.614. The integrity management portion of this regulation requires that this program be enhanced to include additional requirements to provide preventive and mitigative measures for the pipeline as they relate to third party damage. 2. An operator must have procedures to determine if outside forces are a credible threat to their pipeline i.e., land movement, floods, sinkholes, high or low water levels, etc which may require preventive and mitigative measures. 3. An operator should use NPMS and other sources for information on geographic areas with the potential for certain external threats such as high or medium risk of floods, landslides, earthquakes, or hurricanes. 4. Qualified operator personnel are required for work that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. Concerns with the qualification (records, knowledge, experience, etc.) of personnel should be cited under 195 Subpart N with §192.915 listed as a secondary reference while a failure to use qualified personnel or a failure to require the use of qualified personnel in program documents would be cited under §192.935(b). 5. As part of the comprehensive risk analysis required by §192.917(c), operators are to determine the risk associated with third party damage to pipeline segments that may affect an HCA, and take comprehensive additional preventive measures. Concerns with the risk analysis and how it assesses the risk to third party damage should be cited under §192.917(c). 6. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 7. Selected Final Orders Referencing §192.935(b): a. **Carolina Gas Transmission Corp., [2-2007-1010], (July 15, 2010), Item 3A,** Operator failed to include enhanced measures in its damage prevention program for collecting location-specific information on excavation damage that had occurred in covered and non-covered pipeline segments. b.

Examples of a Probable Violation or Inadequate Procedures	1. Failure to follow procedures that address the threats of third party damage and outside force damage as required. 2. Failure to implement protective measures that the risk analysis indicated. 3. Failure to consider other preventive or mitigative measures not specifically referenced by the Rule. 4. Failure to take effective preventive actions to reduce the susceptibility of future Third Party Damage. 5. The operator did not review the implementation of the data integration process to determine if third party damage was identified as a threat to covered pipeline segments. 6. Failure to implement comprehensive additional preventive measures for identified third party damage risks. 7. Failure to have a decision making process to determine what preventive measures should be taken such as increased patrol frequency, improved public communication and awareness, and additional pipeline location markers. 8. Failure to participate in a one-call system in locations where covered segments are present. 9. Failure to identify excavations that should have been monitored per their procedures. 10. Enhanced damage prevention program did not provide for monitoring of excavations conducted on covered pipeline segments by pipeline personnel. 11. Failure to excavate the area near an encroachment or conduct an above ground survey using methods defined in NACE SP0502–2008, when physical evidence of encroachment involving excavation is found. 12. Failure to excavate and remediate indications of coating holidays or discontinuity warranting direct examination. 13. Failure to have additional measures that were commensurate with the nature and severity of the threat that has been identified. 14. Failure to determine if outside forces (e.g., earth movement, floods, and unstable suspension bridge) are a threat to the integrity of a covered segment. 15. Failure to determine if the frequency of aerial, foot or other methods of patrols should be increased, the addition of external protection , reducing external stress, or relocating the line were needed. 16. Failure to implement P&M measures required by the IM Plan. 17. Failure to minimize potential consequences to the covered segments that were susceptible to outside force damage. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Damage prevention program. 3. Qualification records. 4. Leak/failure reports relating to third party damage and outside force damage. 5. Incident reports. 6. Excavation activities. 7. One call notifications. 8. Patrolling and pipeline inspection records. 9. Records. 10. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding the damage prevention program.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.935(c)
Section Title	What additional preventive and mitigative measures must an operator take?
Existing Code Language	(c) Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors--swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 75 FR 48593, August 11, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Gas Piping Technology Committee (GPTC) PHMSA Technical Report, Remotely Controlled Valves on Interstate Natural Gas Pipelines, September 1999 PHMSA Technical Report, Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety, October 31, 2012 Supplemental Guidance Appendix H.02, Use of Remote Controlled Mainline Valves. PHMSA Gas Transmission Integrity Management FAQ: 86 What criteria must an operator use in determining whether automatic shut-off valves or remote control valves are required to protect HCAs? 90 When must operators implement additional preventive and mitigative measures? For example, how long after completing the baseline assessment for a segment can an operator take to conduct a risk analysis and determine whether additional preventive or mitigative actions are needed (including the need for ASVs/RCVs)? If an operator determines that additional actions are warranted, how long does it have to implement them?

Guidance Information	1. Each operator's IMP should include a risk analysis-based process describing methodology for determining if an automatic shut-off valve or remote control valve should be added. As a minimum the specified factors of 192.935(c) must be included. An operator should use the October, 2012 RCV study to determine appropriate ASV and RCV P&M measures.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to have preventive and mitigate procedures that requires a detailed analysis of the factors specified in 192.935(c). 2. Failure to follow procedures for the analysis of the use of the ASVs and/or RCVs. 3. Failure to have a risk analysis-based process describing methodology for determining if an automatic shut-off valve or remote control valve should be added. 4. Failure to consider all the required data for determining the need for automatic shut-off valve or remote control valves. 5. Failure to technically justify the conclusions on the need for, or lack of need for, the installation of automatic shut-off valves or remote control valves. 6. Failure to install an ASV or RCV after determining that it would be an effective means to protect an HCA in the event of a gas release. 7. Failure to document the reasons why a system-wide or generic study for RCVs/ACVs is applicable to a segment-specific condition. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Risk based analysis for use of ASVs or RCVs. 3. Justifications for using/not using ASVs or RCVs. 4. The factors for determining the use of ASVs or RCVs. 5. Records. 6. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding the use of, or decisions to not use ASVs or RCVs.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.935(d)
Section Title	What additional preventive and mitigative measures must an operator take?
Existing Code Language	(d) Pipelines operating below 30% SMYS. An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section (1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and (2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred. (3) Perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 75 FR 48593, August 11, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	Gas Piping Technology Committee (GPTC) NACE SP0502-2008, Pipeline External Corrosion Direct Assessment Methodology. PHMSA Gas Transmission Integrity Management FAQs: 91 How do operators assess and control risk caused by third-parties over which they have no direct control? 113 Section 192.935(b)(2) uses the term "determines ... is a threat to the integrity of a covered segment." What is intended by the word "threat" in this context, such that the subsequent actions (e.g., relocating the line) are required to be

	implemented? 149 Must an operator treat all of its class 3 and 4 areas as high consequence areas? 150 What requirements must an operator meet if there are no high consequence areas on any of its transmission pipelines? 180 How will OPS evaluate required "enhancements" for operators that are already operating at high level with respect to damage prevention measures? 230 What is the maximum interval for "semi-annual" and "quarterly" leak surveys (192.935(d)(3))?
Guidance Information	1. This section of the Integrity Management regulation (paragraph d) applies to pipelines operating below 30% SMYS that are not in an HCA but are in Class 3 or 4 locations. 2. An operator of a transmission pipeline operating below 30% SMYS located in a high consequence or in Class 3 or Class 4 location must follow the requirements in paragraphs §192.935(d)(1) - use of qualified personnel for covered activities such as marking, locating, and direct supervision of known excavation work and the participation in a one-call system. A failure to meet these requirements should be cited under §192.935(d)(1) or 192.935(b)(1)(iii) for concerns with the one-call system.. 3. An operator of a transmission pipeline operating below 30% SMYS located in a high consequence or in a Class 3 or Class 4 location must follow the requirements in paragraphs §192.935(d)(2) - monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred. A failure to meet these requirements should be cited under §192.935(d)(2). 4. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 location, but not in a high consequence area, must follow the requirements in paragraphs §192.935(d)(3) - semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical). A failure to meet these requirements on a pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not an HCA should be cited under §192.935(d)(3). 5. Qualified personnel are required for work that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. Concerns with the qualification (records, knowledge, experience, etc.) of personnel should be cited under 192 Subpart N with §192.915 as a secondary reference while a failure to use qualified personnel or a failure to require the use of qualified personnel in program documents would be cited under §192.935(d)(1). 6. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 7. Procedures for meeting the requirements of 192.935(d) for pipelines operating below 30% SMYS not in an HCA but in a Class 3 or 4 location may be in the operator's O&M manual and not in an Integrity Management Plan.

	8. Table E.II.1 of 192 Appendix E provides guidance on P&M measures for transmission pipelines operating below 30% SMYS not in an HCA but in a Class 3 or 4 location. 9. Table E.II.3 of 192 Appendix E provides guidance on P&M measures for transmission pipelines operating below 30% SMYS in HCAs. 10. A follow up investigation of unmonitored or unreported construction activities may use the methods of NACE SP0502-2008.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to follow its procedures to implement the below 30% SMYS requirements. 2. Failure to take effective preventive actions to reduce the susceptibility of future Third Party Damage. 3. Failure to implement comprehensive additional preventive measures for identified third party damage risks. 4. Failure to have a decision making process to determine what preventive measures should be taken such as increased patrol frequency, improved public communication and awareness, and additional pipeline location markers. 5. For pipelines operating below 30% SMYS located in a high consequence area, failure to comply with third party damage requirements. 6. For pipelines operating below 30% SMYS located in a high consequence area, failure to verify that excavations near the pipeline are monitored, nor did the operator conduct patrols of the pipeline at bi-monthly intervals as required by §192.705. 7. For pipelines operating below 30% SMYS in a Class 3 or 4 location, but not in a high consequence area, failure to have third party damage requirements such as using qualified personnel for work that could adversely affect the integrity of a covered segment, including marking, locating, and direct supervision of known excavation work. 8. For pipelines operating below 30% SMYS in a Class 3 or 4 location, but not in a high consequence area, failure to monitor excavations near the pipeline or conduct patrols at bi-monthly intervals. 9. For pipelines operating below 30% SMYS in a Class 3 or 4 location, but not in a high consequence area, failure to perform semi-annual leak surveys (quarterly for unprotected pipe or cathodically protected pipe where electrical surveys are impractical) 10. Failure to identify excavations that should have been monitored per their procedures. 11. Failure to do a follow up investigation on an indication of unmonitored or unreported construction activity. 12. The enhanced damage prevention program did not provide for monitoring by qualified personnel of excavations conducted on covered pipeline segments. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. SMYS calculations for identified segments. 4. Excavation records. 5. Damage prevention program. 6. Patrolling records. 7. Leak survey records. 8. One call tickets/responses. 9. Records. 10. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of requirements for pipelines operating below 30% SMYS.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.935(e)
Section Title	What additional preventive and mitigative measures must an operator take?
Existing Code Language	(e) Plastic transmission pipeline. An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 75 FR 48593, August 11, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB -12-03** **Notice to Operators of Driscopipe 8000 High Density Polyethylene Pipe of the Potential for Material Degradation** On March 6, 2012, PHMSA issued this advisory bulletin to alert operators using Driscopipe® 8000 High Density Polyethylene Pipe (Drisco8000) of the potential for material degradation. Degradation has been identified on pipe between one-half inch to two inches in diameter that was installed between 1978 and 1999 in desert-like environments in the southwestern United States. However, since root causes of the degradation have not been determined, PHMSA cannot say with certainty that this issue is isolated to these regions, operating environments, pipe sizes, or pipe installation dates. While the manufacturer has attempted to communicate with known or suspected users, PHMSA and the National Association of Pipeline Safety Representatives (NAPSR) have identified several operators currently using Drisco 8000 pipe who had not received communications about the issue. PHMSA is issuing this advisory bulletin to all operators of Drisco 8000 pipe in an effort to ensure they are aware of the issue, communicating with the manufacturer and their respective regulatory authorities to determine if their systems are susceptible to similar degradation, and taking measures to address it.
Other Reference Material & Source	Gas Piping Technology Committee (GPTC) Part 192 Appendix E. PHMSA Gas Transmission Integrity Management FAQs: 91 How do operators assess and control risk caused by third-parties over which they have no direct control? 247 For plastic transmission pipeline, must I meet all of the requirements in the sections specified in section 192.901 or just those requirements specifically directed at plastic pipe?

Guidance Information	1. Qualified personnel for work that could adversely affect the integrity of a plastic pipe covered segment, such as marking, locating, and direct supervision of known excavation work. Concerns with the qualification (records, knowledge, experience, etc.) of personnel should be cited under 195 Subpart N with §192.915 provided as a secondary reference while a failure to use qualified personnel or a failure to require the use of qualified personnel in program documents would be cited under §192.935(e). 2. Participation in a one-call system is required for plastic pipe that is in a covered segment. 3. The damage prevention program for plastic pipe must provide for monitoring of excavations by qualified personnel conducted on covered pipeline segments. The program must specify that if an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, then the operator must perform a follow up investigation. 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to follow its procedures implementing the P&M Measures for plastic pipe. 2. Failure to not take effective preventive actions to reduce the susceptibility of a future Third Party Damage. 3. As part of the comprehensive risk analysis, failure to determine the risk associated with third party damage to pipeline segments that may affect an HCA. 4. Failure to take comprehensive additional preventive measures for plastic piping. 5. The operator did not, for third party damage risks identified, implement comprehensive additional preventive measures. 6. For plastic transmission lines, failure to have a process for compliance with third party damage requirements such as the use of qualified personnel consistent with the requirements of 192.915, the monitoring of excavations, and the requirement of excavation and remediation of any indication of damage that warrants direct examination. 7. Failure to participate in a one-call system in locations where covered segments are present. 8. Failure to identify excavations that should have been monitored per procedures. 9. The enhanced damage prevention program did not provide for monitoring of excavations conducted on covered pipeline segments by pipeline personnel. 10. Failure to excavate an area near an encroachment when physical evidence of encroachment involving excavation is found. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Pipeline inventory records. 3. Damage prevention program. 4. One call tickets. 5. Excavation activity records. 6. Patrolling records. 7. Records and maps. 8. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of requirements for plastic pipelines.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.937(a) & (b)
Section Title	What is a continual process of evaluation and assessment to maintain a pipeline's integrity?
Existing Code Language	(a) General. After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment. (b) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in §192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-13-04** **T.D. Williamson, Inc. Leak Repair Clamp Recall** **June 17, 2013** PHMSA advisory to alert all pipeline operators of a T.D. Williamson, Inc. (TDW) Leak Repair Clamp (LRC) recall issued by TDW on June 17, 2013. The recall covers all TDW LRCs of any pressure class and any size. The LRCs may develop a dangerous leak due to a defective seal. Hazardous liquid and natural gas pipeline operators should verify if they have any TDW LRCs subject to the recall by reviewing their records and equipment for installation of these LRCs.

Advisory Bulletin ADB-12-11

Reporting of Exceedances of Maximum Allowable Operating Pressure December 21, 2012

PHMSA is issuing this Advisory Bulletin to inform owners and operators of gas transmission pipelines that if the pipeline pressure exceeds maximum allowable operating pressure (MAOP) plus the build-up allowed for operation of pressure-limiting or control devices, the owner or operator must report the exceedance to PHMSA on or before the fifth day following the date on which the exceedance occurs. If the pipeline is subject to the regulatory authority of one of PHMSA¿s State Pipeline Safety Partners, the exceedance must also be reported to the applicable state agency.

Advisory Bulletin ADB-12-10

Pipeline Safety: Using Meaningful Metrics in Conducting Integrity Management Program Evaluations December 5, 2012

PHMSA is issuing an Advisory Bulletin to remind operators of gas transmission and hazardous liquid pipeline facilities of their responsibilities, under Federal integrity management regulations, to perform evaluations of their integrity management programs using meaningful performance metrics.

Advisory Bulletin ADB -12-03

Notice to Operators of Driscopipe 8000 High Density Polyethylene Pipe of the Potential for Material Degradation

On March 6, 2012, PHMSA issued this advisory bulletin to alert operators using Driscopipe® 8000 High Density Polyethylene Pipe (Drisco8000) of the potential for material degradation. Degradation has been identified on pipe between one-half inch to two inches in diameter that was installed between 1978 and 1999 in desert-like environments in the southwestern United States. However, since root causes of the degradation have not been determined, PHMSA cannot say with certainty that this issue is isolated to these regions, operating environments, pipe sizes, or pipe installation dates. While the manufacturer has attempted to communicate with known or suspected users, PHMSA and the National Association of Pipeline Safety Representatives (NAPSR) have identified several operators currently using Drisco 8000 pipe who had not received communications about the issue. PHMSA is issuing this advisory bulletin to all operators of Drisco 8000 pipe in an effort to ensure they are aware of the issue, communicating with the manufacturer and their respective regulatory authorities to determine if their systems are susceptible to similar degradation, and taking measures to address it.

	Advisory Bulletin ADB-05-04 **Integrity Management Notifications for Gas Transmission Lines** Current regulations require operators to notify OPS and state pipeline safety agencies of certain events related to integrity management programs for gas transmission lines. This bulletin provides guidance on notifying OPS and state agencies and describes OPS' review of notifications. OPS expects this bulletin to improve the efficiency of the notification and review process.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 5.8. 6. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008. Use of MFL Tools to Detect Hard Spots, Duckworth and Eiber, June 2004. Supplemental Guidance Appendix B.03, ILI Tool Characteristics and Attributes. Supplemental Guidance Appendix B.04, Typical Tool Selection Factors. Supplemental Guidance Appendix B.06, Hydrostatic Testing. Supplemental Guidance Appendix B.08, White Paper - Manufacturing and Construction Defects. Supplemental Guidance Appendix C.02, White Paper - Data Gathering and Interpretation. Supplemental Guidance Appendix C.04, Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects. Supplemental Guidance Appendix F.01, Continual Evaluation and Assessment. Supplemental Guidance Appendix F.03, Reassessment Intervals for Hydro-Tests Based on Pressure Cycle Defect Growth. Supplemental Guidance Appendix F.02, Reassessment Interval Determination Methods. Supplemental Guidance Appendix F.04, White Paper - CDA and Reassessment Intervals. Supplemental Guidance Appendix G.01, Calculating Re-assessment Interval. Supplemental Guidance Appendix L.01, White Paper - Continuing Improvement. PHMSA Gas Transmission Integrity Management FAQs: 40 How often must periodic integrity assessments be performed on HCA pipeline segments after the baseline assessment is completed? 81 What kinds of information must be integrated in performing a continual evaluation of pipeline integrity? 133 Must I do a full assessment every 7 years if my pipeline is subject to threats other than external and internal corrosion.

	205 Does an operator have to provide the original source documents for the covered segment of the pipeline? (Source document means actual pressure test chart for MAOP, mill test report on pipe, etc.) In the absence of original source material, will DOT accept inventory map data for pipeline information, MAOP database information, etc.? 207 Table 3 of ASME/ANSI B31.8S indicates that reassessment intervals must be 5 years for some instances in which test pressure was higher than would be required by Subpart J. If I conduct my assessments in accordance with Subpart J, must I reassess more frequently than once every seven years? 234 How often must my risk analysis be updated?
Guidance Information	1. Periodic evaluations and reassessments of covered segments must be performed after completing baseline integrity assessments. The frequency for conducting periodic evaluations and the reassessment interval should be based on risk factors specific to its pipeline, including at least the past and present integrity assessment results, risk analysis results, and decisions about repair, and preventive and mitigative actions taken to reduce risk. 2. Periodic "evaluations" involve a different process than "assessments." 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. Re-running the risk analysis does not meet the requirement for continual evaluation and assessment. 3. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. Concerns with the data integration or risk assessment process should be cited under §192.917. A failure to consider data integration or the risk assessment in periodic evaluations would be cited under §192.937(b). 4. Regardless of the "primary" reassessment method or the stress level of the pipe, there is a regulatory requirement that some type of reassessment must be performed on each covered segment, susceptible to external and internal corrosion, at intervals not to exceed 7 years. Reassessments for other pipeline threats are performed at the intervals in §192.939 depending on the SMYS of the pipeline. This reassessment can be a "primary" assessment method or an "interim" reassessment such as a CDA or a low stress reassessment. Concerns with established reassessment intervals should be cited under §192.939. 5. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 6. FAQ 234 conveys that a risk analysis should be updated annually. Information from a periodic evaluation provides updated information that needs to be input into the risk analysis. Therefore, it could be expected that periodic evaluations be performed annually. 7. Selected Final Orders Referencing §192.937(a) or (b): a) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 21,** Operator failed to have procedures and documentation requirements for

	performing periodic evaluations based on data integration and risk assessment of its entire pipeline. Specifically, the operator's IMP process for conducting periodic evaluations did not consider "past and present integrity assessment results, data integration, risk assessment information, decisions about remediation, and additional preventive and mitigative measures. b) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 22,** Operator failed to conduct periodic evaluations as frequently as needed to ensure the integrity of each pipeline segment. Specifically, the operator did not conduct the yearly evaluations required by its IMP for the baseline assessments reported as complete. c) **Gulf South Pipeline Co., [4-2007-1003], (November 2, 2011), Item 23,** Operator failed to have procedures and documentation requirements in place to use completed periodic evaluations to determine if new information warranted any change in reassessment intervals or methods. The operator's procedures do not ensure the thorough evaluation of assessment results. They also fail to include documentation requirements for the use of evaluations that have been conducted. d) **Air Products & Chemicals Inc., [4-2009-1008], (December 1, 2009), Item 1,** Operator failed to perform periodic evaluations as frequently as needed to ensure the integrity of each covered segment. Specifically, the operator could not provide any documentation during the PHMSA inspection to demonstrate that the company had performed periodic evaluations. e) **Praxair, Inc., [4-2009-1011], (June 17, 2010), Item 2,** Operator failed to conduct periodic evaluations as frequently as needed to ensure the integrity of each covered segment. Specifically, the operator could not provide any documentation during the PHMSA inspection to demonstrate that the company had performed periodic evaluations. f) **CPN Pipeline Co., [5-2007-1006], (December 16, 2009), Item 3,** Operator failed to conduct periodic evaluations of covered segments as frequently as needed to assure the integrity of each covered segment. Specifically, the operator failed to define an appropriate interval to ensure periodic integrity evaluations would be conducted as frequently as needed to ensure pipeline integrity.
Examples of a Probable Violation or Inadequate Procedures	1. A reassessment interval that exceeded the maximum values in 192.939 and/or Table 3 in B31.8S-2004 was specified. 2. Failure to follow procedures for conducting periodic evaluations and reassessments of covered segments after completing the baseline integrity assessment. 3. Procedures did not define the frequency of reviews and required documentation of the reviews. 4. Failure to base the frequency for conducting periodic evaluations and the reassessment interval on risk factors specific to its pipeline, including at least the past and present integrity assessment results, risk analysis results, and decisions about repair, and preventive and mitigative actions taken to reduce risk.

	5. Failure to use data from the entire pipeline and/or considered data only from covered segments which is not allowed. 6. The operator did not include in its periodic evaluations cyclic fatigue and other loading conditions (examples include ground movement, overburden, equipment loading, or suspension bridge condition) that could lead to failure or a deformation, including dent or gouge, or other defect in a covered segment. 7. Failure to conduct periodic integrity evaluations that are sufficiently rigorous for making integrity related decisions. 8. Failure to base the frequency of the evaluations on risk factors specific to its pipeline. 9. Failure to implement an immediate evaluation of the re-assessment interval (ASME B31.8S-2004, Table 3, Note 1) after a time-dependent failure. 10. Failure to have a process in place to identify those factors/events initiating an immediate evaluation of pipeline integrity. 11. Failure to take into account relevant changes to the pipeline system and/or verify that this new information was evaluated for potential impact on evaluation results (i.e., reassessment intervals and methods). *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Periodic evaluation documentation and results. 3. Documentation of actions taken (or not taken) as a result of periodic evaluations. 4. Operator records. 5. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding implementation of the periodic evaluation process.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.937(c)
Section Title	What is a continual process of evaluation and assessment to maintain a pipeline's integrity?
Existing Code Language	(c) Assessment methods. In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (see §192.917), or by confirmatory direct assessment under the conditions specified in §192.931. (1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment. (2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939. (3) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with as applicable, the requirements specified in §§192.925, 192.927 or 192.929; (4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. (5) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with §192.931.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	

Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-05-04** **Integrity Management Notifications for Gas Transmission Lines** Current regulations require operators to notify OPS and state pipeline safety agencies of certain events related to integrity management programs for gas transmission lines. This bulletin provides guidance on notifying OPS and state agencies and describes OPS' review of notifications. OPS expects this bulletin to improve the efficiency of the notification and review process.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 5.8. 6. Mechanical Damage in Pipelines, Michael Baker Jr. Inc., April 2009. Pipeline Corrosion, Final Report, Michael Baker Jr. Inc., November 2008 Use of MFL Tools to Detect Hard Spots, Duckworth and Eiber, June 2004. NACE RP 0102-2002, In-Line Inspection of Pipelines (not incorporated by reference). NACE SP 0502-2008, Pipeline External Corrosion Direct Assessment Methodology (incorporated by reference), NACE SP 0206-2006, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Gas (not incorporated by reference). NACE RP 0204-2004, Stress Corrosion Cracking Direct Assessment (not incorporated by reference). Supplemental Guidance Appendix B.01, Protocol Guidance for Baseline Assessment Plans. Supplemental Guidance Appendix B.03, ILI Tool Characteristics and Attributes. Supplemental Guidance Appendix B.04, Typical Tool Selection Factors. Supplemental Guidance Appendix B.06, Hydrostatic Testing. Supplemental Guidance Appendix B.08, White Paper - Manufacturing and Construction Defects. Supplemental Guidance Appendix C.02, White Paper - Data Gathering and Interpretation. Supplemental Guidance Appendix C.04, Monitoring and Assessment of Piping Subject to Manufacturing and Construction Defects. Supplemental Guidance Appendix F.01, Continual Evaluation and Assessment. Supplemental Guidance Appendix F.03, Reassessment Intervals for Hydro-Tests Based on Pressure Cycle Defect Growth. Supplemental Guidance Appendix F.02, Reassessment Interval Determination Methods.

	Supplemental Guidance Appendix F.04, White Paper - CDA and Reassessment Intervals. Supplemental Guidance Appendix G.01, Calculating Re-assessment Interval. Supplemental Guidance Appendix L.01, White Paper - Continuing Improvement. PHMSA Gas Transmission Integrity Management FAQs: 27 For reassessments using ILI, are verification digs required if the ILI tool does not show any defects/anomalies? 81 What kinds of information must be integrated in performing a continual evaluation of pipeline integrity? 133 Must I do a full assessment every 7 years if my pipeline is subject to threats other than external and internal corrosion? 141 A spike test can be very useful for assessing some threats, including seam issues. Can a spike test be used as an assessment method? 187 Discussion at the Houston workshop implied an operator needs to justify use of DA. Since DA is an accepted assessment method in the rule, why does an operator need to justify it over ILI or hydrotesting? 216 Assuming a system operating below 30% SMYS and reassessment every 20 years, how much of a system must be assessed via CDA at the 7 and 14 year intervals? How do we determine where we must use CDA? 228 Can the conduct of a successful CDA assessment extend the interval until the next required assessment using ILI, pressure testing, DA, or other technology?
Guidance Information	1. Reassessment methods should be selected based upon the threats to which a covered segment is susceptible. A failure to select assessment methods without a consideration of the threats should be cited under §192.937(c). Concerns with the identified threats or threat identification process should be cited under §192.917. 2. A spike test may be performed along with a pressure test meeting Subpart J requirements. In that case, the Subpart J test is considered the primary assessment, and no notification to PHMSA would be required. Use of a spike test, alone, as an assessment method would constitute "other technology" and requires notification to PHMSA (and/or a state regulator if applicable) at least 180 days in advance. A failure to meet notification requirements should be cited under §192.937(c)(4). 3. Confirmatory Direct Assessment is an "interim" integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment. There are numerous FAQs available on this topic. Concerns with the implementation of Confirmatory Direct Assessment should be cited under §192.931. 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.

Examples of a Probable Violation or Inadequate Procedures	1. Failure to follow their procedures for the establishment of assessment methods based on threats. 2. Determination of reassessment methods was not consistent with ASME B31.8S-2004, Section 6. 3. Direct Assessment was used to assess for threats other than external corrosion, internal corrosion, or stress corrosion cracking. Spike test used as a sole assessment without submittal of an "other technology" request to PHMSA. 4. Failure to properly implement confirmatory direct assessment. The reassessment method selected was not consistent with the requirements of the IMP and ASME B31.8S-2004, Section 6, based on the threats applicable to that segment. 5. Selection of an "other technology" without technical justification that the technology provided an equivalent understanding of the condition of the line pipe. 6. Failure to notify PHMSA regarding the use of "other technology." 7. Confirmatory direct assessment performed past the seven year reassessment time interval. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Schedule for conducting re-assessments. 3. Direct Assessment plan. 4. Vendor reports. 5. Pressure test reports. 6. Justification for the use of "other technology". 7. Copies of procedures used to perform "other technology". 8. Records. 9. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding reassessment methods.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.939(a)
Section Title	What are the required reassessment intervals?
Existing Code Language	An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments. (a) Pipelines operating at or above 30% SMYS. An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals. (1) Pressure test or internal inspection or other equivalent technology. An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by-- i) Basing the interval on the identified threats for the covered segment (see §192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by §192.917; or (ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME/ANSI B31.8S, section 5, Table 3. (2) External Corrosion Direct Assessment. An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502-2008 (incorporated by reference, see §192.7). (3) Internal Corrosion or SCC Direct Assessment. An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3. (i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;

	(ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and (iii) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size. MAXIMUM REASSESSMENT INTERVAL (see table below) (*) A Confirmatory direct assessment as described in §192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval. (**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 75 FR 48593, August 11, 2010
Interpretation Summaries	**Interpretation: WINDOT 192.939 1 Date: July 17, 2009** It was requested that PHMSA interpret the statutory seven-year gas pipeline integrity reassessment interval to allow reassessments to be conducted every seven calendar years not to exceed 90 months. Under 49 U.S.C. 60109(c)(3)(B), gas pipeline operators are required to periodically reassess the integrity of pipeline facilities covered by their integrity management programs "at a minimum of once every 7 years…". The implementing regulations at 49 CFR §192.939(a) require that reassessments and alternative methods of reassessments such as confirmatory direct assessments be conducted within the seven-year period after the previous assessment of a covered segment. This requirement is also reflected in a Frequently Asked Question available on PHMSA's website reprinted as FAQ 41. Therefore, the current requirement is seven actual years from the anniversary date of the last assessment of a covered segment.

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment.	10 years (*)	15 years (*)	20 years.(**)
Confirmatory Direct Assessment	7 years	7 years	7 years
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in §192.941

Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 5, and 6.2. Gas Piping Technology Committee (GPTC) PHMSA Gas Transmission Integrity Management FAQs: 28 What must an operator consider in prioritizing pipe segments for assessment and re-assessment? 40 How often must periodic integrity assessments be performed on HCA pipeline segments after the baseline assessment is completed? 41 Does the requirement that an operator establish inspection intervals not to exceed a specified number of years mean calendar years (i.e., pipe assessed in 2004 must be re-assessed during 2011) or actual years? 42 Must operators conduct re-assessments before they have completed all baseline assessments? 43 Can a re-assessment interval be extended beyond the maximum interval specified in 192.939? 45 Can the operator use risk assessment data to defend longer intervals between integrity assessments? 133 Must I do a full assessment every 7 years if my pipeline is subject to threats other than external and internal corrosion? 228 Can the conduct of a successful CDA assessment extend the interval until the next required assessment using ILI, pressure testing, DA, or other technology? 236 If I have hydrostatically tested my pipeline to a test pressure different than those listed in table 3 of ASME/ANSI B31.8S, how can I determine an extended reassessment interval?
Guidance Information	1. The operator's process should ensure that each covered segment is scheduled for a reassessment (if it has already had a baseline assessment), or that a reassessment be scheduled upon completion of the baseline assessment. 2. There is a regulatory requirement that some type of reassessment must be performed on each covered segment at intervals not to exceed 7 years. This reassessment can be a "primary" assessment method or an "interim" reassessment such as a CDA or a low stress reassessment. The interval "7 years" should be measured in actual years not calendar years. If deficiencies are noted with the CDA process, the concerns should be cited under §192.931. 3. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a	1. Failure to follow procedures for determining reassessment intervals. 2. Failure to establish reassessment intervals as required by 192.939.

Probable Violation or Inadequate Procedures	3. Reassessment interval exceeded the maximum intervals allowed in 192.939 and/or Table 3 in ASME B31.8S-2004. 4. Failure to consider the identified threats, results from the last integrity assessment, and a review of data integration and risk assessment in determining the reassessment interval. 5. Failure to establish an appropriate reassessment interval. 6. A reassessment was not scheduled for a segment within seven years after the baseline assessment 7. Inappropriate or improperly documented technical basis to support the interval selected. 8. Covered segments did not receive a reassessment within rule-required timeframes. 9. Reassessment not completed in accordance with the reassessment interval established in the IMP. 10. External corrosion direct assessment (ECDA) chosen as the assessment method, but reassessment interval not based on the NACE standard or the maximum value specified in ASME B31.8S-2004, Section 5, Table 3, whichever is shorter. 11. Internal corrosion direct assessment (ICDA) or stress corrosion cracking direct assessment (SCCDA) chosen, but reassessment interval not based on ½ the time for the largest remaining defect and the growth rate appropriate for the conditions where the largest remaining defect is the size of the largest defect discovered in the SCC or ICDA segment or the maximum value specified in ASME B31.8S-2004, Section 5, Table 3, whichever is shorter. 12. Extended reassessment interval selected based upon implementing exceptional performance programs per §192.913(b), but did not perform, or has not scheduled an "interim" reassessment, i.e. a CDA, within the 7-year requirement. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. Assessment and/or reassessment schedules. 4. SMYS calculations for covered segments. 5. Direct assessment reports. 6. Reassessment interval calculations. 7. Records. 8. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding the establishment of reassessment intervals.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.939(b)
Section Title	What are the required reassessment intervals?
Existing Code Language	An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments. (b) Pipelines Operating Below 30% SMYS. An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following-- (1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941. (2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section. (3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section. (4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with §192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval. (5) Reassessment by the low stress assessment method at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval. (6) The following table sets forth the maximum reassessment intervals. Also refer to Appendix E.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

	MAXIMUM REASSESSMENT INTERVAL

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment.	10 years (*)	15 years (*)	20 years.(**)
Confirmatory Direct Assessment	7 years	7 years	7 years
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in §192.941

(*) A Confirmatory direct assessment as described in §192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.
(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-114, 75 FR 48593, August 11, 2010
Interpretation Summaries	**Interpretation: WINDOT 192.939 1 Date: July 17, 2009** It was requested that PHMSA interpret the statutory seven-year gas pipeline integrity reassessment interval to allow reassessments to be conducted every seven calendar years not to exceed 90 months. Under 49 U.S.C. 60109(c)(3)(B), gas pipeline operators are required to periodically reassess the integrity of pipeline facilities covered by their integrity management programs "at a minimum of once every 7 years…". The implementing regulations at 49 CFR §192.939(a) require that reassessments and alternative methods of reassessments such as confirmatory direct assessments be conducted within the seven-year period after the previous assessment of a covered segment. This requirement is also reflected in a Frequently Asked Question available on PHMSA's website reprinted as FAQ 41. The current requirement is seven years from the anniversary date of the last assessment of a covered segment.

Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Sections 5, and 6.2. Gas Piping Technology Committee (GPTC) PHMSA Gas Transmission Integrity Management FAQs: 9 Does the rule apply to gathering and other low-stress lines? 28 What must an operator consider in prioritizing pipe segments for assessment and re-assessment? 40 How often must periodic integrity assessments be performed on HCA pipeline segments after the baseline assessment is completed? 41 Does the requirement that an operator establish inspection intervals not to exceed a specified number of years mean calendar years (i.e., pipe assessed in 2004 must be re-assessed during 2011) or actual years? 42 Must operators conduct re-assessments before they have completed all baseline assessments? 43 Can a re-assessment interval be extended beyond the maximum interval specified in 192.939? 45 Can the operator use risk assessment data to defend longer intervals between integrity assessments? 133 Must I do a full assessment every 7 years if my pipeline is subject to threats other than external and internal corrosion? 178 If a line was operating at <30% SMYS and reassessment schedules had been established based on this stress level, what requirements would need to be adopted before the line stress is raised to >30% SMYS? 207 Table 3 of ASME/ANSI B31.8S indicates that reassessment intervals must be 5 years for some instances in which test pressure was higher than would be required by Subpart J. If I conduct my assessments in accordance with Subpart J, must I reassess more frequently than once every seven years? 228 Can the conduct of a successful CDA assessment extend the interval until the next required assessment using ILI, pressure testing, DA, or other technology? 236 If I have hydrostatically tested my pipeline to a test pressure different than those listed in table 3 of ASME/ANSI B31.8S, how can I determine an extended reassessment interval?
Guidance Information	1. The operator's process should ensure that each covered segment is scheduled for a reassessment (if it has already had a baseline assessment), or that a reassessment be scheduled upon completion of the baseline assessment. 2. There is a regulatory requirement that some type of reassessment must be performed on each covered segment at intervals not to exceed 7 years. This reassessment can be a "primary" assessment method or an "interim"

	reassessment such as a CDA or a low stress reassessment. The interval "7 years" should be measured in actual years not calendar years. If deficiencies are noted with the CDA process, the concerns should be cited under §192.931. If deficiencies are noted with the low-stress assessment process, the concerns should be cited under §192.941 3. The rule requires that a baseline assessment must be completed on a segment before the low stress reassessment method can be performed. A failure to meet this requirement should be cited under §192.941 rather than §192.939(b). 4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
1. **Examples of a Probable Violation or Inadequate** Procedures	1. Reassessment interval exceeded the maximum values in 192.939 and/or Table 3 in B31.8S-2004. 2. Failure to consider identified threats, results from the last integrity assessment, and a review of data integration and risk assessment when determining the reassessment interval. 3. The appropriate reassessment interval was not determined and/or an appropriate technical basis was not developed and documented to support the interval selected. 4. One or more covered segments did not receive a reassessment within rule-required timeframes. 5. Reassessment not completed in accordance with the reassessment interval established in the IMP. 6. External corrosion direct assessment (ECDA) chosen as the assessment method, but did not base the reassessment interval on the NACE standard or the maximum value specified in ASME B31.8S-2004, Section 5, Table 3, whichever is shorter. 7. Internal corrosion direct assessment (ICDA) or stress corrosion cracking direct assessment (SCCDA) chosen, but did not base the reassessment interval on ½ the time for the largest remaining defect and the growth rate appropriate for the conditions where the largest remaining defect is the size of the largest defect discovered in the SCC or ICDA segment or the maximum value specified in ASME B31.8S-2004, Section 5, Table 3, whichever is shorter. 8. Extended reassessment interval selected based upon implementing exceptional performance programs, but did not perform or has not scheduled an "interim" reassessment, i.e. a CDA or low-stress reassessment, within the 7-year requirement. 9. Low-stress reassessment used on a covered pipeline segment that operated at or above 30%. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. Assessment and/or reassessment schedules. 4. SMYS calculations for covered segments. 5. Direct assessment reports. 6. Reassessment interval calculations. 7. Records. 8. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding low-stress reassessments.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.941(a)
Section Title	What is a low stress reassessment?
Existing Code Language	(a) General. An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with §192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§192.919 and 192.921.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. ANSI ASC Z380 Gas Piping Technology Committee (GPTC) PHMSA Gas Transmission Integrity Management FAQs: 9 Does the rule apply to gathering and other low-stress lines? 178 If a line was operating at <30% SMYS and reassessment schedules had been established based on this stress level, what requirements would need to be adopted before the line stress is raised to >30% SMYS? 216 Assuming a system operating below 30% SMYS and reassessment every 20 years, how much of a system must be assessed via CDA at the 7 and 14 year intervals? How do we determine where we must use CDA? 273 If an operator has a pipeline system that operates at pressures less than 30% SMYS, and conducts a baseline assessment for external corrosion on all cased pipe using ECDA, can subsequent re-assessments be conducted using the low stress reassessment method (49 CFR 192.941), even though all of the casings were not directly examined during the baseline assessment?

Guidance Information	1. Low stress reassessments may be used on pipeline operating below 30% SMYS as a method to reassess the integrity of a pipeline once a baseline assessment has been performed. Low stress reassessments are interim assessment methods, not primary assessment methods. Low stress reassessment requires ongoing actions to address only external and internal corrosion threats. 2. Personnel performing low stress field reassessments must be qualified under Subpart N. If personnel qualification concerns are identified with the inspectors performing the low-stress reassessments, reference should be made to the qualification requirements of §192.915, for personnel performing tasks defined by that section, or Subpart N, if personnel are performing covered tasks under the operator's OQ Plan. 3. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. A baseline assessment was not completed on a covered segment prior to using low stress reassessment. 2. Failure to follow the written procedures for performing low stress reassessments. 3. The operator did not perform remediation activities as determined by the assessment. 4. Low stress assessment used for threats other than external or internal corrosion. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. Records, including maps, survey results or other data. 4. Reassessment schedule. 5. Completed reassessment documentation. 6. SMYS calculation records. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding low-stress reassessments.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.941(b)
Section Title	What is a low stress reassessment?
Existing Code Language	(b) External corrosion. An operator must take one of the following actions to address external corrosion on the low stress covered segment. (1) Cathodically protected pipe. To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years on the covered segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. (2) Unprotected pipe or cathodically protected pipe where electrical surveys are impractical. If an electrical survey is impractical on the covered segment an operator must-- (i) Conduct leakage surveys as required by §192.706 at 4-month intervals; and (ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. ANSI ASC Z380 Gas Piping Technology Committee (GPTC) PHMSA Gas Transmission Integrity Management FAQs:

	9 Does the rule apply to gathering and other low-stress lines? 178 If a line was operating at <30% SMYS and reassessment schedules had been established based on this stress level, what requirements would need to be adopted before the line stress is raised to >30% SMYS? 216 Assuming a system operating below 30% SMYS and reassessment every 20 years, how much of a system must be assessed via CDA at the 7 and 14 year intervals? How do we determine where we must use CDA? 273 If an operator has a pipeline system that operates at pressures less than 30% SMYS, and conducts a baseline assessment for external corrosion on all cased pipe using ECDA, can subsequent re-assessments be conducted using the low stress reassessment method (49 CFR 192.941), even though all of the casings were not directly examined during the baseline assessment?
Guidance Information	1. Low stress reassessments may be used on pipeline operating below 30% SMYS as a method to reassess the integrity of a pipeline once a baseline assessment has been performed. Low stress reassessments are interim assessment methods, not primary assessment methods. Low stress reassessment requires ongoing actions to address external and internal corrosion threats. 2. For cathodically protected pipe, the operator should take periodic electrical surveys (i.e., indirect examination methods as described for ECDA).. Follow up investigation would be required if areas of concern are identified. 3. For unprotected or bare pipe where electrical surveys are not practical, an operator must conduct leakage surveys at 4 month interval. Every 18 months an operator must identify areas of active corrosion. This may be done using a cell-to-cell, side drain survey, et. al. The operator must examine leak reports, pipe inspection reports, and other data for determination of active corrosion. 4. The operator should integrate electrical survey data with applicable annual CP and leak survey data, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, test records, etc. 5. Personnel performing low stress field reassessments must also be qualified under Subpart N. If personnel qualification concerns are identified with the inspectors performing the low-stress reassessments, reference should be made to the qualification requirements of §192.915, if performing functions defined by that section, or Subpart N, if performing a covered task under the operator's OQ Plan. 6. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to follow the procedures for the use of external corrosion monitoring of low stress pipelines. 2. Failure to have written justification for concluding that any electrical surveys are impractical. 3. Failure to conduct the leakage surveys required for unprotected pipe or cathodically protected pipe where electrical surveys are impractical. 4. Leakage surveys were not done every 4 months. 5. No process for re-evaluation of areas of active corrosion every 18 months. 6. Failure to re-evaluate areas of active corrosion.

	7. Written procedures did not specify minimum data requirements for external corrosion re-evaluation. 8. Written procedures did not specify the minimum data requirements for overall CP and threat evaluation required every 7 years. 9. Failure to perform the required 7 year re-evaluation. 10. Failure to perform an appropriate electrical survey (CIS, DCGV, ACGV) for reassessment 11. Failure to perform follow up investigations for areas of concern that were identified. 12. Failure to implement appropriate remedial actions. 13. The requirements in 192.941(b) were not specified in procedures and/or implemented when using low stress reassessment for external corrosion. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. Records, including maps, electrical and leak survey results or other data. 4. Leak repair, exposed pipeline records, cathodic protection records. 5. Documentation of the pipeline environmental conditions. 6. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding low-stress reassessment.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.941(c)
Section Title	What is a low stress reassessment?
Existing Code Language	(c) Internal corrosion. To address the threat of internal corrosion on a covered segment, an operator must-- (1) Conduct a gas analysis for corrosive agents at least once each calendar year; (2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and (3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1)-(c)(2) with applicable internal corrosion leak records, incident reports, safety- related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. ANSI ASC Z380 Gas Piping Technology Committee (GPTC) PHMSA Gas Transmission Integrity Management FAQs: 9 Does the rule apply to gathering and other low-stress lines? 178 If a line was operating at <30% SMYS and reassessment schedules had been established based on this stress level, what requirements would need to be adopted before the line stress is raised to >30% SMYS? 216 Assuming a system operating below 30% SMYS and reassessment every 20 years, how much of a system must be assessed via CDA at the 7 and 14 year intervals? How do we determine where we must use CDA?

Guidance Information	1. Low stress reassessments may be used on pipeline operating below 30% SMYS as a method to reassess the integrity of a pipeline once a baseline assessment has been performed. Low stress reassessments are interim assessment methods, not primary assessment methods. Low stress reassessment requires ongoing actions to address external and internal corrosion threats. 2. Operator must at least once each calendar year conduct a gas analysis. 3. The operator should define the period in their procedures for testing of fluids removed from the segment. 4. If corrosive gas or fluids are found in a covered segment the operator should remediate, and monitor in accordance with 192.477. 5. Fluid removed from storage fields must be tested at least once each calendar year. Fluid sampling should be done at a time when fluids could be introduced into a covered segment. 6. Personnel performing low stress field reassessments must be qualified under Subpart N. If personnel qualification concerns are identified with the inspectors performing the low-stress reassessments, reference should be made to the qualification requirements of §192.915, for personnel performing tasks defined by that section, or Subpart N, if personnel are performing covered tasks under the operator's OQ Plan. 7. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to follow the procedures for the use of internal corrosion monitoring of low stress pipelines. 2. Failure to conduct annual gas analyses for corrosive agents. 3. Failure to conduct periodic fluid testing. 4. Failure to define the interval for periodic fluid testing. 5. Failure to conduct the annual fluid testing for storage fields that could affect a covered segment. 6. Failure to implement appropriate remedial actions. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. Records, including maps, survey results or other data. 4. Gas Analysis results. 5. Liquid analysis and results. 6. Internal Corrosion cathodic protection records. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding low-stress reassessments.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.943
Section Title	When can an operator deviate from these reassessment intervals?
Existing Code Language	(a) Waiver from reassessment interval in limited situations. In the following limited instances, OPS may allow a waiver from a reassessment interval required by §192.939 if OPS finds a waiver would not be inconsistent with pipeline safety. (1) Lack of internal inspection tools. An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment. (2) Maintain product supply. An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval. (b) How to apply. If one of the conditions specified in paragraph (a) (1) or (a) (2) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. Federal Register Volume 78, Number 18, January 28, 2013, Pages 5866-5867

	Pipeline Safety: Annual Reports and Validation Notice of extension of submittal deadline for calendar year 2012 gas transmission and gathering annual reports, remind pipeline owners and operators to validate their Operator Identification Number data, and request supplemental reports to correct gas transmission and liquefied natural gas annual report data issues. Supplemental Guidance Appendix F.01, Continual Evaluation and Assessment Gas Piping Technology Committee (GPTC) Supplemental Guidance Appendix F.05, White Paper - Exceptional Performance. PHMSA Gas Transmission Integrity Management FAQs: 43 Can a re-assessment interval be extended beyond the maximum interval specified in 192.939? 205 Does an operator have to provide the original source documents for the covered segment of the pipeline? (Source document means actual pressure test chart for MAOP, mill test report on pipe, etc.) In the absence of original source material, will DOT accept inventory map data for pipeline information, MAOP database information, etc.? 210 If the gas transmission pipeline is under state jurisdiction, should performance measures, waivers, etc., be sent to the states' commission rather than OPS?
Guidance Information	1. The preamble to the Federal Register Notice notes that waivers issued in accordance with §192.943 must be done at least 180 days prior to end of the required assessment interval since waivers require public notice and comment. *The rule provides for a waiver from the reassessment intervals in two limited instances. In either instance the waiver has to be done in accordance with 49 U.S.C. 60118(c), which requires public notice and comment, and OPS has to find that the waiver would not be inconsistent with pipeline safety. The rule requires an operator to apply for a waiver at least 180 days before the end of the required reassessment interval, unless local product supply issues make that period impractical.* (Federal Register / Vol. 68, No. 240 / Monday, December 15, 2003 / Rules and Regulations at Page 69810.) 2. An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

	3. An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval. It should be noted that assessment planning windows are large, in years, and there should be ample time to plan for assessments. Given the long intervals between required reassessments, an operator would need to make a strong argument that either of these conditions could not have been averted by prudent planning. Waivers due to supply impacts should only apply to extenuating and unforeseeable circumstances, and not things like waiting till the last minute and then having a bad ILI run. 4. Must show that the waiver is consistent with pipeline safety. Application for a waiver must be made at least 180 days before the end of the reassessment interval. An exception may apply if local product supply issues make the 180 day submittal impractical. 5. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. Requirements for submitting a reassessment interval waiver were not consistent with §192.943. 2. A waiver was not requested when maximum reassessment intervals were exceeded. 3. Failure to file a request for a waiver regarding the availability of internal inspection tools. 4. Failure to take the necessary interim steps to ensure the integrity of the covered pipe during the waiver period. 5. Inadequate documentation to demonstrate an internal inspection tool was not available. 6. Documentation does not demonstrate that local product supply could not be maintained. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Requests for waiver. 3. Request to vendor for internal inspection. 4. Documentation from vendor regarding availability of internal inspection tools. 5. Product flow rates and deliveries. 6. Records. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding reassessment interval waivers.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.945
Section Title	What methods must an operator use to measure program effectiveness?
Existing Code Language	(a) General. An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, see §192.7 of this part), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by §191.17 of this subchapter. (b) External Corrosion Direct assessment. In addition to the general requirements for performance measures in paragraph (a) of this section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of §192.925.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-115, 75 FR 72877, November 25, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-12-10** **Pipeline Safety: Using Meaningful Metrics in Conducting Integrity Management Program Evaluations** PHMSA is issuing an Advisory Bulletin to remind operators of gas transmission and hazardous liquid pipeline facilities of their responsibilities, under Federal integrity management regulations, to perform evaluations of their integrity management programs using meaningful performance metrics. **Advisory Bulletin ADB-03-06** **Corrosion Threat to Newly Constructed Gas Transmission and Hazardous Liquid Pipelines** RSPA's Office of Pipeline Safety (OPS) is issuing this advisory bulletin to owners and operators of natural gas and hazardous liquid pipelines to consider the threat from external corrosion during and immediately after construction of new steel pipelines or pipeline segments. Operators are strongly encouraged to determine whether new pipelines are susceptible to interference and damage from stray

	electrical currents. Operators should carefully monitor and take action to mitigate any detrimental effects. **Advisory Bulletin ADB-07-01B** **Superseded by code revisions and no longer applicable.** **Advisory Bulletin ADB-05-01** **Superseded by code revisions and no longer applicable.** **Advisory Bulletin ADB-04-02** **Superseded by code revisions and no longer applicable.**
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines, Section 9.4 and Appendix A. Gas Piping Technology Committee (GPTC) (Some of this guidance has been superseded by code revisions.) PHMSA Gas Transmission Integrity Management FAQs: 136 One of the four overall performance measures required by 192.945(a) is the number of leaks, failures, and incidents (classified by cause). What is the threshold an operator should use for reporting leaks, failures, and incidents? 137 Over what time period should performance measures be determined? How often should they be updated? [Note: this FAQ has been superseded by recent Code revisions.] 159 What constitutes an "incident" of the kind for which operators implementing performance-based programs must evaluate for implications to their pipelines and IM programs (192.913(b)(1)(v)? 186 Assume that an operator runs an inline inspection tool through a 50-mile segment of pipeline, not all of which is HCA, and a new HCA is subsequently identified within the inspected pipeline. When submitting performance measures, can the operator take credit for the previous inspection when reporting "number of miles inspected versus program requirements"?
Guidance Information	1. This section has been amended from the original requirement to submit semi-annual reports of the program effective to an annual reporting of performance as part of the PHMSA annual report. The change was effective January 1, 2011. 2. Failure to submit an annual report should be cited under §191.17. Failure to collect and document the necessary performance measure should be cited under §192.945. 3. Failure to develop and/or submit the additional performance metrics required by an exceptional performance IM program should be cited under 192.913(b).

	4. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 5. The operator should bench mark their performance against industry data. 6. There should be a feedback mechanism of Integrity Management performance to corrective action programs, preventive and mitigative measures decisions, and the threat and risk analysis processes. 7. Performance measures should be periodically reviewed and updated as necessary based on an evaluation of Integrity Management Program effectiveness. 8. Operators should trend performance measures. 9. The operator should develop specific performance measures for each pipeline segment. Pipeline segments with like characteristics can be combined. Performance measures should be tailored to specific pipeline segment threats. 10. The operator's process should include provisions to compare the leak, failure, and incident data to the operator's risk model results and use these comparisons to modify the risk model (if necessary). (Note: This was a recommendation from NTSB following the investigation of the San Bruno, CA incident in 2010.) 11. Selected Final Orders Referencing §192.945: a. **Mardi Gras Pipeline, LLC, [4-2009-1007], (December 19, 2011), Item 3,** Operator failed to submit integrity management program performance records on a semi-annual basis. Specifically, the operator failed to submit timely reports for the performance measures that were due within two months after 12/31/2005, 6/30/2006, and 12/31/2006. b. **Chevron Pipe Line Co., [5-2007-1007], (June 15, 2009), Item 4A,** Operator did not conduct semi-annual evaluation of its IMP to determine its effectiveness in assessing the integrity of covered segments and in protecting HCAs.
Examples of a Probable Violation or Inadequate Procedures	1. Process did not include the use of periodic self-assessments, internal and/or external audits, management reviews, or other evaluations to measure program effectiveness. 2. Process did not include clear description of the scope, objectives, and frequency of the program effectiveness evaluations. 3. Performance metrics were not used to evaluate the IM Program. 4. Process did not specify the assignment of responsibility for implementation of the required actions. 5. Procedures were not developed for conducting IM program effectiveness evaluations. 6. The process did not require bench marking of segments against adjacent segments or segments with like characteristics. 7. Process did not include provisions for review and follow-up of program effectiveness evaluation results, findings, and recommendations with appropriate company managers. 8. Process does not require evaluation of the effectiveness of programs to address specific threats in accordance with ASME B31.8S-2004 Appendix A. 9. Process did not specify metrics that evaluate IM Program. This includes

	overall performance metrics such as the number of failures, volume spilled, etc.; metrics that reflect accomplishments of the program's objectives such as number of miles assessed, number of repairs, etc; and threat-specific metrics. 10. Process did not specify the collection of performance metric data. 11. Process did not require trending of equipment or material failure 12. Process did not require periodic review and updating of performance metrics as systems and conditions change. 13. Process did not include procedures to ensure the accuracy and completeness of performance measure data. 14. Performance goals, including segment-specific issues, were not included in the process. 15. Procedures did not document requirements to submit periodic performance metric reports 16. Performance measures were not submitted with the Annual Report. 17. The performance measures submitted with the Annual Report were incomplete. 18. No process to identify, measure, analyze, and/or report additional performance metrics (applies only to an operator that demonstrates exceptional performance in order to deviate from requirements) 19. Process does not document requirements to identify, measure, analyze, and/or report additional performance metrics (applies only to an operator that demonstrates exceptional performance in order to deviate from requirements). 20. Failure to submit performance measures to PHMSA within the required time frame. 21. Additional performance metrics for ECDA required by 192.925 were not identified, measured, and/or analyzed. 22. Failure to define measures to monitor the effectiveness of the ECDA process. 23. Failure to monitor the measures to determine the effectiveness of the ECDA process. 24. Records did not demonstrate that periodic self-assessments, internal and/or external audits, management reviews, or other evaluations to measure program effectiveness were performed. 25. Records did not demonstrate that actions were identified to improve the IM program commensurate with the trends of the performance measures. 26. Records did not demonstrate a response to performance indications that demonstrated a negative trend. 27. Records did not provide evidence of feedback to corrective action programs, preventive and mitigative measures decisions, and the threat and risk analysis processes. 28. Records did not provide evidence of management awareness of the program effectiveness evaluation results nor a commitment to address the issues identified. 29. Records did not provide evidence that the findings and recommendations of the program effectiveness evaluation were followed up on by the appropriate company managers.

	30. Records did not demonstrate that performance metrics were established and used to evaluate IM program effectiveness. 31. Records did not demonstrate that metrics were developed in accordance with ASME B31.8S-2004, Section 9. 32. Records did not demonstrate that equipment or material failures were trended. 33. Records did not demonstrate that performance metrics were updated to reflect system and condition changes. 34. Records did not show that the operator implemented its program to assure the completeness and accuracy of the data used to measure performance. 35. Records did not show that IM performance metrics reported to PHMSA are complete and accurate. 36. Records did not show that the operator established specific performance goals, including segment-specific issues. 37. Records did not show that the performance goals were reviewed and revised (if necessary) based on the results of program evaluations. 38. Records did not show the leak, failure, and incident metrics were compared to the risk model, and that changes to the risk model were made if necessary. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Performance Measures. 3. Annual report data indicating integrity management results. 4. ECDA Plan. 5. ECDA specific measures. 6. Records. 7. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.947
Section Title	What records must an operator keep?
Existing Code Language	An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection. (a) A written integrity management program in accordance with §192.907; (b) Documents supporting the threat identification and risk assessment in accordance with §192.917; (c) A written baseline assessment plan in accordance with §192.919; (d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements; (e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with §192.915; (f) Schedule required by §192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule. (g) Documents to carry out the requirements in §§192.923 through 192.929 for a direct assessment plan; (h) Documents to carry out the requirements in §192.931 for confirmatory direct assessment; (i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-95B, 69 FR 18227, April 6, 2004
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	

Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. Gas Piping Technology Committee (GPTC) PHMSA Gas Transmission Integrity Management FAQs: 32 Should operators archive previous versions of their baseline assessment plans so OPS can track changes to these plans over time? 165 Is information in an electronic database considered satisfactory documentation? 189 What certification or officer approval by the operator of the IMP is required by OPS? 238 What documentation must I include in my IM program to describe a "process" required by the rule? 239 How much detail must I include when the rule requires that I "justify" an action or decision?
Guidance Information	1. Records to be retained are typically generated in accordance with procedure. When procedures are used to implement the Rule, a requirement should be included in the procedure to distribute the record being generated to the document management location within the operator's facilities. 2. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911. 3. For records such as memoranda or notes, these documents should be retrievable from a central location to the extent practicable, as opposed to being retained exclusively by individuals without record storage responsibilities. Since many records must be retained for the life of the pipeline, this suggests that records be kept in some sort of formalized or structured record-keeping system, as opposed to individual working files. 4. As an alternative to each procedure specifying recordkeeping requirements, a single procedure that specifies all recordkeeping requirements would be considered sufficient programmatic control. 5. Selected Final Orders Referencing §192.947: a. **Columbia Gas Transmission Corp., [3-2009-1018], (November 16, 2010), Item 1A,** Operator failed to maintain records that demonstrate compliance with the requirements of the Gas IM regulations to maintain records for the useful life of the pipeline. b. **Southern Natural Gas Co., [4-2011-1012]. (June 15, 2012), Item 1,** Operator violated §§192.911, 192.925, and 192.947 by failing to maintain complete documentation supporting decisions it made in performing the pre-assessment step for the ECDA of the Graniteville Mills Expansion Line. The pre-assessment identified two casings; however, these were horizontal drills. The operator acknowledged the errors in the documentation. c. **Northwest Pipeline Corp., [5-2007-1001], (May 2, 2011), Item 1,** Operator failed to describe and document in its IMP which method it had applied to each portion of its pipeline system to identify HCAs. The operator also failed to maintain records to support any decision, analysis or

	process developed and used to implement its IMP. Specifically, it alleged that the operator failed to keep documents supporting the process(es) that had been used to identify each HCA segment. d. **CPN Pipeline Co., [5-2007-1006], (December 16, 2009), Item 1A,** Operator failed to maintain records that demonstrate compliance with the requirement to identify HCAs. Specifically, the operator failed to maintain documentation validating its use of instrumentation to establish pipeline locations and identify HCAs. The instrumentation used, such as GPS, had tolerances and potential inaccuracies not documented and accounted for to ensure the accurate identification of HCAs. e. **CPN Pipeline Co., [5-2007-1006], (December 16, 2009), Item 1B,** Operator failed to maintain records that demonstrate compliance with the requirement to develop and follow a written IMP no later than December 17, 2004. Also, the operator did not have documentation of decisions, processes, and results for various other integrity management processes.
Examples of a Probable Violation or Inadequate Procedures	1. Records specified in 192.947 were not maintained for the useful life of the pipeline. 2. The operator did not maintain records in accordance with their procedures. 3. The operator did not have documents to support all decisions, analysis, and processes developed and used to implement the elements of their integrity management program. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. Records. 4. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding records management.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.949
Section Title	How does an operator notify PHMSA?
Existing Code Language	An operator must provide any notification required by this subpart by-- (a) Sending the notification to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager PHP-10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; (b) Sending the notification to the Information Resources Manager by facsimile to (202) 366-7128; or (c) Entering the information directly on the Integrity Management Database (IMDB) Web site at http://primis.rspa.dot.gov/gasimp/.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-109, 74 FR 2889, January 16, 2009
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	**Advisory Bulletin ADB-05-04** **Integrity Management Notifications for Gas Transmission Lines** Current regulations require operators to notify OPS and state pipeline safety agencies of certain events related to integrity management programs for gas transmission lines. This bulletin provides guidance on notifying OPS and state agencies and describes OPS' review of notifications. OPS expects this bulletin to improve the efficiency of the notification and review process.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. PHMSA Gas Transmission Integrity Management FAQs: 97 What types of notifications are required by the rule? 98 When must notifications be submitted? 99 What information must be in a notification? 111 What level of change satisfies the terms "significantly modify" or "substantially affect" as used under subpart 192.909(b) regarding notification requirements for changes to an operator’s integrity management plan? 153 Must I notify OPS/state regulators if I plan to use a different model for ICDA than the one referenced in the rule?

	181 Is a safety related condition notification required when an operator implements a pressure reduction for an immediate repair? What about other pressure reducing requirements in the IM rule, is a notification required per 191.23? 245 If PHMSA completes a review of my notification for use of "other technology" and has no objections, must I still wait the remainder of the 180 days before I can implement the technology?
Guidance Information	1. §192.949 establishes requirements for where notifications should be submitted. A failure to submit a notification should be cited under the Code section specifying that a notification is required: 2. §192.909(b) specifies an operator must notify PHMSA of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program. 3. §192.921(a)(4) specifies that a notification is required 180 day before the use of "other technology" as a baseline assessment. 4. §192.933(a)(1) specifies that an operator must notify PHMSA if it cannot meet the schedule for evaluation and remediation required under 192.933 (c) and cannot provide safety through temporary reduction in operating pressure or other action. The operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State. 5. §192.933(a)(2) specifies that when a pressure reduction exceeds 365 days, the operator must notify PHMSA under §192.949 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State. 6. §192.937(c)(4) specifies that a notification is required 180 day before the use of "other technology" as a reassessment. 7. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to have a procedure to provide notifications to PHMSA required by this subpart. 2. Failure to follow their procedures for providing notification to PHMSA as required by Subpart O.

	Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.
Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. State Notifications. 3. PHMSA Notifications. 4. Records. 5. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding notifications.
Other Special Notations	

Enforcement Guidance	Part 192 Gas Transmission Pipeline Integrity Management
Revision Date	2/12/2014
Code Section	§192.951
Section Title	Where does an operator file a report?
Existing Code Language	An operator must file any report required by this subpart electronically to the Pipeline and Hazardous Materials Safety Administration in accordance with §191.7 of this subchapter.
Origin of Code	Amdt. 192-95, 68 FR 69778, December 15, 2003
Last Amendment	Amdt. 192-115, 75 FR 72877, November 25, 2010
Interpretation Summaries	
Advisory Bulletin/Alert Notice Summaries	The ADBs associated with this code section in WINDOT have been superseded by code revisions and are no longer applicable.
Other Reference Material & Source	ASME B31.8S-2004, Supplement to B31.8 on Managing System Integrity of Gas Pipelines. The WINDOT GPTC guidance has been superseded by code revisions and is no longer applicable.
Guidance Information	1. §192.951 and§ 191.7 specify where reports are to be filed. Failure to submit an annual report should be cited under §191.17. Inadequate procedures for, or failure to collect, document and submit the necessary performance measures as part of the annual report should be cited under §192.945. 2. Failure to develop and/or submit the additional performance metrics required by an exceptional performance IM program should be cited under 192.913(b). An amendment to this section removed the option for operator's to file performance reports to PHMSA by mail or facsimile. The effective date requiring electronic submissions on January 1, 2011. 3. Failure to have procedures to address this Integrity Management element should be cited under the appropriate paragraph of §192.911.
Examples of a Probable Violation or Inadequate Procedures	1. Failure to follow procedures for filing reports with PHMSA. *Depending on the circumstances, some of the examples listed in this section may be inadequate plans and procedures, and not probable violations. Thus, the enforcement tool to address these issues would be a Notice of Amendment and not a Notice of Probable Violation or a Warning Letter. Section 3 of the Enforcement Procedures provides guidance on selecting the appropriate enforcement action.*

Examples of Evidence	1. Integrity Management Plan or Program, or applicable portion that shows an omission or deficiency in the Plan or Program. 2. Appropriate operations and maintenance procedures. 3. Prior performance reports. 4. Evidence that reports were not filed as required by Part 192. 5. Operator records. 6. Documented conversations with operator or contractor personnel identifying inconsistencies or problems regarding submittal of reports to PHMSA.
Other Special Notations	